Sempra Energy®

2001

Financial Report

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

This portion of the Financial Report Section of the 2001 Annual Report to Shareholders includes management's discussion and analysis of operating results from 1999 through 2001, and provides information about the capital resources, liquidity and financial performance of Sempra Energy and its subsidiaries. It also focuses on the major factors expected to influence future operating results and discusses investment and financing plans. It should be read in conjunction with the consolidated financial statements included in this Annual Report. References to the company are to Sempra Energy, or Sempra Energy and its subsidiaries, as indicated by the context.

The company is a California-based Fortune 500 energy services company whose principal utility subsidiaries are San Diego Gas & Electric (SDG&E), which provides electric and natural gas service in San Diego County and southern Orange County, and Southern California Gas Company (SoCalGas), the nation's largest natural gas distribution utility, serving 18 million customers through 5 million meters throughout most of Southern California and part of central California. Together, the two utilities (the California utilities) serve approximately 21 million customers through 7 million meters.

In addition, Sempra Energy owns and operates other regulated and unregulated subsidiaries. Sempra Energy Global Enterprises (Global) is the holding company for most of these businesses, primarily consisting of the following: Sempra Energy Trading (SET) is engaged in the wholesale trading and marketing of natural gas, power, petroleum and other commodities. Sempra Energy Resources (SER) develops power plants and natural gas storage, production and transportation facilities within the United States and the adjacent portion of Mexico. Sempra Energy International (SEI) develops, operates and invests in energy-infrastructure systems primarily in Latin America. Sempra Energy Solutions (SES) provides an integrated mix of retail energy services, including facility management, supply and price-risk management, energy efficiency, energy-asset management and infrastructure ownership.

Sempra Energy Financial (SEF) invests in limited partnerships, which own 1,300 affordable-housing properties throughout the United States, Puerto Rico and the Virgin Islands. Through other subsidiaries, the company is involved in other energy-related products and services.

CAPITAL RESOURCES AND LIQUIDITY

The company's California utility operations have historically been a major source of liquidity. However, beginning in the third quarter of 2000 and continuing into the first quarter of 2001, SDG&E's liquidity and its ability to make funds available to Sempra Energy were adversely affected by the electric cost undercollections resulting from a temporary ceiling on electric rates legislatively imposed in response to high electric costs. Significant growth in these undercollections has ceased as a result of an agreement with the California Department of Water and Resources (DWR), under which the DWR is obligated to purchase SDG&E's full net short position consisting of the power and ancillary services required by SDG&E's customers that are not provided by SDG&E's nuclear generating facilities or its previously existing purchase power contracts. The agreement extends through December 31, 2002. In addition, the California Public Utilities Commission (CPUC) is conducting proceedings intended to establish guidelines and procedures for the eventual resumption of electricity procurement by SDG&E and the other California investor-owned utilities (IOUs). In addition, electric costs are now below and are expected to remain below the rates under the rate ceiling. See further discussion in Note 14 of the notes to Consolidated Financial Statements.

In June 2001, representatives of California Governor Davis, the DWR, Sempra Energy and SDG&E entered into a Memorandum of Understanding (MOU) contemplating the implementation of a series of transactions and regulatory settlements and actions to resolve many of the issues affecting SDG&E and its customers arising out of the California energy crisis. Many of the significant elements of the MOU have received the requisite approvals of the CPUC and have been implemented. These include settlement of reasonableness reviews and the application by SDG&E of its $100 million refund involving the prudence of its purchase-power costs and its overcollections in other regulatory balancing accounts to reduce the rate-ceiling balancing account to $392 million at December 31, 2001.

However, in January 2002, the CPUC rejected the MOU's proposed settlement regarding the rate-making treatment of favorably priced intermediate-term electricity purchase contracts held by SDG&E. In May 2001, the CPUC issued a decision that, effective February 1, 2001, electricity purchased under these contracts was to be provided by SDG&E to its customers at cost. This decision is inconsistent with prior CPUC staff positions that the electricity was to be provided at current market prices, with any resulting profits or losses borne by SDG&E.

In accordance with the May 2001 CPUC decision, SDG&E ceased recording profits from these contracts effective February 1, 2001, and none of the profits from the contracts, which have now expired, are included in the rate-ceiling balancing account. SDG&E had appealed the CPUC's decision to the California Court of Appeals, but held the appeal in abeyance pending the settlement contemplated by the MOU, under which $219 million of the contract profits (including those that would have been attributable to periods subsequent to February 1, 2001 and, therefore, are not reflected in income) would have been applied to reduce the rate-ceiling balancing account, with the balance of the profits retained by SDG&E. Following the CPUC rejection of this portion of the MOU in January 2002, SDG&E is proceeding with its appeal and has also filed a complaint in federal district court in San Diego against the CPUC alleging that the Commission's actions constitute an unconstitutional taking and have denied SDG&E its due process rights. The timing and manner of resolution of this issue will affect SDG&E's cash flows from the rate-ceiling balancing account.

For additional discussion, see "Factors Influencing Future Performance-Electric Industry Restructuring and Electric Rates" herein and Note 14 of the notes to Consolidated Financial Statements.

At December 31, 2001, the company had available $605 million in cash and $2.5 billion in unused, committed lines of credit. Management believes these amounts, cash flows from operations and new security issuances will be adequate to finance capital expenditures, shareholder dividends, any new business acquisitions or start-ups, and other commitments. If cash flows from operations were significantly reduced and/or the company were to be unable to issue new securities under acceptable terms, neither of which is considered likely, the company would be required to reduce non-utility capital expenditures and investments in new businesses.

At the California utilities, cash flows from operations and new securities issuances are expected to be adequate to meet utility capital expenditure requirements and provide significant funds to the company, which the company can apply toward shareholder dividend requirements and other needs.

SET provides cash to or requires cash from Sempra Energy as the level of its net trading assets fluctuates with prices, volumes, margin requirements (which are substantially affected by credit ratings and price fluctuations) and the length of its various trading positions. Its status as a source or use of Sempra Energy cash also depends on its level of borrowing from its own sources.

SER's projects are expected to be financed through a combination of a synthetic lease, project financing, SER's borrowings and funds from the company. Its capital expenditures over the next several years are expected to require a significant level of funding.

SEI is expected to require funding from the company and/or external sources to continue the expansion of its existing natural gas distribution operations in Mexico and its planned expansion involving natural gas transportation pipelines. SEI's South American operations are expected to be a net provider of funds for these purposes.

SES is expected to require moderate amounts of cash in the near future as it continues its expansion program. SEF is expected to continue to be a net provider of cash through reductions of consolidated income tax payments resulting from its investments in affordable housing and other ventures.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $732 million, $882 million and $1,188 million for 2001, 2000 and 1999, respectively.

The decrease in cash flows from operating activities in 2001 compared to 2000 was primarily the result of balancing account activity at SoCalGas. This included returns of prior overcollections and the temporary effects of higher-than-expected costs of natural gas and public purpose programs and lower-than-expected sales volumes. The SoCalGas activity was partially offset by the increase in overcollected balancing accounts at SDG&E and lower customer refunds paid by SDG&E in 2001 (see below).

The decrease in cash flows from operating activities in 2000 compared to 1999 was due to increased net trading assets, SDG&E's refunds to customers for surplus rate-reduction-bond proceeds, SDG&E's cost undercollections related to high electric-commodity prices, and energy charges in excess of the 6.5 cents per kilowatt-hour (kWh) ceiling in accordance with AB 265 (see "California Utility Operations" below and Note 14 of the notes to Consolidated Financial Statements) and increased accounts receivable. These factors were partially offset by higher overcollected regulatory balancing accounts at SoCalGas, increased accounts payable and lower income tax payments. The increases in accounts receivable and accounts payable were primarily due to higher sales volumes and higher prices for natural gas and purchased power.

CASH FLOWS USED IN INVESTING ACTIVITIES

Net cash used in investing activities totaled $1,039 million, $924 million and $789 million for 2001, 2000 and 1999, respectively.

For 2001, cash flows used in investing activities primarily consisted of capital expenditures for the upgrade and expansion of California utility plant, construction costs for facilities under development in Mexico, and investments in generating plants being constructed in the western United States, partially offset by net proceeds received from the sale of the company's investment in Energy America, a residential energy-commodity retailer.

For 2000, cash flows from investing activities consisted primarily of capital expenditures of $522 million for utility plant and $167 million for investments in South America.

Capital Expenditures

Capital expenditures increased to $1.1 billion in 2001, compared with $759 million in 2000. The $300 million increase was primarily due to power plant construction costs for Termoelectrica de Mexicali (see further discussion under "Consolidated Subsidiaries" below) and increased costs associated with improving SoCalGas' distribution system. Capital expenditures for property, plant, and equipment by the California utilities were $601 million.

Capital expenditures were $170 million higher in 2000 compared to 1999 due to improvements to SDG&E's electric distribution system and to the California utilities' gas systems, investments in gas distribution facilities in Canada and Mexico and expenditures for gas turbines associated with SER's Elk Hills Power Project (see further discussion under "Unconsolidated Subsidiaries" below and Note 3 of the notes to Consolidated Financial Statements).

Over the next five years, the company expects to make capital expenditures of $3.9 billion at the California utilities and is committed to $1.0 billion of capital expenditures at the other subsidiaries, including $700 million for the four new power plants being constructed by SER. In addition, the company is evaluating an additional $2.5 billion of capital expenditures, which are not yet committed.

Construction, investment and financing programs are continuously reviewed and revised by the company in response to changes in economic conditions, competition, customer growth, inflation, customer rates, the cost of capital, and environmental and regulatory requirements. The construction program is also tied to SER's contract to supply electricity to the DWR, as discussed below under "Sempra Energy Resources."

Capital expenditures in 2002 are expected to be significantly higher than in 2001. Significant capital expenditures are expected to include $1.5 billion for California utility plant improvements and the SER power plant construction. These expenditures are expected to be financed partly by security issuances.

Investments

Investments and acquisition costs were $111 million, $243 million and $639 million for 2001, 2000 and 1999, respectively, as the company has made various investments and entered into several joint ventures over the three-year period.

During 2001, SER invested $91 million into the Elk Hills Power Project (Elk Hills), a $410 million, 570-megawatt power plant near Bakersfield, California. Elk Hills is being developed in a 50/50 joint venture with Occidental Energy Ventures Corporation (Occidental) and will supply electricity to California. Through December 31, 2001, SER had invested a total of $133 million in the project, which is anticipated to be completed during the first half of 2003. Information concerning litigation with Occidental is provided in Note 13 of the notes to Consolidated Financial Statements.

In October 2000, SEI invested an additional $147 million in two Argentine natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.). In addition, SES purchased Connectiv Thermal Systems' 50-percent interests in Atlantic-Pacific Las Vegas and Atlantic-Pacific Glendale for a total of $40 million in August 2000, thereby acquiring full ownership of these companies. In September 2000, the company acquired for $8 million a significant interest in Atlantic Electric and Gas in the United Kingdom, a retail energy marketer.

In June 1999, SEI and PSEG Global (PSEG) jointly purchased 90 percent of Chilquinta Energia S.A. (Energia) at a total cost of $840 million. With the January 2000 joint purchase of an additional 9.75 percent, the companies jointly and equally hold 99.98 percent of Energia. In September 1999, SEI and PSEG completed their acquisition of 47.5 percent of Luz del Sur S.A.A. (Luz). SEI's share of the transaction was $108 million. This acquisition, combined with the interest already owned through Energia, increased the companies' total joint and equal ownership to 84.5 percent of Luz. SEI's carrying value of the Luz investment was $114 million and $121 million as of December 31, 2001 and 2000, respectively.

In February 2002, SET acquired London-based Enron Metals Limited, the leading metals trader on the London Metals Exchange, for $145 million and changed its name to Sempra Metals Limited.

The company's level of investments in the next few years may vary substantially and will depend on the availability of financing and business opportunities providing desirable rates of return.

Consolidated Subsidiaries

In addition to its principal, wholly owned subsidiaries, the company has various other investments in which it owns greater than fifty percent of the subsidiary. The acquisitions of these subsidiaries are accounted for under the purchase method of accounting. The subsidiaries in which significant capital commitments exist are noted below. Further information concerning these subsidiaries is provided in Note 3 of the notes to Consolidated Financial Statements.

Sempra Energy International

In June 2000, SEI and PG&E Corporation announced an agreement to construct the North Baja Pipeline, a $230 million, 215-mile natural gas pipeline which will extend from Arizona to the Rosarito Pipeline south of Tijuana. The agreement calls for SEI to construct, own and operate the 135-mile segment of the pipeline within Mexico, and PG&E Corporation to construct, own and operate the 80-mile segment within the United States. The 30-inch pipeline will deliver 500 million cubic feet per day of natural gas to new generation facilities in Baja California, including SER's Termoelectrica de Mexicali power plant discussed below. SEI has begun construction of the pipeline and has recorded capital investments of $75 million as of the end of 2001. Completion of SEI's portion of the project is contemplated for the summer of 2002.

SEI's Mexican subsidiaries Distribuidora de Gas Natural (DGN) de Mexicali, DGN de Chihuahua and DGN de La Laguna Durango are the licensees to build and operate natural gas distribution systems in Mexicali, Chihuahua, and the La Laguna-Durango zone in north-central Mexico, respectively. SEI owns interests of 60, 95 and 100 percent in the projects, respectively. As of December 31, 2001, DGN-Mexicali, DGN-Chihuahua and DGN-La Laguna Durango have capital investments of $22 million, $52 million and $25 million, respectively.

Sempra Energy Resources

In February 2001, the company announced plans to construct Termoelectrica de Mexicali, a $350 million, 600-megawatt power plant near Mexicali, Mexico. Fuel for the plant will be supplied via the planned pipeline from Arizona to Tijuana discussed above. It is anticipated that the electricity produced by the plant will be exported for consumption in the United States via the 230,000-volt transmission line which is also under construction. Construction of the power plant began in the second half of 2001. $135 million has been invested in the project, which is scheduled for completion by mid-2003.

In December 2000, SER obtained approval from the appropriate state agencies to construct the Mesquite Power Plant. Located near Phoenix, Arizona, Mesquite Power is a $700 million, 1,200-megawatt project which will provide electricity to wholesale energy markets in the Southwest region. Ground was broken in March 2001, with project completion anticipated in 2003. The project is being financed partially via the synthetic lease agreement described in Note 13 of the notes to Consolidated Financial Statements.

Unconsolidated Subsidiaries

Investments in which Sempra Energy owns twenty to fifty percent of the affiliated company are accounted for under the equity method. The company's pro rata shares of the net assets of these affiliates are recorded as investments, and are adjusted for the company's share of each affiliate's earnings and dividends. Investments in affiliated companies accounted for under the equity method amounted to $1.1 billion and $1.3 billion at December 31, 2001 and 2000, respectively, which included goodwill of $248 million and $280 million, respectively, as described in Note 3 of the notes to Consolidated Financial Statements. Earnings are recorded as equity earnings on the Statements of Consolidated Income within the caption “other income - net.” In 2001, the company recorded $12 million in equity earnings, received dividends of $80 million and, due to a foreign currency translation adjustment, reduced the carrying value of its Argentine investments by $155 million. Investments in unconsolidated subsidiaries or joint ventures in which significant capital commitments exist are noted below.

Sempra Energy International

SEI is involved in several investments and projects. In October 2001, SEI and CMS Energy Corporation announced plans to jointly develop an LNG receiving facility on a 300-acre site along the Pacific coast near Ensenada, Mexico. The joint venture will develop the $400 million facility and related port infrastructure, which will provide one billion cubic feet per day of natural gas. SEI has entered into a memorandum of understanding with a Bolivian consortium for the supply of LNG to the facility. Commercial operation of the facility is scheduled to begin in late 2005.

Sempra Energy Resources

SER has invested $133 million in the Elk Hills Power project described above. SER anticipates its share of the remaining construction costs will be $70 million.

See further discussion of investing activities, including the $155 million adjustment relating to Argentina, in Note 3 of the notes to Consolidated Financial Statements.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash provided by (used in) financing activities totaled $275 million, $192 million and ($336) million for 2001, 2000 and 1999, respectively.

Net cash provided by financing activities in 2001 was more than that provided in 2000 due to greater issuances of debt (excluding that related to common stock repurchases which occurred in 2000).

Net cash was provided by financing activities in 2000 compared to being used in 1999, due to the issuance of long-term and short-term debt in 2000 (excluding that related to the repurchase of common stock), and lower common stock dividends.

Long-Term and Short-Term Debt

In 2001, the company issued $500 million in long-term debt, primarily for capital expenditures by the Global subsidiaries. The net short-term debt increase of $310 million in 2001 primarily represented borrowings through Global. Funds were used to finance construction costs of various power plant and pipeline projects in Mexico by SEI, and investments by SER for generating plants being constructed in California and Arizona. During 2001, $82 million of the Employee Stock Ownership (ESOP) debt and $25 million of variable-rate unsecured bonds were remarketed at 7.375 percent and 6.75 percent, respectively. $60 million of variable-rate industrial development bonds were put back by holders in 2000 and also remarketed in 2001. In addition, SEI refinanced $160 million of long-term notes through an unconsolidated affiliate. Repayments on long-term debt in 2001 included $150 million of first-mortgage bonds, $66 million of rate-reduction bonds and $120 million of unsecured debt.

In 2000, the company issued $500 million of long-term notes and $200 million of mandatorily redeemable trust preferred securities to finance the repurchase of 36.1 million shares of its outstanding common stock. The company issued an additional $300 million of long-term notes during 2000 to repay a portion of its short-term debt. The net increase in short-term debt primarily represents borrowings through Global, used to finance the construction of natural gas distribution systems by SEI; and borrowings by SET to finance increased trading activities. Repayments on long-term debt in 2000 included $10 million of first-mortgage bonds, $65 million of rate-reduction bonds and $51 million of unsecured debt. In addition, as noted above during December 2000, $60 million of variable-rate industrial development bonds were put back by the holders and subsequently remarketed in February 2001 at a fixed interest rate of 7 percent.

In 1999, repayments on long-term debt included $28 million of first-mortgage bonds, $66 million of rate-reduction bonds and $82 million of unsecured notes. The long-term debt issued in 1999 related primarily to the purchase of Energia. See additional discussion in Note 3 of the notes to Consolidated Financial Statements. The increase in short-term debt primarily represents borrowings through Global to finance a portion of SEI's acquisitions.

Stock Purchases and Redemptions

As noted above, in February 2000, the company completed a self-tender offer, purchasing 36.1 million shares of its outstanding common stock at $20 per share. In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase additional shares of common stock from time to time in the open market or in privately negotiated transactions. The company acquired 60,000 shares and 162,400 shares under this authorization in 2001 and 2000, respectively.

Dividends

Dividends paid on common stock amounted to $203 million in 2001, compared to $244 million in 2000 and $368 million in 1999. The lower dividends in 2001 were due to the 36.1 million stock repurchase noted above. The decrease in 2000 was due to a reduction in the quarterly dividend to $0.25 per share from its previous level of $0.39 per share and to the stock repurchase.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of the California utilities' capital structure limits to $458 million the portion of the California utilities' December 31, 2001, retained earnings that is available for dividends to the company.

Capitalization

Total capitalization at December 31, 2001, was $7.6 billion. The debt-to-capitalization ratio was 60 percent at December 31, 2001. Significant changes in capitalization during 2001 include the increase in short-term debt and the effect of the $155 million non-cash reduction to equity to reflect the devaluation of the Argentine peso and its effect on the two Argentine investments held by SEI.

Cash and Cash Equivalents

At December 31, 2001, the company had $2.5 billion of committed lines of credit, none of which were borrowed. Also at December 31, 2001, the company had $548 million of uncommitted lines of credit, of which $261 million was available for additional borrowings or additional letters of credit. A description of the credit lines and other information concerning them and related matters is provided in Notes 4, 5 and 13 of the notes to Consolidated Financial Statements. Management believes these amounts, cash flows from operations and new security issuances will be adequate to finance capital expenditures, shareholder dividends, any new business acquisitions or start-ups, and other commitments.

Commitments

The following is a summary of the company's contractual commitments at December 31, 2001 (in millions of dollars). Additional information concerning these commitments is provided above and in Notes 4, 5, 11 and 13 of the notes to Consolidated Financial Statements.

	By Period				
Description	2002	2003 and 2004	2005 and 2006	Thereafter	Total
Short-term debt	$ 875	$ —	$ —	$ —	$ 875
Long-term debt	242	883	487	2,066	3,678
Mandatorily redeemable trust preferred securities	—	—	—	200	200
Preferred stock of subsidiaries subject to mandatory redemption	—	3	3	19	25
Operating leases	66	172	186	1,183	1,607
Purchased power contracts	224	390	343	2,000	2,957
Natural gas contracts	649	545	289	155	1,638
Construction commitments	622	130	25	25	802
Environmental commitments	18	29	23	—	70
Totals	$2,696	$2,152	$1,356	$5,648	$11,852

Credit Ratings

Credit ratings for Sempra Energy and its primary, rated subsidiaries are as follows:

(As of March 11, 2002)	S&P	Moody's	Fitch
SEMPRA ENERGY			
Unsecured Debt	A	A2	A
Commercial Paper	A-1	P-1	F1
Trust Preferred Securities	BBB+	A3	A-
SDG&E			
Secured Debt	AA-	Aa3	AA
Unsecured Debt	A+	A1	AA-
Preferred Stock	A	A3	A+
Commercial Paper	A-1+	P-1	F1+
SOCALGAS			
Secured Debt	AA-	A1	AA
Unsecured Debt	A+	A2	AA-
Preferred Stock	A	Baa1	A+
Commercial Paper	A-1+	P-1	F1+
PACIFIC ENTERPRISES			
Preferred Stock	A-	-	A+
SEMPRA ENERGY GLOBAL ENTERPRISES			
Unsecured Debt	-	A2	-
Commercial Paper	A-1	P-1	F1

In late 2000, California regulatory uncertainties led the credit-rating agencies to change their rating outlooks on some of these securities to negative. Currently, Sempra Energy has negative outlooks from S&P and Moody's. SDG&E has negative outlooks from S&P, Moody's and Fitch. Both PE and SoCalGas have negative outlooks from S&P.

RESULTS OF OPERATIONS

2001 Compared to 2000

Net income for 2001 increased to $518 million, or $2.52 per diluted share of common stock, from $429 million, or $2.06 per diluted share of common stock, in 2000.

The $89 million increase in net income was primarily due to higher earnings achieved by SET, as a result of higher volatility in energy markets during the first half of 2001 and a substantial increase in trading volumes. Also contributing to the increase was a $20 million after-tax gain on the sale of Energy America in 2001, and the effect in 2000 of a $30 million after-tax charge at SDG&E for regulatory issues. These factors were partially offset by lower income generated at SER and SEI. The lower income at SER primarily resulted from the contracted sale of electricity to the DWR at a discounted price, as discussed in "Sempra Energy Resources" below. The decrease at SEI was due to a $25 million after-tax charge for its surrender of a natural gas franchise in Nova Scotia. See additional discussion in "California Utility Operations," "Sempra Energy Trading," "Sempra Energy International" and "Other Operations" below.

For the fourth quarter of 2001, net income was $107 million, or $0.52 per diluted share of common stock, compared with $95 million, or $0.47 per diluted share of common stock, for the fourth quarter of 2000. The increase in quarterly earnings was primarily attributable to the favorable settlement of various income tax issues, partially offset by lower prices and reduced volatility in the energy market, and development costs on new power plants.

In 2001, book value per share increased to $13.16 from $12.35 in 2000, primarily because net income exceeded the sum of dividends and the foreign currency translation loss related to the Argentine peso.

2000 Compared to 1999

Net income for 2000 increased to $429 million, or $2.06 per diluted share of common stock, from $394 million, or $1.66 per diluted share of common stock, in 1999.

The $35 million increase in net income was primarily due to higher earnings achieved by SET and, to a much lesser extent, by SEI and SER. These increases were partially offset by lower income generated from the California utility operations and higher interest expense. The lower income at the California utilities resulted primarily from the SDG&E charge noted above.

For the fourth quarter of 2000, net income was $95 million, or $0.47 per diluted share of common stock, compared with $105 million, or $0.44 per diluted share of common stock, for the fourth quarter of 1999. The decrease in earnings was primarily attributable to increased interest costs and income taxes, partially offset by higher earnings from the company's trading and generation operations. The increase in earnings per share was due to the decrease in weighted average shares for the fourth quarter of 2000 in comparison to the corresponding period in 1999, partially offset by the lower net income.

In 2000, book value per share decreased to $12.35 from $12.58 in 1999, due to the repurchase of 36.1 million shares of common stock in February 2000, at a price higher than book value.

CALIFORNIA UTILITY OPERATIONS

To understand the operations and financial results of the California utilities, it is important to understand the ratemaking procedures that they follow.

The California utilities are regulated by the CPUC. It is the responsibility of the CPUC to determine that utilities operate in the best interests of their customers and have the opportunity to earn a reasonable return on investment. In 1996, California enacted legislation restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates. As part of the framework for a competitive electric-generation market, the legislation established the California Power Exchange (PX) and the Independent System Operator (ISO). The PX served as a wholesale power pool and the ISO scheduled power transactions and access to the transmission system. Due to subsequent industry restructuring developments, the PX suspended its trading operations in January 2001.

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. In December 2001, the CPUC issued a decision adopting several provisions that the California utilities believe will make gas service more reliable, efficient and better tailored to the desires of customers. The CPUC is still considering the schedule for implementation of these regulatory changes, but it is expected that most of the changes will be implemented during 2002.

In connection with restructuring of the electric and natural gas industries, the California utilities received approval from the CPUC for Performance-Based Ratemaking (PBR). Under PBR, income potential is tied to achieving or exceeding specific performance and productivity measures, rather than to expanding utility plant in a market where a utility already has a highly developed infrastructure.

See additional discussion of these situations under "Factors Influencing Future Performance" and in Notes 14 and 15 of the notes to Consolidated Financial Statements.

The tables below summarize the California utilities' natural gas and electric volumes and revenues by customer class for the years ended December 31, 2001, 2000 and 1999.

GAS SALES, TRANSPORTATION AND EXCHANGE
(Dollars in millions, volumes in billion cubic feet)
for the years ended December 31

	Gas Sales		Transportation and Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
2001:						
Residential	**297**	**$2,797**	**2**	**$ 6**	**299**	**$2,803**
Commercial and industrial	**113**	**903**	**262**	**174**	**375**	**1,077**
Electric generation plants	**—**	**—**	**417**	**104**	**417**	**104**
Wholesale	**—**	**—**	**40**	**10**	**40**	**10**
	410	**$3,700**	**721**	**$294**	**1,131**	**3,994**
Balancing accounts and other						**377**
Total						**$4,371**
2000:						
Residential	284	$2,446	3	$ 13	287	$2,459
Commercial and industrial	107	760	339	225	446	985
Electric generation plants	—	—	373	130	373	130
Wholesale	—	—	25	18	25	18
	391	$3,206	740	$386	1,131	3,592
Balancing accounts and other						(287)
Total						$3,305
1999:						
Residential	313	$2,091	3	$ 10	316	$2,101
Commercial and industrial	105	560	324	243	429	803
Electric generation plants	18	7*	218	83	236	90
Wholesale	—	—	23	11	23	11
	436	$2,658	568	$347	1,004	3,005
Balancing accounts and other						(94)
Total						$2,911

* Consists of the interdepartmental margin on SDG&E's sales to its power plants prior to their sale in the first half of 1999.

ELECTRIC SALES
(Dollars in millions, volumes in million kWhs)
for the years ended December 31

	2001		2000		1999	
	Volumes	**Revenue**	Volumes	Revenue	Volumes	Revenue
Residential	**6,011**	**$ 775**	6,304	$ 730	6,327	$ 663
Commercial	**6,107**	**753**	6,123	747	6,284	592
Industrial	**2,792**	**325**	2,614	310	2,034	154
Direct access	**2,464**	**84**	3,308	99	3,212	118
Street and highway lighting	**89**	**10**	74	7	73	7
Off-system sales	**249**	**39**	899	59	383	10
	17,712	**1,986**	19,322	1,952	18,313	1,544
Balancing and other		**(359)**		232		274
Total	**17,712**	**$1,627**	19,322	$2,184	18,313	$1,818

2001 Compared to 2000

Natural gas revenues increased from $3.3 billion in 2000 to $4.4 billion in 2001, and the cost of natural gas distributed increased from $1.6 billion in 2000 to $2.5 billion in 2001. These increases were primarily due to higher average natural gas prices and higher volumes of gas sales in 2001. Under the current regulatory framework, changes in core-market natural gas prices (gas purchased for customers who are primarily residential and small commercial and industrial customers, without alternative fuel capability) do not affect net income, since core customer rates generally recover the actual cost of natural gas on a substantially concurrent basis. See discussion of balancing accounts in Note 2 of the notes to Consolidated Financial Statements.

Electric revenues decreased from $2.2 billion in 2000 to $1.6 billion in 2001, and the cost of electric fuel and purchased power decreased from $1.3 billion in 2000 to $0.7 billion in 2001. These decreases were primarily due to the DWR's purchases of SDG&E's net short position. These purchases and the corresponding sale to SDG&E's customers are not included in the Statements of Consolidated Income since SDG&E was merely transporting the electricity from the DWR to the customers. Similarly, PX/ISO power revenues have been netted against purchased-power expense to avoid double-counting as SDG&E sells power into the PX/ISO and then purchases power therefrom. In addition, volumes were down compared to 2000 due to reductions in customer demand, arising from conservation efforts encouraged by the State of California program to give bill credits (funded by the DWR) to customers who significantly reduced usage. It is uncertain when SDG&E's electric volumes will return to levels of prior years.

Other operating expenses increased from $1.1 billion in 2000 to $1.3 billion in 2001. The increase was primarily due to increased wages and employee benefits costs, as well as an increase in operation costs associated with balancing accounts.

2000 Compared to 1999

Natural gas revenues increased from $2.9 billion in 1999 to $3.3 billion in 2000, primarily due to higher prices for natural gas in 2000 and higher electric generation plant revenues. The increase in electric generation plant revenues was due to higher demand for electricity in 2000 and the sale of SDG&E's fossil fuel generating plants in the second quarter of 1999. Prior to the plant sale, SDG&E's natural gas revenues from these plants consisted of the margin from the sales. Subsequent to the plant sale, SDG&E’s gas revenues consisted of the price of the natural gas transportation service since the sales now are to unrelated parties. In addition, the generating plants receiving gas transportation from the California utilities were operating at higher capacities than previously, as discussed below.

Electric revenues increased from $1.8 billion in 1999 to $2.2 billion in 2000. The increase was primarily due to higher sales to industrial customers and the effect of higher electric commodity costs, partially offset by the $50 million pretax charge at SDG&E for a potential regulatory disallowance related to the acquisition of wholesale power in the deregulated California market, and the decrease in base electric rates (the noncommodity portion) from the completion of stranded cost recovery. For 2000, SDG&E’s electric revenues included an undercollection of $447 million as a result of the 6.5-cent rate cap.

The cost of natural gas distributed increased from $1.2 billion in 1999 to $1.6 billion in 2000. The increase was largely due to higher prices for natural gas. Prices for natural gas increased due to the increased use of natural gas to fuel electric generation, colder winter weather and population growth in California.

The cost of electric fuel and purchased power increased from $0.5 billion in 1999 to $1.3 billion in 2000. The increase was primarily due to the higher cost of electricity from the PX that has resulted from higher demand for electricity and the shortage of power plants in California, higher prices for natural gas used to generate electricity (as described above), the sale of SDG&E’s fossil fuel generating plants, and warmer weather in California. Under the current regulatory framework, changes in on-system prices normally do not affect net income. See the discussions of balancing accounts and electric revenues in Note 2 of the notes to Consolidated Financial Statements.

In September 2000, as a result of high electricity costs the CPUC authorized SDG&E to purchase up to 1,900 megawatts of power directly from third-party suppliers under both short-term contracts and long-term contracts. Subsequent to December 31, 2000, the state of California authorized the DWR to purchase all of SDG&E’s power requirements not covered by its own generation or by existing contracts. These and related events are discussed more fully in Note 14 of the notes to Consolidated Financial Statements.

Depreciation and amortization expense decreased from $0.8 billion in 1999 to $0.5 billion in 2000 and other operating expenses decreased from $1.2 billion in 1999 to $1.1 billion in 2000. Both decreases were primarily due to the 1999 sale of SDG&E’s fossil fuel generating plants.

SEMPRA ENERGY TRADING

SET, a leading marketer of natural gas, electricity, petroleum, petroleum products and other commodities headquartered in Stamford, Connecticut, was acquired on December 31, 1997. SET is a full-service energy trading company and also has offices in Europe, Canada and Asia. For the year ended December 31, 2001, SET recorded net revenues of $1.0 billion compared to $795 million for the prior year. SET’s gross revenues were $33.5 billion and $25.6 billion in 2001 and 2000, respectively.

For the year ended December 31, 2001, SET recorded net income of $196 million, compared to net income of $155 million and $19 million in 2000 and 1999, respectively. The increase in net income in 2001 compared to 2000 was primarily due to high volatility in energy markets during the first half of 2001 and an increase in trading volumes, partially offset by reduced profitability in Europe. The increase in net income for 2000 compared to 1999 was due to increased volatility in the U.S. energy markets and higher earnings from European crude oil trading.

A summary of SET's unrealized revenues for trading activities for the year ended December 31, 2001 (in millions of dollars) follows:

Balance at beginning of year	$ (72)
Additions	1,333
Realized	856
Balance at end of year	$ 405

The estimated fair values for SET's trading activities as of December 31, 2001, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	2002	2003 and 2004	2005 and 2006	Thereafter	Total fair value
Exchange prices	$ (37)	$ (15)	$ —	$—	$ (52)
Prices actively quoted	181	239	(9)	—	411
Prices provided by other external sources	(2)	(1)	(11)	18	4
Prices based on models and other valuation methods	(1)	16	23	4	42
Total	$141	$239	$ 3	$22	$405

SET has done significant business with Enron. Since Enron's financial difficulties, SET has unwound all of its trading positions with Enron. SET has been able to replace its former Enron level of activity with transactions with other parties, in some cases dealing directly with parties who would have been dealing with SET through Enron. In addition, SET is transacting business that previously might have gone to Enron and has hired some of Enron's former employees. At December 31, 2001, SET had receivables, net of the reserve for possible uncollected amounts, of less than $3 million.

SEMPRA ENERGY INTERNATIONAL

SEI develops, operates and invests in energy-infrastructure systems. SEI has interests in natural gas and/or electric transmission and distribution projects in Argentina, Chile, Mexico, Peru and the eastern United States, and is pursuing other projects, primarily in Mexico.

As noted above in "Investments," SEI increased its investment in Sodigas Pampeana S.A. and Sodigas Sur S.A. in 2000. These natural gas distribution companies serve 1.3 million customers in central and southern Argentina, respectively, and have a combined sendout of 650 million cubic feet per day. See further discussion at Note 3 of the notes to Consolidated Financial Statements.

In December 1999, Sempra Atlantic Gas (SAG), a subsidiary of SEI, was awarded a 25-year franchise by the government of Nova Scotia to build and operate a natural gas distribution system. In September 2001, due to new conditions required by the government of Nova Scotia, SAG notified the government that it intended to surrender its natural gas distribution franchise. SAG recorded an after-tax expense of $25 million related to the surrender of the franchise.

Net income from international operations in 2001 was $25 million compared to net income of $33 million and $2 million for 2000 and 1999, respectively. The decrease in net income for 2001 was primarily due to SAG's surrender of the natural gas franchise in Nova Scotia discussed above, partially offset by increased earnings at the Latin American subsidiaries. The increase in net income for 2000 was primarily due to the first full year of results from Luz and Energia, and improved operating results at Sodigas Pampeana S.A. and Sodigas Sur S.A.

Additional information concerning the company's international operations is provided in Note 3 of the notes to Consolidated Financial Statements.

SEMPRA ENERGY RESOURCES

SER develops, owns and operates power plants for the competitive market, and owns natural gas storage, production and transportation assets. SER is planning to develop 5,000 to 10,000 megawatts of generation within the next decade, primarily in the southwestern United States. SER is a 50-percent partner in El Dorado Energy, a 500-megawatt power plant located near Las Vegas, Nevada, which began commercial operation in 2000. In addition, SER has three power plants under construction. SER's share of El Dorado and the new plants will provide 2,400 megawatts of electricity when completed. See additional discussion regarding construction of these power plants in the "Investments" section above.

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 megawatts of power to the state. SER intends to deliver most of this electricity from its projected portfolio of plants in the western United States and Baja California, Mexico. Sales under the contract comprise more than two-thirds of the capacity referred to above. The company's ability to increase its earnings is significantly dependent on results to be provided by the DWR agreement. In accordance with the DWR contract, on June 1, 2001, SER began providing to the DWR 250 megawatts of capacity at prices discounted from normal contract prices. This electricity was supplied through market purchases and SER's share of the El Dorado generating facility. In accordance with the contract, sales to the DWR ceased from October 1, 2001 through March 31, 2002, the period during which expected demands for energy are lower due to cooler weather. Deliveries under the contract are scheduled to recommence on April 1, 2002 (without discounting) and end on September 30, 2011.

Subsequent to the state's signing of this contract and electricity-supply contracts with other vendors, various state officials have contended that the rates called for by the contracts are too high. These rates substantially exceed current spot-market prices for electricity, but are substantially lower than those prevailing at the time the contracts were signed. In February 2002, the CPUC and the California Electricity Oversight Board petitioned the Federal Energy Regulatory Commission to determine that the contracts do not provide just and reasonable rates, and to abrogate or reform the contracts. The company believes that its contract prices were fair, but has offered to renegotiate certain aspects of its contract (which would not affect the long-term profitability) in a manner mutually beneficial to SER and the state.

SER recorded a net loss of $27 million in 2001, compared to net income of $29 million and $5 million in 2000 and 1999, respectively. The decline in results for 2001 was primarily due to SER's sale of electricity to the State of California at a discounted price in the first phase of the long-term contract described above and the successful operations of the El Dorado power plant in 2000 when market prices for electricity were higher than in 2001 or 1999.

OTHER OPERATIONS

Sempra Energy's retail energy services, concentrated primarily in SES, provides integrated energy-related products and services to commercial, industrial, government, institutional and consumer markets. This includes owning and/or operating customer heating and cooling systems, providing energy efficient retrofitting and supplying energy commodities. The retail energy services' operations recorded net income of $2 million in 2001, compared to net losses of $23 million and $11 million in 2000 and 1999, respectively. The losses for 2000 and 1999 are primarily attributable to start-up costs, which continued in 2001 but were more than offset by the 2001 gain from the sale of Energy America as noted above.

In delivering electric and gas supplies to its commercial and industrial customers, SES hedges its price exposure through the use of exchange-traded and over-the-counter financial instruments. A summary of SES' unrealized revenues for trading activities for the year ended December 31, 2001 (in millions of dollars) follows:

Balance at beginning of year	$ 2
Additions	75
Realized	(8)
Balance at end of year	$69

The estimated fair values for SES' trading activities as of December 31, 2001, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	2002	2003 and 2004	2005 and 2006	Thereafter	Total fair value
Exchange prices	$ 3	$—	$—	$—	$ 3
Prices actively quoted	31	31	3	1	66
Total	$34	$31	$ 3	$ 1	$69

SEF invests as a limited partner in affordable-housing properties. SEF's portfolio includes 1,300 properties throughout the United States, Puerto Rico and the Virgin Islands. These investments are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also invests in alternative-fuel projects. SEF recorded net income of $28 million in each of 2001, 2000 and 1999. SEF's future investment policy is dependent on the company's future income tax position.

OTHER INCOME, INTEREST EXPENSE AND INCOME TAXES

Other Income

Other income, which primarily consists of interest income from short-term investments, equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, decreased to $90 million in 2001 from $127 million in 2000. The decrease was primarily due to the lower earnings from SER's investment in the El Dorado power plant, partially offset by higher interest income and $19 million from SDG&E's sale of its property in Blythe, California. Other income increased in 2000 to $127 million from $50 million in 1999, primarily due to improved equity earnings from El Dorado and from unconsolidated subsidiaries of SEI, and higher balancing-account interest.

Interest Expense

Interest expense for 2001 increased to $323 million from $286 million in 2000. The increase was primarily due to interest expense incurred on long-term debt issued in December of 2000 and June of 2001 as described in Note 5 of the notes to the Consolidated Financial Statements, and on higher short-term commercial paper borrowings in 2001. Interest expense increased to $286 million in 2000 from $229 million in 1999. The increase was primarily due to interest expense incurred on long-term debt issued in connection with the company's common stock repurchase, as described in Notes 5 and

12 of the notes to the Consolidated Financial Statements, and on short-term commercial paper borrowings made in 2000, offset by its 2000 expense associated with the surplus bond proceeds discussed in Note 5 of the notes to Consolidated Financial Statements. Interest rates on certain of the company's debt can vary with credit ratings, as described in Notes 4 and 5 of the notes to Consolidated Financial Statements.

Income Taxes

Income tax expense was $213 million, $270 million and $179 million for 2001, 2000 and 1999, respectively. The effective income tax rates were 29.1 percent, 38.6 percent and 31.2 percent for the same years. The decrease in income tax expense for 2001 compared to 2000 was primarily due to the favorable settlement of various tax issues and higher income tax credits, partially offset by the fact that any income tax benefits from certain losses outside the United States, primarily related to the SAG franchise surrender discussed above, are not yet recordable.

The increase in income tax expense for 2000 compared to 1999 was due to the increase in income before taxes and the fact that SDG&E made a charitable contribution to the San Diego Unified Port District in 1999 in connection with the sale thereto of its South Bay generating plant.

FACTORS INFLUENCING FUTURE PERFORMANCE

Base results of the company in the near future will depend primarily on the results of the California utilities, while earnings growth and volatility will result primarily from activities at SET, SEI, SER and other businesses. The factors influencing future performance are summarized below.

Electric Industry Restructuring and Electric Rates

In 1996, California enacted legislation restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates. During the transition period, utilities were allowed to charge frozen rates that were designed to be above current costs by amounts assumed to provide a reasonable opportunity to recover the above-market "stranded" costs of investments in electric-generating assets. The rate freeze was to end for each utility when it completed recovery of its stranded costs, but no later than March 31, 2002. SDG&E completed recovery of its stranded costs in June 1999 and, with its rates no longer frozen, SDG&E's overall rates became subject to fluctuation with the actual cost of electricity purchases.

Supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity costs beginning in mid-2000 and continuing into 2001. This caused SDG&E's monthly customer bills to be substantially higher than normal. In response, legislation enacted in September 2000 imposed a ceiling of 6.5 cents/kWh on the cost of electricity that SDG&E could pass on to its residential, small-commercial and lighting customers. The legislation provides for the future recovery of undercollections in a manner (not specified in the decision) intended to make SDG&E whole for the reasonable and prudent costs of procuring electricity. The undercollection, included as a noncurrent regulatory asset on the Consolidated Balance Sheets, amounted to $392 million at December 31, 2001.

As a result of the passage of Assembly Bill 1 in February 2001, the DWR began to purchase power from generators and marketers to supply a portion of the power requirements of the state's population that is served by IOUs. The DWR is now purchasing SDG&E's full net short position (the power needed by SDG&E's customers, other than that provided by SDG&E's nuclear generating facilities or its previously existing purchase power contracts). Therefore, increases in SDG&E's undercollections would result only from these contracts and interest, offset by nuclear generation, the cost of which is below the 6.5-cent customer rate cap. Any increases are not expected to be material.

On June 18, 2001, representatives of California Governor Davis, the DWR, Sempra Energy and SDG&E entered into the MOU, contemplating the implementation of a series of transactions and regulatory settlements and actions to resolve many of the issues affecting SDG&E and its customers arising out of the California energy crisis. The MOU contemplated, subject to requisite approvals of the CPUC, the elimination from SDG&E's rate-ceiling balancing account of the undercollected costs that otherwise would be recovered in future rates charged to SDG&E customers; settlement of reasonableness reviews, electricity purchase contract issues and various other regulatory matters affecting SDG&E. During 2001, the CPUC dealt with several of these regulatory settlements, including approval of a reduction of the rate-ceiling balancing account by the application thereto of overcollections in certain other balancing accounts totaling $70 million and approval of a delay in the effective date of revised base rates for the California utilities to 2004. In addition, the CPUC approved a $100 million reduction of the rate-ceiling balancing account in settlement of the reasonableness of SDG&E's electric procurement practices between July 1, 1999 through February 7, 2001.

In January 2002, the CPUC rejected the part of the MOU dealing with a settlement on electricity purchase contracts held by SDG&E. The MOU would have granted SDG&E ownership of its power sale profits in exchange for crediting $219 million to customers to offset the rate-ceiling balancing account. Instead, the CPUC asserted that all the profits associated with the energy purchase contracts should accrue to the benefit of customers. The CPUC estimated these profits as $363 million. The company believes the CPUC's calculation is incorrect and the CPUC has not explained to the company how it arrived at that amount. In addition, the company believes the CPUC's position is incorrect and has challenged the CPUC's original disallowance in the Court of Appeals. The court challenge was put on hold when the MOU was reached. SDG&E has now reactivated the case and has also filed a similar suit in federal court. Further discussion is included in Note 14 of the notes to Consolidated Financial Statements.

As discussed in Note 15 of the notes to Consolidated Financial Statements, the California utilities will make new cost of service filings at the end of 2002. Upon approval by the CPUC, new rates will be effective January 1, 2004. See additional discussion of these and related topics in Note 15 of the notes to Consolidated Financial Statements.

In September 2001, the CPUC suspended the ability of retail electricity customers to choose their power provider ("direct access") until at least the end of 2003 in order to improve the probability that enough revenue would be available to the DWR to cover the state's power purchases. The decision forbids new direct access contracts after September 20, 2001. In January 2002, a draft decision was issued modifying the direct access suspension decision, suspending direct access retroactively to July 1, 2001. This issue is on the CPUC's agenda for March 21, 2002. An unfavorable decision could adversely affect SES's contracts signed between July 1, 2001 and September 20, 2001. Any effect is not expected to be material to the company's financial position.

The CPUC is studying whether the incentive plan for the San Onofre Nuclear Generating Station (SONGS) should be terminated earlier than currently scheduled. This is discussed in Note 2 of the notes to Consolidated Financial Statements. The effects of an earlier termination are not yet determinable.

Natural Gas Restructuring and Gas Rates

On December 11, 2001, the CPUC issued a decision adopting the following provisions affecting the structure of the natural gas industry in California, some of which could introduce additional volatility into the earnings of the California utilities and other market participants: a system for shippers to hold firm, tradable rights to capacity on SoCalGas' major gas transmission lines with SoCalGas' shareholders at risk for whether market demand for these rights will cover the cost of these facilities; a further unbundling of SoCalGas' storage services, giving SoCalGas greater upward pricing flexibility (except for storage service for core customers) but with increased shareholder risk for whether market demand will cover storage costs; new balancing services including separate core and noncore balancing provisions; a reallocation among customer classes of the cost of interstate pipeline capacity held by SoCalGas and an unbundling of interstate capacity for gas marketers serving core customers; and the elimination of noncore customers' option to obtain gas supply service from the California utilities. The CPUC is still considering the schedule for implementation of these regulatory changes, but it is expected that most of the changes will be implemented during 2002.

Electric-Generation Assets

As discussed in "CASH FLOWS USED IN INVESTING ACTIVITIES" above, the company is involved in the development of several electric-generation projects. SER is a 50-percent joint partner in El Dorado Energy, a 500-megawatt power plant that was completed and began operations in May 2000. In addition, SER is constructing three power plants aggregating about 2,400 megawatts, which are expected to come on line in 2003. SER's share of these plants will be 2,100 megawatts. The company is in the permitting phase of four additional projects, also aggregating about 2,400 megawatts.

See additional discussion of these projects in "Investments," above and in Notes 3 and 13 of the notes to Consolidated Financial Statements.

Investments

As discussed in "CASH FLOWS USED IN INVESTING ACTIVITIES" above, the company has various investments and projects that will impact the company's future performance. These include, among other things, SEI's investments in the two Argentine natural gas utility holding companies, Energia, Luz, the natural gas pipelines in Baja California, and several natural gas distribution systems in Mexico; the recent purchase of Enron Metals Limited; and the investment in Atlantic Electric and Gas in the United Kingdom. See additional discussion of these investments and projects in Notes 3 and 13 of the notes to Consolidated Financial Statements. The devaluation of the Argentine peso, which is noted above and further described in Note 3 of the notes to Consolidated Financial Statements, is expected to have an adverse affect on future earnings of the Argentine operations, but the extent of the effect is not yet determinable.

Allowed Rate of Return

SoCalGas is authorized to earn a rate of return on rate base (ROR) of 9.49 percent and a rate of return on common equity (ROE) of 11.6 percent, the same as in 2001 and 2000. These rates will continue to be effective until the next periodic review by the CPUC unless interest-rate changes are large enough to trigger an automatic adjustment prior thereto. SDG&E is authorized to earn an 8.75 percent ROR and a 10.6 percent ROE, effective July 1, 1999, and remaining in effect through 2002. SDG&E is required to file an application by May 8, 2002, addressing ROE, ROR and capital structure for 2003. Either utility can earn more than the authorized rate by controlling costs below approved levels or by achieving favorable results in certain areas, such as various incentive mechanisms. In addition, earnings are affected by changes in sales volumes, except for the majority of SoCalGas' core sales.

Utility Integration

On September 20, 2001, the CPUC approved Sempra Energy's request to integrate the management teams of the California utilities. The decision retains the separate identities of each utility and is not a merger. Instead, utility integration is a reorganization that consolidates senior management functions of the two utilities and returns to the utilities a significant portion of shared support services currently provided by Sempra Energy's centralized corporate center. Once implementation is completed, the integration is expected to result in more efficient and effective operations.

In a related development, a CPUC draft decision would allow the California utilities to combine their natural gas procurement activities. The CPUC is scheduled to act on the draft decision at its April 4, 2002 meeting.

ENVIRONMENTAL MATTERS

The company's operations are subject to federal, state and local environmental laws and regulations governing such things as hazardous wastes, air and water quality, land use, solid-waste disposal, and the protection of wildlife.

Most of the environmental issues faced by the company occur at the California utilities. Utility costs to comply with environmental requirements are generally recovered in customer rates. Therefore, the likelihood of the company's financial position or results of operations being adversely affected in a significant manner is believed to be remote.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of the California utilities' manufactured-gas sites, cleanup at SDG&E's former fossil fuel power plants, cleanup of third-party waste-disposal sites used by the company, and mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS.

See further discussion of environmental matters in Note 13 of the notes to Consolidated Financial Statements.

MARKET RISK

Market risk is the risk of erosion of the company's cash flows, net income, asset values and equity due to adverse changes in prices for various commodities, and in interest and foreign-currency rates.

The company's policy is to use derivative financial instruments to reduce its exposure to fluctuations in interest rates, foreign-currency exchange rates and commodity prices. The company also uses and trades derivative financial instruments in its energy trading and marketing activities. Transactions involving these financial instruments are with firms believed to be credit worthy and major exchanges. The use of these instruments exposes the company to market and credit risks which, at times, may be concentrated with certain counterparties. Except for the ISO receivable referred to below, there were no unusual concentrations at December 31, 2001, that would indicate an unacceptable level of risk.

SET derives a substantial portion of its revenue from trading activities in natural gas, electricity, petroleum, petroleum products and other commodities. Profits are earned as SET acts as a dealer in structuring and executing transactions that assist its customers in managing their energy-price risk. In addition, SET may, on a limited basis, take positions in commodity markets based on the expectation of future market conditions. These positions include options, forwards, futures and swaps.

SES derives a portion of its revenue from delivering electric and gas supplies to its commercial and industrial customers. Such contracts are hedged to preserve margin and carry minimal market risk. Exchange-traded and over-the-counter instruments are used to hedge contracts.

The California utilities use energy derivatives to manage natural gas price risk associated with servicing their load requirements. In addition, they make limited use of natural gas derivatives for trading purposes. These instruments can include forward contracts, futures, swaps, options and other contracts. In the case of both price-risk management and trading activities, the use of derivative financial instruments by the California utilities is subject to certain limitations imposed by company policy and regulatory requirements. See the continuing discussion below and Note 10 of the notes to Consolidated Financial Statements for further information regarding the use of energy derivatives by the California utilities.

The company has adopted corporate-wide policies governing its market-risk management and trading activities. An Energy Risk Management Oversight Committee, consisting of senior officers, oversees company-wide energy risk management activities and monitors the results of trading activities to ensure compliance with the company's stated energy-risk management and trading policies. In addition, all affiliates have groups that monitor energy-price risk management and trading activities independently from the groups responsible for creating or actively managing these risks.

Along with other tools, the company uses Value at Risk (VaR) to measure its exposure to market risk. VaR is an estimate of the potential loss on a position or portfolio of positions over a specified holding period, based on normal market conditions and within a given statistical confidence interval. The company has adopted the variance/covariance methodology in its calculation of VaR, and uses both the 95-percent and 99-percent confidence interval. A one-day holding period is used for SET. Historical volatilities and correlations between instruments and positions are used in the calculation. Following is a summary of the company's trading VaR profile in millions of dollars:

	95%	99%
SET at December 31, 2001	$6.9	$ 9.7
SET 2001 average	6.1	8.6
SET at December 31, 2000	7.2	10.2
SET 2000 average	6.2	8.8

Additional information is provided in Note 10 of the notes to Consolidated Financial Statements.

The following discussion of the company's primary market-risk exposures as of December 31, 2001, includes a discussion of how these exposures are managed.

Commodity-Price Risk

Market risk related to physical commodities is based upon potential fluctuations in the prices and basis of certain commodities. The company's market risk is impacted by changes in volatility and liquidity in the markets in which these commodities or related financial instruments are traded. The company's regulated and unregulated affiliates are exposed, in varying degrees, to price risk primarily in the natural gas, petroleum and electricity markets. The company's policy is to manage this risk within a framework that considers the unique markets, and operating and regulatory environments of each affiliate.

Sempra Energy Trading

Because SET derives a substantial portion of its revenue from trading activities in natural gas, petroleum and electricity, it is exposed to price volatility in the domestic and international natural gas, petroleum and electricity markets. SET conducts these activities within a structured and disciplined risk management and control framework that is based on clearly communicated policies and procedures, position limits, active and ongoing management monitoring and oversight, clearly defined roles and responsibilities, and daily risk measurement and reporting.

California Utilities

With respect to the California utilities, market risk exposure is limited due to CPUC authorized rate recovery of commodity purchase, sale and storage activity. However, the California utilities may, at times, be exposed to market risk as a result of activities under SDG&E's gas PBR or SoCalGas' Gas Cost Incentive Mechanism, which are discussed in Note 15 of the notes to Consolidated Financial Statements. They manage their risk within the parameters of the company's market-risk management and trading framework. As of December 31, 2001, the total VaR of the California utilities' natural gas positions was not material.

Interest-Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its fixed-rate long-term debt. The company has historically funded utility operations through long-term debt issues with fixed interest rates and these interest rates are recovered in utility rates. With the restructuring of the regulatory process, the CPUC has permitted greater flexibility within the debt-management process. As a result, recent debt offerings have been selected with short-term maturities to take advantage of yield curves, or have used a combination of fixed-rate and floating-rate debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures when appropriate, based upon market conditions.

At December 31, 2001, the California utilities had $1.7 billion of fixed-rate debt and $0.3 billion of variable-rate debt. Interest on fixed-rate utility debt is fully recovered in rates on a historical cost basis and interest in variable-rate debt is provided for in rates on a forecasted basis. At December 31, 2001, utility fixed-rate debt had a one-year VaR of $394 million and utility variable-rate debt had a one-year VaR of $37 million. Non-utility debt (fixed-rate and variable-rate) was $1.6 billion at December 31, 2001, with a one-year VaR of $150 million.

At December 31, 2001, the notional amount of interest-rate swap transactions totaled $720 million. See Notes 5 and 10 of the notes to Consolidated Financial Statements for further information regarding these swap transactions.

Credit Risk

Credit risk relates to the risk of loss that would be incurred as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The company avoids concentration of counterparties and maintains credit policies with regard to counterparties that management believes significantly minimize overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. At December 31, 2001, SET was due approximately $100 million from the ISO for which the company believes adequate reserves have been recorded.

The company monitors credit risk through a credit-approval process and the assignment and monitoring of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry.

The company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. The company would be exposed to interest-rate fluctuations on the underlying debt should other parties to the agreement not perform. See the "Interest-Rate Risk" section above for additional information regarding the company's use of interest-rate swap agreements.

Foreign-Currency-Rate Risk

Foreign-currency-rate risk exists by the nature of the company's global operations. The company has investments in entities whose functional currency is not the U.S. dollar, which exposes the company to foreign exchange movements, primarily in Latin American currencies. As a result of the devaluation of the Argentine peso, in December 2001 SEI adjusted its investment in two unconsolidated Argentine subsidiaries downward by $155 million, which is included in "other comprehensive income (loss)." As the Argentine peso has been significantly devalued and will float freely in the foreign exchange market, the company recognizes that both income and cash flows associated with the investments are likely to be reduced; however, the company believes that they will remain sufficiently positive to support the carrying values of the investments. The company does not anticipate adverse developments that would change this view.

In appropriate instances, the company may attempt to limit its exposure to changing foreign-exchange rates through both operational and financial market actions. Financial actions may include entering into forward, option and swap contracts to hedge existing exposures, firm commitments and anticipated transactions. As of December 31, 2001, the company had not entered into any such arrangements.

CRITICAL ACCOUNTING POLICIES

The company's most significant accounting policies are described in Note 2 of the notes to Consolidated Financial Statements. The most critical policies are Statement of Financial Accounting Standards (SFAS) 71 "Accounting for the Effects of Certain Types of Regulation," SFAS 133 and SFAS 138 "Accounting for Derivative Instruments and Hedging Activities" and "Accounting for Certain Derivative Instruments and Certain Hedging Activities," (see below) and Issue No. 98-10 of the Emerging Issues Task Force of the Financial Accounting Standards Board "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." All of these policies are mandatory under generally accepted accounting principles and the regulations of the Securities and Exchange Commission. Each of these policies has a material effect on the timing of revenue and expense recognition for significant company operations.

In connection with the application of these and other accounting policies, the company makes estimates and judgments about various matters. The most significant of these involve the calculation of fair values, and the collectibility of regulatory and other assets. As discussed elsewhere herein, the company uses exchange quotations or other third-party pricing to estimate fair values whenever possible. When no such data is available, it uses internally developed models or other techniques. The assumed collectibility of regulatory assets considers legal and regulatory decisions involving the specific items or similar items. The assumed collectibility of other assets considers the nature of the item, the enforceability of contracts where applicable, the creditworthiness of other parties and other factors.

NEW ACCOUNTING STANDARDS

Effective January 1, 2001, the company adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." As amended, SFAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value and recognize changes in the fair value of derivatives in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

The company utilizes derivative financial instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative financial instruments are comprised of futures, forwards, swaps, options and long-term delivery contracts.

These contracts allow the company to predict with greater certainty the effective prices to be received and, in the case of the California utilities, the prices to be charged to their customers.

Upon adoption of SFAS 133 on January 1, 2001, the company is classifying its forward contracts as follows:

Normal Purchase and Sales: These forward contracts are excluded from the requirements of SFAS No. 133. The realized gains and losses on these contracts are reflected in the income statement at the contract settlement date. The contracts that generally qualify as normal purchases and sales are long-term contracts that are settled by physical delivery.

Cash Flow Hedges: The unrealized gains and losses related to these forward contracts are included in accumulated other comprehensive income, a component of shareholders' equity, and reflected in the Statements of Consolidated Income when the corresponding hedged transaction is settled.

Electric and Gas Purchases and Sales: The unrealized gains and losses related to these forward contracts, as they relate to the California utilities, are reflected on the balance sheet as regulatory assets and liabilities, to the extent derivative gains and losses will be recoverable or payable in future rates.

If gains and losses at the California utilities are not recoverable or payable through future rates, the California utilities will apply hedge accounting if certain criteria are met.

In instances where hedge accounting is applied to energy derivatives, cash flow hedge accounting is elected and, accordingly, changes in fair values of the derivatives are included in other comprehensive income and reflected in the Statements of Consolidated Income when the corresponding hedged transaction is settled. The effect on other comprehensive income for the year ended December 31, 2001 was not material. In instances where energy derivatives do not qualify for hedge accounting, gains and losses are recorded in the Statements of Consolidated Income.

The adoption of this new standard on January 1, 2001 did not have a material impact on the company's earnings. However, $1.1 billion in current assets, $1.1 billion in noncurrent assets, $6 million in current liabilities, and $238 million in noncurrent liabilities were recorded in the Consolidated Balance Sheets as fixed-priced contracts and other derivatives as of January 1, 2001. Due to the regulatory environment in which the California utilities operate, regulatory assets and liabilities were established to the extent that derivative gains and losses are recoverable or payable through future rates. As such, $1.1 billion in current regulatory liabilities, $1.1 billion in noncurrent regulatory liabilities, $5 million in current regulatory assets, and $238 million in noncurrent regulatory assets were recorded in the Consolidated Balance Sheets as of January 1, 2001. See Note 10 of the notes to Consolidated Financial Statements for additional information on the effects of SFAS 133 on the financial statements at December 31, 2001. The ongoing effects will depend on future market conditions and the company's hedging activities.

In July 2001, the Financial Accounting Standards Board (FASB) issued three statements, SFAS 141 "Business Combinations," SFAS 142 "Goodwill and Other Intangible Assets" and SFAS 143 "Accounting for Asset Retirement Obligations."

SFAS 141 requires the use of the purchase method of accounting for all business combinations initiated after June 30, 2001. The pooling-of-interest method is eliminated. It also specifies the types of acquired intangible assets that are required to be recognized and reported separately from goodwill.

SFAS 142 provides guidance on how to account for goodwill and other intangible assets after an acquisition is complete, and is effective for fiscal years that start after December 15, 2001. SFAS 142 calls for amortization of goodwill to cease and requires goodwill and certain other intangibles to be tested for impairment at least annually. Amortization of goodwill, including the company's share of amounts recorded by unconsolidated subsidiaries, was $24 million, $35 million and $32 million in 2001, 2000 and 1999, respectively. The company does not expect a material impact on its earnings resulting from any impairment of goodwill.

SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of a long-lived asset, such as nuclear plants. It requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. SFAS 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002.

Upon adoption of SFAS 143, the company estimates it would record an addition of $468 million to utility plant representing the company's share of the SONGS estimated future decommissioning costs, and a corresponding retirement obligation liability of $468 million. The nuclear decommissioning trusts balance of $526 million at December 31, 2001 represents amounts collected for future decommissioning costs and has a corresponding offset in accumulated depreciation. Any difference between the amount of capitalized cost that would have been recorded and depreciated and the amounts collected in the nuclear decommissioning trusts will be recorded as a regulatory asset or liability. Additional information on SONGS decommissioning is included in Note 6 of the notes to Consolidated Financial Statements. Except for SONGS, the company has not yet determined the effect of SFAS 143 on its financial statements.

In August 2001, the FASB issued SFAS 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" that replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS 144 applies to all long-lived assets, including discontinued operations. SFAS 144 requires that those long-lived assets classified as held for sale be measured at the lower of carrying amount or fair value less cost to sell. Discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for fiscal years beginning after December 15, 2001. The company has not yet determined the effect of SFAS 144 on its financial statements.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains statements that are not historical fact and constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The words "estimates," "believes," "expects," "anticipates," "plans," "intends," "may," "would" and "should" or similar expressions, or discussions of strategy or of plans are intended to identify forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future results may differ materially from those expressed in these forward-looking statements.

Forward-looking statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others, local, regional, national and international economic, competitive, political, legislative and regulatory conditions and developments; actions by the CPUC, the California Legislature, the DWR, and the FERC; the financial condition of other investor-owned utilities; capital market conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; weather conditions and conservation efforts; business, regulatory and legal decisions; the pace of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this annual report and other reports filed by the company from time to time with the Securities and Exchange Commission.

FIVE YEAR SUMMARY

At December 31 or for the Years Ended December 31

(Dollars in millions except per-share amounts)	**2001**	2000	1999	1998	1997
OPERATING REVENUES					
California utilities:					
Gas	**$ 4,371**	$ 3,305	$ 2,911	$ 2,752	$ 2,964
Electric	**1,627**	2,184	1,818	1,865	1,769
Other	**2,031**	1,548	631	364	336
Total	**$ 8,029**	$ 7,037	$ 5,360	$ 4,981	$ 5,069
Operating income	**$ 993**	$ 884	$ 763	$ 626	$ 906
Net income	**$ 518**	$ 429	$ 394	$ 294	$ 432
Net income per common share:					
Basic	**$ 2.54**	$ 2.06	$ 1.66	$ 1.24	$ 1.83
Diluted	**$ 2.52**	$ 2.06	$ 1.66	$ 1.24	$ 1.82
Dividends declared per common share	**$ 1.00**	$ 1.00	$ 1.56	$ 1.56	$ 1.27
Pretax income/revenue	**9.1%**	9.9%	10.7%	8.7%	14.5%
Return on common equity	**19.5%**	15.7%	13.4%	10.0%	14.7%
Effective income tax rate	**29.1%**	38.6%	31.2%	31.9%	41.1%
Dividend payout ratio:					
Basic	**39.4%**	48.5%	94.0%	125.8%	69.4%
Diluted	**39.7%**	48.5%	94.0%	125.8%	69.8%
Price range of common shares	**$ 28.61-17.31**	$ 24.88-16.19	$ 26.00-17.13	$ 29.31-23.75	*
AT DECEMBER 31					
Current assets	**$ 4,808**	$ 6,525	$ 3,015	$ 2,458	$ 2,761
Total assets	**$15,156**	$15,540	$11,124	$ 10,456	$10,756
Current liabilities	**$ 5,524**	$ 7,490	$ 3,236	$ 2,466	$ 2,211
Long-term debt (excludes current portion)	**$ 3,436**	$ 3,268	$ 2,902	$ 2,795	$ 3,175
Shareholders’ equity	**$ 2,692**	$ 2,494	$ 2,986	$ 2,913	$ 2,959
Common shares outstanding (in millions)	**204.5**	201.9	237.4	237.0	235.6
Book value per common share	**$ 13.16**	$ 12.35	$ 12.58	$ 12.29	$ 12.56
Price/earnings ratio	**9.7**	11.3	10.5	20.5	*
Number of meters (in thousands):					
Natural gas	**5,878**	5,807	5,726	5,639	5,551
Electricity	**1,258**	1,238	1,218	1,192	1,178

*Not presented as the formation of Sempra Energy was not completed until June 26, 1998

Statement of Management's Responsibility for Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with generally accepted accounting principles. The integrity and objectivity of these financial statements and the other financial information in the Financial Report, including the estimates and judgments on which they are based, are the responsibility of management. The financial statements have been audited by Deloitte & Touche LLP, independent auditors appointed by the board of directors. Their report is shown on the next page. Management has made available to Deloitte & Touche LLP all of the company's financial records and related data, as well as the minutes of shareholders' and directors' meetings.

Management maintains a system of internal control which it believes is adequate to provide reasonable, but not absolute, assurance that assets are properly safeguarded, that transactions are executed in accordance with management's authorization and are properly recorded and that the accounting records may be relied on for the preparation of the consolidated financial statements, and for the prevention and detection of fraudulent financial reporting. The concept of reasonable assurance recognizes that the cost of a system of internal control should not exceed the benefits derived and that management makes estimates and judgments of these cost/benefit factors.

Management monitors the system of internal control for compliance through its own review and an internal auditing program, which independently assesses the effectiveness of the internal controls. The company's independent auditors also consider certain elements of internal controls in order to determine their audit procedures for the purpose of expressing an opinion on the company's financial statements. Management considers the recommendations of the internal auditors and independent auditors concerning the company's system of internal controls and takes appropriate actions. Management believes that the company's system of internal control is adequate to provide reasonable assurance that the accompanying financial statements present fairly the company's financial position and results of operations.

Management also recognizes its responsibility for fostering a strong ethical climate so that the company's affairs are conducted according to the highest standards of personal and corporate conduct. This responsibility is characterized and reflected in the company's code of corporate conduct, which is publicized throughout the company. The company maintains a systematic program to assess compliance with this policy.

The board of directors has an audit committee, composed of independent directors, to assist in fulfilling its oversight responsibilities for management's conduct of the company's financial reporting processes. The audit committee meets regularly to discuss financial reporting, internal controls and auditing matters with management, the company's internal auditors and independent auditors, and recommends to the board of directors any appropriate response to those discussions. The audit committee recommends for approval by the full board the appointment of the independent auditors. The independent auditors and the internal auditors periodically meet alone with the audit committee and have free access to the audit committee at any time.

Neal E. Schmale
Executive Vice President and
Chief Financial Officer

Frank H. Ault
Senior Vice President and Controller

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Sempra Energy:

We have audited the accompanying consolidated balance sheets of Sempra Energy and subsidiaries (the "company") as of December 31, 2001 and 2000, and the related statements of consolidated income, cash flows and changes in shareholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly, in all material respects, the financial position of Sempra Energy and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

San Diego, California
February 4, 2002 (February 21, 2002 as to Note 14 and March 5, 2002 as to Note 15)

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SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions, except per share amounts)	Years Ended December 31, **2001**	2000	1999
OPERATING REVENUES			
California utilities:			
Natural gas	**$ 4,371**	$ 3,305	$ 2,911
Electric	**1,627**	2,184	1,818
Other	**2,031**	1,548	631
Total	**8,029**	7,037	5,360
OPERATING EXPENSES			
Cost of natural gas distributed	**2,549**	1,599	1,164
Electric fuel and net purchased power	**733**	1,326	536
Other operating expenses	**2,985**	2,485	1,837
Depreciation and amortization	**579**	563	879
Franchise payments and other taxes	**190**	180	181
Total	**7,036**	6,153	4,597
Operating income	**993**	884	763
Other income — net	**90**	127	50
Preferred dividends of subsidiaries	**(11)**	(11)	(11)
Trust preferred distributions by subsidiary	**(18)**	(15)	—
Interest expense	**(323)**	(286)	(229)
Income before income taxes	**731**	699	573
Income taxes	**213**	270	179
Net income	**$ 518**	$ 429	$ 394
Weighted-average number of shares outstanding:			
Basic*	**203,593**	208,155	237,245
Diluted*	**205,338**	208,345	237,553
Net income per share of common stock (basic)	**$ 2.54**	$ 2.06	$ 1.66
Net income per share of common stock (diluted)	**$ 2.52**	$ 2.06	$ 1.66
Common dividends declared per share	**$ 1.00**	$ 1.00	$ 1.56

* In thousands of shares

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, **2001**	2000
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 605**	$ 637
Accounts receivable — trade	**660**	994
Accounts and notes receivable — other	**130**	213
Due from unconsolidated affiliates	**57**	—
Income taxes receivable	**98**	24
Energy trading assets	**2,575**	4,083
Fixed-price contracts and other derivatives	**57**	—
Regulatory assets arising from fixed-price contracts and other derivatives	**193**	—
Other regulatory assets	**73**	100
Inventories	**289**	342
Other	**71**	132
Total current assets	**4,808**	6,525
Investments and other assets:		
Fixed-price contracts and other derivatives	**27**	—
Regulatory assets arising from fixed-price contracts and other derivatives	**830**	—
Other regulatory assets	**1,005**	1,001
Nuclear-decommissioning trusts	**526**	543
Investments	**1,169**	1,288
Sundry	**574**	457
Total investments and other assets	**4,131**	3,289
Property, plant and equipment:		
Property, plant and equipment	**12,806**	11,889
Less accumulated depreciation and amortization	**(6,589)**	(6,163)
Total property, plant and equipment — net	**6,217**	5,726
Total assets	**$15,156**	$15,540

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, **2001**	2000
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	**$ 875**	$ 568
Accounts payable — trade	**702**	1,162
Accounts payable — other	**114**	117
Deferred income taxes	**70**	110
Energy trading liabilities	**1,793**	3,619
Dividends and interest payable	**139**	124
Regulatory balancing accounts - net	**660**	832
Regulatory liabilities	**19**	—
Fixed-price contracts and other derivatives	**195**	—
Current portion of long-term debt	**242**	368
Other	**715**	590
Total current liabilities	**5,524**	7,490
Long-term debt	**3,436**	3,268
Deferred credits and other liabilities:		
Due to unconsolidated affiliate	**160**	—
Customer advances for construction	**67**	56
Post-retirement benefits other than pensions	**145**	152
Deferred income taxes	**847**	752
Deferred investment tax credits	**95**	101
Fixed-price contracts and other derivatives	**835**	—
Regulatory liabilities	**86**	—
Deferred credits and other liabilities	**865**	823
Total deferred credits and other liabilities	**3,100**	1,884
Preferred stock of subsidiaries	**204**	204
Mandatorily redeemable trust preferred securities	**200**	200
Commitments and contingent liabilities (Note 13)		
SHAREHOLDERS' EQUITY		
Common stock (204,475,362 and 201,927,524 shares outstanding at December 31, 2001 and 2000, respectively)	**1,495**	1,420
Retained earnings	**1,475**	1,162
Deferred compensation relating to ESOP	**(36)**	(39)
Accumulated other comprehensive income (loss)	**(242)**	(49)
Total shareholders' equity	**2,692**	2,494
Total liabilities and shareholders' equity	**$15,156**	$15,540

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years Ended December 31 **2001**	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 518**	$ 429	$ 394
Adjustments to reconcile net income to net cash provided provided by operating activities:			
Depreciation and amortization	**579**	563	879
Customer refunds paid	**(127)**	(628)	—
Portion of depreciation arising from sales of generating plants	**—**	—	(303)
Application of balancing accounts to stranded costs	**—**	—	(66)
Deferred income taxes and investment tax credits	**106**	258	86
Equity in (income) losses of unconsolidated affiliates	**(12)**	(62)	5
Gain on sale of Energy America	**(29)**	—	—
Loss from surrender of Nova Scotia franchise	**30**	—	—
Gain on sale of assets	**(14)**	—	—
Changes in other assets	**(214)**	22	(56)
Changes in other liabilities	**98**	(108)	(3)
Net changes in other working capital components	**(203)**	408	252
Net cash provided by operating activities	**732**	882	1,188
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	**(1,068)**	(759)	(589)
Investments and acquisitions of unconsolidated affiliates	**(111)**	(243)	(639)
Dividends received from unconsolidated affiliates	**80**	30	—
Net proceeds from sales of assets	**128**	24	466
Loan to affiliate	**(57)**	—	—
Other	**(11)**	24	(27)
Net cash used in investing activities	**(1,039)**	(924)	(789)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common stock dividends	**(203)**	(244)	(368)
Repurchase of common stock	**(1)**	(725)	—
Issuances of common stock	**41**	12	3
Issuance of trust preferred securities	**—**	200	—
Issuances of long-term debt	**675**	813	160
Payments on long-term debt	**(681)**	(238)	(270)
Loan from affiliate	**160**	—	—
Increase in short-term debt — net	**310**	386	139
Other	**(26)**	(12)	—
Net cash provided by (used in) financing activities	**275**	192	(336)
Increase (decrease) in cash and cash equivalents	**(32)**	150	63
Cash and cash equivalents, January 1	**637**	487	424
Cash and cash equivalents, December 31	**$ 605**	$ 637	$ 487

See notes to Consolidated Financial Statements.

	Years Ended December 31,		
	2001	2000	1999
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, and debt due within one year)			
Accounts and notes receivable	**$ 353**	$(655)	$ 188
Net trading assets	**(362)**	(290)	(73)
Income taxes — net	**(121)**	120	(171)
Inventories	**33**	(97)	(2)
Regulatory balancing accounts	**46**	522	303
Regulatory assets and liabilities	**39**	(2)	(2)
Other current assets	**69**	(84)	(21)
Accounts payable	**(302)**	733	25
Other current liabilities	**42**	161	5
Net change in other working capital components	**$(203)**	$ 408	$ 252
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	**$ 302**	$ 291	$ 274
Income tax payments, net of refunds	**$ 138**	$ 104	$ 168
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Liabilities assumed for real estate investments	**$ —**	$ —	$ 34

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years Ended December 31, 2001, 2000 and 1999

(Dollars in millions)	Comprehensive Income	Common Stock	Retained Earnings	Deferred Compensation Relating to ESOP	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 1998		$1,883	$1,075	$ (45)	$ —	$2,913
Net income	$394		394			394
Comprehensive income adjustments:						
Foreign-currency translation losses	(42)				(42)	(42)
Available-for-sale securities	10				10	10
Pension	(7)				(7)	(7)
Comprehensive income	$355					
Common stock dividends declared			(368)			(368)
Quasi-reorganization adjustment (Note 2)		80				80
Issuances of common stock		2				2
Long-term incentive plan		1				1
Common stock released from ESOP				3		3
Balance at December 31, 1999		1,966	1,101	(42)	(39)	2,986
Net income	$429		429			429
Comprehensive income adjustments:						
Foreign-currency translation losses	(2)				(2)	(2)
Available-for-sale securities	(10)				(10)	(10)
Pension	2				2	2
Comprehensive income	$419					
Common stock dividends declared			(201)			(201)
Issuances of common stock		11				11
Repurchase of common stock		(558)	(167)			(725)
Long-term incentive plan		1				1
Common stock released from ESOP				3		3
Balance at December 31, 2000		**1,420**	**1,162**	**(39)**	**(49)**	**2,494**
Net income	**$518**		**518**			**518**
Comprehensive income adjustments:						
Foreign-currency translation losses (Note 2)	**(186)**				**(186)**	**(186)**
Pension	**(8)**				**(8)**	**(8)**
Other	**1**				**1**	**1**
Comprehensive income	**$325**					
Common stock dividends declared			**(205)**			**(205)**
Quasi-reorganization adjustment (Note 2)		**35**				**35**
Issuances of common stock		**41**				**41**
Repurchase of common stock		**(1)**				**(1)**
Common stock released from ESOP				**3**		**3**
Balance at December 31, 2001		**$1,495**	**$1,475**	**$ (36)**	**$ (242)**	**$2,692**

See notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. BUSINESS COMBINATION

Sempra Energy (the company) was formed as a holding company for Enova Corporation (Enova) and Pacific Enterprises (PE) in connection with a business combination of Enova and PE that was completed on June 26, 1998. As a result of the combination, each outstanding share of common stock of Enova was converted into one share of common stock of Sempra Energy, and each outstanding share of common stock of PE was converted into 1.5038 shares of common stock of Sempra Energy.

The Consolidated Financial Statements are those of the company and its subsidiaries and give effect to the business combination using the pooling-of-interests method and, therefore, are presented as if the companies were combined during all periods included therein.

NOTE 2. SIGNIFICANT ACCOUNTING POLICIES

Effects of Regulation

The accounting policies of the company's principal utility subsidiaries, San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the California utilities), conform with generally accepted accounting principles for regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

SDG&E and SoCalGas prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," under which a regulated utility records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. Regulatory liabilities represent future reductions in rates for amounts due to customers. To the extent that portions of the utility operations cease to be subject to SFAS No. 71, or recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets and liabilities would be written off. In addition, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," affects utility plant and regulatory assets such that a loss must be recognized whenever a regulator excludes all or part of an asset's cost from rate base. The application of SFAS No. 121 continues to be evaluated in connection with industry restructuring. Information concerning regulatory assets and liabilities is described below in "Revenues", "Regulatory Balancing Accounts," and "Regulatory Assets and Liabilities," and industry restructuring is described in Notes 14 and 15.

Revenues

Revenues from the California utilities are derived from deliveries of electricity and natural gas to customers and changes in related regulatory balancing accounts. Revenues for electricity and natural gas sales and services are generally recorded under the accrual method and these revenues are recognized upon delivery. The portion of SDG&E's electric commodity that is procured for its customers by the California Department of Water Resources (DWR) is not included in SDG&E's revenues or costs. PX/ISO power revenues have been netted against purchased-power expense to avoid double-counting as SDG&E sells power into the PX/ISO and then purchases power therefrom. Natural gas storage contract revenues are accrued on a monthly basis and reflect reservation, storage and injection charges in accordance with negotiated agreements, which have one-year to three-year terms. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

Operating costs of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are recovered through a performance incentive pricing plan which allows SDG&E to receive approximately 4 cents per kilowatt-hour (kWh) through 2003. Any differences between these costs and the incentive price affect net income. This is intended to make the units more competitive with other sources. As part of the CPUC's study of retained generation by all of California's investor-owned electric utilities (IOUs) a draft decision proposes that the incentive plan be terminated effective December 31, 2001 even though California law provides for its continuance through 2003. An alternative draft decision proposes that the incentive plan continues as scheduled. The matter is on the CPUC's agenda for its March 21, 2002 meeting.

Additional information concerning utility revenue recognition is discussed below under "Regulatory Balancing Accounts" and "Regulatory Assets and Liabilities."

Sempra Energy Trading (SET) derives a substantial portion of its revenues from market making and trading activities, as a principal, in natural gas, electricity, petroleum and other commodities, for which it quotes bid and asked prices to end users and other market makers. Principal transaction revenues are recognized on a trade-date basis, and include realized gains and losses, and the net change in unrealized gains and losses measured at current market value. SET also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. In addition, it takes positions in energy markets based on the expectation of future market conditions. These positions include options, forwards, futures, physical commodities and swaps. Options, which are either exchange-traded or directly negotiated between counterparties, provide the holder with the right to buy from or sell to the other party an agreed amount of commodity at a specified price within a specified period or at a specified time.

As a writer of options, SET generally receives an option premium and then manages the risk of an unfavorable change in the value of the underlying commodity by entering into related transactions or by other means. Forward and future transactions are contracts for delayed delivery of commodities in which the counterparty agrees to make or take delivery at a specified price. Commodity swap transactions may involve the exchange of fixed and floating payment obligations without the exchange of the underlying commodity. These financial instruments represent contracts with counterparties whereby payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. For the year ended December 31, 2001, substantially all of SET's derivative transactions were held for trading and marketing purposes and were recorded at current market value.

Revenues at Sempra Energy Solutions (SES) are derived from integrated energy-related products and services to commercial, industrial, government, institutional and consumer markets. Energy supply revenues from natural gas and electricity commodity sales are recognized on a current market value basis and include realized gains and losses and the net change in unrealized gains and losses measured at fair value. Revenues on construction projects are recognized during the construction period using the percentage-of-completion method, and revenues from other operating and maintenance service contracts are recorded under the accrual method and recognized as service is rendered.

The consolidated subsidiaries of Sempra Energy International (SEI) which operate in Mexico recognize revenue similarly to the California utilities, except that SFAS 71 is not applicable due to the different regulatory environment. The balance of SEI's revenues and most of the revenues of Sempra Energy Resources (SER) consist of their share of the income of their unconsolidated subsidiaries.

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2001, represent net payables (payables net of assets) of $85 million and $575 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2000, were net payables of $465 million and $367 million for SoCalGas and SDG&E, respectively.

Balancing accounts provide a mechanism for charging utility customers the exact amount incurred for certain costs, primarily commodity costs. As a result of California's electric-restructuring law, fluctuations in certain costs and consumption levels that had been balanced now affect earnings from electric operations. In addition, fluctuations in certain costs and consumption levels affect earnings from the California utilities' natural gas operations. Additional information on regulatory matters is included in Notes 14 and 15.

Regulatory Assets and Liabilities

In accordance with the accounting principles of SFAS 71 for rate-regulated enterprises, the company records regulatory assets (which represent probable future revenues 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). They are amortized over the periods in which the costs are recovered from or refunded to customers in regulatory revenues.

Regulatory assets (liabilities) as of December 31 consist of (dollars in millions):

	2001	2000
SDG&E		
Fixed-price contracts and other derivatives	**$ 760**	$ —
Recapture of temporary discount*	**409**	474
Undercollected electric commodity cost	**392**	352
Deferred taxes recoverable in rates	**162**	140
Unamortized loss on retirement of debt-net	**52**	57
Employee benefit costs	**39**	35
Other	**26**	7
Total	**1,840**	1,065
SoCalGas		
Environmental remediation	**55**	58
Fixed-price contracts and other derivatives	**257**	—
Unamortized loss on retirement of debt-net	**41**	36
Deferred taxes refundable in rates	**(158)**	(100)
Employee benefit costs	**(132)**	(60)
Other	**5**	6
Total	**68**	(60)
PE—Employee benefit costs	**88**	96
Total PE consolidated	**156**	36
Total	**$ 1,996**	$1,101

* In connection with electric industry restructuring, which is described in Note 14, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2004.

Net regulatory assets are recorded on the Consolidated Balance Sheets at December 31 as follows (dollars in millions):

	2001	2000
Current regulatory assets	**$ 266**	$ 100
Noncurrent regulatory assets	**1,835**	1,001
Current regulatory liabilities	**(19)**	—
Noncurrent regulatory liabilities	**(86)**	—
Total	**$1,996**	$1,101

All assets earn a return or the cash has not yet been expended and the assets are offset by liabilities that do not incur a carrying cost.

Trading Instruments

Trading assets and trading liabilities are recorded on a trade-date basis and adjusted daily to current market value. They include option premiums paid and received; and unrealized gains and losses from exchange-traded futures and options, over-the-counter (OTC) swaps, forwards, physical commodities and options. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable master netting arrangement.

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at current market value based on current closing exchange quotations. Commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from current dealer quotations and underlying commodity-exchange quotations. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates. For long-dated forward transactions, where there are no dealer or exchange quotations, current market values are derived using internally developed valuation methodologies based on available market information. Where market rates are not quoted, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ significantly from realized values. Changes in market values are recorded in the calculation of net income.

Allowance for Doubtful Accounts

The allowance for doubtful accounts was $45 million, $34 million and $19 million at December 31, 2001, 2000, and 1999, respectively. The company recorded a provision for doubtful accounts of $36 million, $32 million and $11 million in 2001, 2000 and 1999, respectively.

Loans Due From Unconsolidated Affiliates

In December 2001, SEI issued two U.S. dollar denominated loans totaling $35 million and $22 million to its affiliates Camuzzi Gas Pampeana S. A. and Camuzzi Gas del Sur S. A., respectively. These loans have variable interest rates (8.863% at December 31, 2001) and are due on December 11, 2002.

Inventories

At December 31, 2001, inventory included natural gas and fuel oil of $233 million, and materials and supplies of $56 million. The corresponding balances at December 31, 2000 were $265 million and $77 million, respectively. SET's portion ($165 million and $197 million at December 31, 2001 and 2000, respectively) of the natural gas and fuel oil are carried at fair market value. Natural gas and fuel oil at the California utilities ($68 million at both December 31, 2001 and 2000) are valued by the last-in first-out (LIFO) method. When the California utilities' inventory is consumed, differences between this LIFO valuation and replacement cost will be reflected in customer rates. Materials and supplies at the California utilities are generally valued at the lower of average cost or market.

Property, Plant and Equipment

Property, plant and equipment primarily represents the buildings, equipment and other facilities used by the California utilities to provide natural gas and electric utility service.

The cost of utility plant includes labor, materials, contract services and related items, and an allowance for funds used during construction (AFUDC). The cost of most retired depreciable utility plant, plus removal costs minus salvage value, is charged to accumulated depreciation. Information regarding electric industry restructuring and its effect on utility plant is included in Note 14. Property, plant and equipment balances by major functional categories were as follows:

	Property, Plant and Equipment at December 31		Depreciation rates for years ended December 31		
(Dollars in billions)	**2001**	2000	**2001**	2000	1999
California utilities:					
Natural gas operations	**$ 7.4**	$ 7.2	**4.25%**	4.29%	4.32%
Electric distribution	**2.9**	2.7	**4.67%**	4.67%	4.69%
Electric transmission	**0.8**	0.8	**3.19%**	3.21%	3.50%
Other electric	**0.4**	0.4	**8.46%**	8.33%	8.21%
Total	**11.5**	11.1			
Other operations	**1.3**	0.8	**various**	various	various
Total	**$12.8**	$11.9			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $4.2 billion and $2.1 billion, respectively, at December 31, 2001, and were $4.1 billion and $2.0 billion, respectively, at December 31, 2000. Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. See Note 14 for discussion of the sale of generation facilities and industry restructuring. Maintenance costs are expensed as incurred.

AFUDC, which represents the cost of funds used to finance the construction of utility plant, is added to the cost of utility plant. AFUDC also increases income, partly as an offset to interest charges and partly as a component of other income, shown in the Statements of Consolidated Income, although it is not a current source of cash. AFUDC amounted to $6 million, $4 million and $4 million for 2001, 2000 and 1999, respectively. Total interest amounts capitalized, including AFUDC and the impact of SER's construction projects, were $17 million, $7 million and $5 million for 2001, 2000 and 1999, respectively.

Long-Lived Assets

In accordance with SFAS 121, “Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of,” the company periodically evaluates whether events or circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets. Impairment occurs when the estimated future undiscounted cash flows exceed the carrying amount of the assets. If that comparison indicates that the assets’ carrying value may be permanently impaired, such potential impairment is measured based on the difference between the carrying amount and the fair value of the assets based on quoted market prices or, if market prices are not available, on the estimated discounted cash flows. This calculation is performed at the lowest level for which separately identifiable cash flows exist.

Nuclear-Decommissioning Liability

At December 31, 2001 and 2000, deferred credits and other liabilities include $151 million and $162 million, respectively, of accumulated decommissioning costs associated with SDG&E’s interest in SONGS Unit 1, which was permanently shut down in 1992. The corresponding liability for SONGS Units 2 and 3 decommissioning (included in accumulated depreciation and amortization) is $375 million and $381 million at December 31, 2001 and 2000, respectively. Additional information on SONGS decommissioning costs is included in Note 6.

Foreign Currency Translation

The assets and liabilities of the company’s foreign operations are generally translated into U.S. dollars at current exchange rates, and revenues and expenses are translated at average exchange rates for the year. Resulting translation adjustments do not enter into the calculation of net income or retained earnings, but are reflected in accumulated other comprehensive income, a component of shareholders’ equity which is described below. Foreign currency transaction gains and losses are included in consolidated net income. In December 2001, to reflect the devaluation in the Argentine peso, the functional currency of the company’s Argentine operations, SEI adjusted its investment in two Argentine natural gas utility holding companies downward by $155 million. The adjustment is included in the calculation of comprehensive income. Additional information concerning these investments is described in Note 3.

Comprehensive Income

Comprehensive income includes all changes, except those resulting from investments by owners and distributions to owners, in the equity of a business enterprise from transactions and other events, including foreign-currency translation adjustments, minimum pension liability adjustments, unrealized gains and losses on marketable securities that are classified as available-for-sale, and certain hedging activities. The components of other comprehensive income are shown in the Statements of Consolidated Changes in Shareholders’ Equity.

Quasi-Reorganization

In 1993, PE divested its merchandising operations and most of its oil and gas exploration and production business. In connection with the divestitures, PE effected a quasi-reorganization for financial reporting purposes as of December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization, including various income-tax issues, have been favorably resolved. Excess liabilities of $35 million and $80 million resulting from the favorable resolution of these issues were restored to shareholders’ equity in December 2001 and November 1999, respectively, but did not affect the calculation of net income. The remaining liabilities will be resolved in future years. Management believes the provisions established for these matters are adequate.

Use of Estimates in the Preparation of the Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results can differ significantly from those estimates.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with maturities of three months or less at the date of purchase.

Basis of Presentation

Certain prior-year amounts have been reclassified to conform to the current year's presentation.

New Accounting Standards

Effective January 1, 2001, the company adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." As amended, SFAS 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value and recognize changes in the fair value of derivatives in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

The company utilizes derivative financial instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative financial instruments include futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received and, in the case of the California utilities, the prices to be charged to their customers.

Upon adoption of SFAS 133 on January 1, 2001, the company classifies its forward contracts as follows:

Normal Purchase and Sales: These forward contracts are excluded from the requirements of SFAS No. 133. The realized gains and losses on these contracts are reflected in the income statement at the contract settlement date. The contracts that generally qualify as normal purchases and sales are long-term contracts that are settled by physical delivery.

Cash Flow Hedges: The unrealized gains and losses related to these forward contracts will be included in accumulated other comprehensive income, a component of shareholders' equity, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled.

Electric and Gas Purchases and Sales: The unrealized gains and losses related to these forward contracts, as they relate to the California utilities, are reflected on the balance sheet as regulatory assets and liabilities, to the extent derivative gains and losses will be recoverable or payable in future rates.

If gains and losses at the California utilities are not recoverable or payable through future rates, the California utilities will apply hedge accounting if certain criteria are met.

In instances where hedge accounting is applied to energy derivatives, cash flow hedge accounting is elected and, accordingly, changes in fair values of the derivatives are included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. The effect on other comprehensive income for the year ended December 31, 2001 was not material. In instances where energy derivatives do not qualify for hedge accounting, gains and losses are recorded in the Statements of Consolidated Income.

The adoption of this new standard on January 1, 2001, did not have a material effect on the company's earnings. However, $1.1 billion in current assets, $1.1 billion in noncurrent assets, $6 million in current liabilities and $238 million in noncurrent liabilities were recorded in the Consolidated Balance Sheets as fixed-priced contracts and other derivatives as of January 1, 2001. Due to the regulatory environment in which the California utilities operate, regulatory assets and liabilities were established to the extent that derivative gains and losses are recoverable or payable through future rates. As such, $1.1 billion in current regulatory liabilities, $1.1 billion in noncurrent regulatory liabilities, $5 million in current regulatory assets and $238 million in noncurrent regulatory assets were recorded in the Consolidated Balance Sheets as of January 1, 2001. See Note 10 for additional information on the effects of SFAS 133 on the financial statements at December 31, 2001. The ongoing effects will depend on future market conditions and the company's hedging activities.

In July 2001, the Financial Accounting Standards Board (FASB) issued three statements, SFAS 141 "Business Combinations," SFAS 142 "Goodwill and Other Intangible Assets" and SFAS 143 "Accounting for Asset Retirement Obligations."

SFAS 141 requires the use of the purchase method of accounting for all business combinations initiated after June 30, 2001. The pooling-of-interest method is eliminated. It also specifies the types of acquired intangible assets that are required to be recognized and reported separately from goodwill.

SFAS 142 provides guidance on how to account for goodwill and other intangible assets after an acquisition is complete, and is effective for fiscal years that start after December 15, 2001. SFAS 142 calls for amortization of goodwill to cease and requires goodwill and certain other intangibles to be tested for impairment at least annually. Included in the Consolidated Balance Sheets at December 31, 2001 were $172 million of goodwill related to consolidated subsidiaries (included in sundry assets) and $248 million of goodwill related to unconsolidated subsidiaries (included in investments). Amortization of goodwill, including the company's share of amounts recorded by unconsolidated subsidiaries, was $24 million, $35 million and $32 million in 2001, 2000, and 1999, respectively. The company does not expect a material impact on its earnings resulting from any impairment of goodwill.

SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of a long-lived asset, such as nuclear plants. It requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. SFAS 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002.

Upon adoption of SFAS 143, the company estimates it would record an addition of $468 million to utility plant representing the company's share of SONGS estimated future decommissioning costs, and a corresponding retirement obligation liability of $468 million. The nuclear decommissioning trusts balance of $526 million at December 31, 2001 represents amounts collected for future decommissioning costs and has a corresponding offset in accumulated depreciation. Any difference between the amount of capitalized cost that would have been recorded and depreciated and the amounts collected in the nuclear decommissioning trusts will be recorded as a regulatory asset or liability. Additional information on SONGS decommissioning is included in Note 6. Except for SONGS, the company has not yet determined the effect of SFAS 143 on its Consolidated Balance Sheets, but has determined that it will not have a material effect on its Statements of Consolidated Income.

In August 2001, the FASB issued SFAS 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" that replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS 144 applies to all long-lived assets, including discontinued operations. SFAS 144 requires that those long-lived assets classified as held for sale be measured at the lower of carrying amount (cost less accumulated depreciation) or fair value less cost to sell. Discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for fiscal years beginning after December 15, 2001. The adoption of SFAS 144 will not have a material effect on the company's financial statements.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments in which the company has an interest of twenty to fifty percent are accounted for under the equity method. The company's pro rata shares of the subsidiaries' net assets are included under the caption "Investments" on the Consolidated Balance Sheets, and are adjusted for the company's share of each investee's earnings, dividends and foreign currency translation effects. Earnings are recorded as equity earnings on the Statements of Consolidated Income within the caption "Other income — net." In addition, the company had approximately $30 million of investments accounted for by the cost method (at December 31, 2001 and 2000). The company's investments in unconsolidated subsidiaries accounted for by the equity method are summarized as follows:

	Investment at December 31	
(in millions)	**2001**	2000
Chilquinta Energia (including Luz del Sur)	**$ 476**	$ 511
Sodigas Pampeana and Sodigas Sur	**140**	290
Elk Hills power project	**133**	—
El Dorado power project	**57**	85
Sempra Energy Financial housing partnerships	**290**	346
Sempra Energy Financial alternative fuel partnerships	**27**	19
Other	**13**	3
Total Investment	**1,136**	1,254
Equity in net assets	**(888)**	(974)
Cost in excess of equity in net assets	**$ 248**	$ 280

Through December 31, 2001, the excess of the investment over the related equity in net assets had been amortized over various periods, primarily forty years (see Note 2). Descriptive information concerning each of these subsidiaries follows.

Sempra Energy International

In June 1999, SEI and PSEG Global (PSEG) each purchased a 50-percent interest in Chilquinta Energia S.A. (Energia), a Chilean electric utility. SEI invested $260 million for the purchase of stock and refinanced $160 million of Energia's long-term debt outstanding. In September 1999, SEI and PSEG completed their acquisition of 47.5 percent of the outstanding shares of Luz del Sur S.A.A. (Luz), a Peruvian electric utility. SEI's share of the transaction was $108 million in cash. Combined with the 37 percent already owned through Energia, the companies' total joint ownership of Luz increased to 84.5 percent.

In October 2000, SEI increased its existing investment in two Argentine natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.) from 21.5 percent to 43 percent. Shortly after December 31, 2001, the Argentine peso, the functional currency of the company's Argentine operations, was devalued and will now float freely in the foreign exchange market. As a result, SEI adjusted its investment in the Sodigas companies downward by $155 million. This did not affect net income, but is included in Other Comprehensive Income.

Sempra Energy Resources

In December 2000, SER obtained approvals from the appropriate state agencies to construct the Elk Hills Power Project (Elk Hills), a $410 million, 570-megawatt power plant near Bakersfield, California. Elk Hills is being developed in a joint venture with Occidental Energy Ventures Corporation (Occidental). Information concerning litigation with Occidental is provided in Note 13.

In 2000, El Dorado Energy, a 50/50 partnership between SER and Reliant Energy Power Generation, completed construction of a $280 million, 500-megawatt merchant power plant near Las Vegas, Nevada.

Sempra Energy Financial (SEF)

SEF invests as a limited partner in 1,300 affordable-housing projects throughout the United States, Puerto Rico and the Virgin Islands. These investments are accounted for in accordance with Issue No. 94-1 of the Emerging Issues Task Force of the Financial Accounting Standards Board, "Accounting for Tax Benefits Resulting from Investments in Affordable Housing Projects." These investments are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also invests in alternative-fuel projects. SEF's future investment policy is dependent on the company's future income tax position.

Sempra Energy Solutions

In August 2000, SES purchased Connectiv Thermal Systems' 50-percent interests in Atlantic-Pacific Las Vegas and Atlantic-Pacific Glendale for $40 million, thereby acquiring full ownership of these on-site energy management companies, resulting in their becoming consolidated subsidiaries.

NOTE 4. SHORT-TERM BORROWINGS

At December 31, 2001, Sempra Energy Global Enterprises (Global), the parent company for most of Sempra Energy's subsidiaries other than the California utilities, had a $1.2 billion syndicated revolving line of credit guaranteed by Sempra Energy. The revolving credit commitment expires in September 2002, at which time then outstanding borrowings may be converted to a one-year term loan. The agreement requires Sempra Energy to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent. Under this ratio Sempra Energy and its subsidiaries could have issued in excess of $2 billion of additional debt at December 31, 2001.

Borrowings under the agreement would bear interest at rates varying with market rates and Sempra Energy's credit rating. Global's line of credit was unused at December 31, 2001, and is available to support commercial paper and variable-rate long-term debt. Global had $705 million and $401 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2001 and 2000, respectively.

At December 31, 2001, SDG&E had $250 million of revolving lines of credit, which is available to support commercial paper and variable-rate long-term debt. The revolving credit commitments on $50 million and $200 million of these lines expire in July 2002 and August 2002, respectively, at which time then outstanding borrowings may be converted into term loans of one and two years, respectively. Borrowings under the lines would bear interest at rates varying with market rates and SDG&E’s credit rating. These revolving lines of credit were unused at December 31, 2001 and 2000.

At December 31, 2001, SoCalGas had a $170 million syndicated revolving line of credit, which is available to support commercial paper. Borrowings under the agreement, which expires on May 26, 2002, would bear interest at rates varying with market rates and SoCalGas’ credit rating. The agreement requires SoCalGas to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent. At December 31, 2001, SoCalGas had $50 million of commercial paper outstanding. The revolving line of credit was unused at December 31, 2001 and 2000.

At December 31, 2001, SER had a syndicated $400 million, three-year revolving line of credit, guaranteed by Sempra Energy, primarily to finance power plant and gas pipeline construction projects. The agreement requires that Sempra Energy maintains a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent. SER’s line of credit was unused at December 31, 2001. This agreement expires in August 2004 and borrowings bear interest at rates varying with market rates and Sempra Energy’s credit rating. In January 2002, SER borrowed $200 million of the credit line to fund its construction activities.

At December 31, 2001, PE had a $500 million two-year revolving line of credit, guaranteed by Sempra Energy, for the purpose of providing loans to Global. The revolving credit commitment expires in April 2003, at which time then outstanding borrowings may be converted into a two-year term loan. Borrowings would be subject to mandatory prepayment should PE’s issuer credit rating cease to be at least BBB- by Standard & Poors, should SoCalGas’ unsecured long-term credit ratings cease to be at least BBB by S&P and Baa2 by Moody’s, should Sempra Energy’s or SoCalgas’ debt-to-total capitalization ratios (as defined in the agreement) exceed 65 percent, or should there be a change in law materially and adversely affecting the ability of SoCalGas to pay dividends or make distributions to PE. Borrowings would bear interest at rates varying with market rates and the amount of outstanding borrowings. PE's line of credit was unused at December 31, 2001.

At December 31, 2001, SET had $548 million in various uncommitted lines of credit that are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy’s credit rating. SET had $120 million and $165 million in short-term borrowings outstanding at December 31, 2001 and 2000, respectively. SET also had $167 million of letters of credit outstanding against these lines at December 31, 2001.

The company’s weighted average interest rate for short-term borrowings outstanding at December 31, 2001 and 2000 was 2.18% and 6.69%, respectively.

NOTE 5. LONG-TERM DEBT

December 31 (Dollars in millions)	**2001**	2000
First-mortgage bonds		
7.625% June 15, 2002	**$ 28**	$ 28
6.875% August 15, 2002	**100**	100
5.75% November 15, 2003	**100**	100
6.8% June 1, 2015	**14**	14
5.9% June 1, 2018	**68**	68
5.9% to 6.400% September 1, 2018	**176**	176
6.1% September 1, 2019	**35**	35
Variable rates (2% to 2.4% at December 31, 2001) payable September 1, 2020	**58**	58
5.85% June 1, 2021	**60**	60
8.5% April 1, 2022	**10**	10
7.375% March 1, 2023	**100**	100
7.5% June 15, 2023	**125**	125
Variable rates (1.95% at December 31, 2001) payable November 1, 2025	**175**	175
6.4% and 7% December 1, 2027	**225**	165
8.75% October 1, 2021	**—**	150
Total	**1,274**	1,364
Unsecured long-term debt		
5.9% June 1, 2014	**130**	130
Variable rates (1.75% at December 31, 2001) payable July 1, 2021	**39**	39
Variable rates (1.5% at December 31, 2001) payable December 1, 2021	**60**	60
6.75% March 1, 2023	**25**	25
5.67% January 18, 2028	**75**	75
6.375% May 14, 2006	**8**	8
6.375% October 29, 2001	**—**	120
Other variable-rate debt	**27**	10
Total	**364**	467
Rate-reduction bonds, various rates, payable annually through 2007 (6.15% to 6.37% at December 31, 2001)	**395**	461
Debt incurred to acquire limited partnerships, secured by real estate, at 6.97% to 9.35% payable annually through 2009	**187**	233
Notes payable at 6.95% payable in 2005	**300**	300
Notes payable at 7.95% payable in 2010	**500**	500
Notes payable at variable rates after a fixed-to-floating rate swap (3.19% to 3.23% at December 31, 2001) payable in 2004	**500**	—
Employee Stock Ownership Plan		
Bonds at 7.375% payable in November 2014	**82**	82
Bonds at variable rates (2.39% at December 31, 2001) payable in November 2014	**46**	48
Variable rate debt (10.2% at December 31,2000)	**—**	160
Capitalized leases	**14**	37
Market value adjustments for interest rate swaps — net	**22**	—
Total	**3,684**	3,652
Less:		
Current portion of long-term debt	**242**	368
Unamortized discount on long-term debt	**6**	16
	248	384
Total	**$3,436**	$3,268

Excluding capital leases, which are described in Note 13, and market value adjustments for interest-rate swaps, maturities of long-term debt are $235 million in 2002, $277 million in 2003, $600 million in 2004, $394 million in 2005, $90 million in 2006 and $2.1 billion thereafter. Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by revolving lines of credit (which are generally renewed upon expiration and which are described in Note 4), it is assumed the bonds will be held to maturity for purposes of determining the maturities listed above. Interest rates on the $800 million of debt payable in 2005 and 2010 can vary with the company's credit ratings.

First-mortgage Bonds

The first-mortgage bonds were issued by the California utilities and are secured by a lien on their respective utility plant. The California utilities may issue additional first-mortgage bonds upon compliance with the provisions of their bond indentures, which require, among other things, the satisfaction of pro forma earnings-coverage tests on first-mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds. The most restrictive of these tests (the property test) would have permitted the issuance, subject to CPUC authorization, of an additional $2.5 billion of first-mortgage bonds at December 31, 2001.

During the first quarter of 2001, SDG&E remarketed $150 million of variable-rate first-mortgage bonds for a five-year term at a fixed rate of 7 percent. At SDG&E's option, the bonds may be remarketed at a fixed or floating rate at December 1, 2005, the expiration of the fixed term.

In November 2001, SoCalGas called its $150 million 8.75% million first-mortgage bonds at a premium of 3.59 percent.

On December 11, 2001, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on its $175 million 6.875% first-mortgage bonds for a floating rate. Additional information is provided under "Interest-Rate Swaps" below.

Callable Bonds

At the company's option, certain bonds may be called at a premium, including $157 million of variable-rate bonds that are callable at various dates in 2002. Of the company's remaining callable bonds, $203 million are callable in 2002, $666 million in 2003, $25 million in 2004, $105 million in 2005 and $8 million in 2006.

Rate-Reduction Bonds

In December 1997, $658 million of rate-reduction bonds were issued on behalf of SDG&E at an average interest rate of 6.26 percent. These bonds were issued to facilitate the 10-percent rate reduction mandated by California's electric-restructuring law, which is described in Note 14. These bonds are being repaid over 10 years by SDG&E's residential and small-commercial customers via a charge on their electricity bills. These bonds are secured by the revenue streams collected from customers and are not secured by, or payable from, utility assets.

The sizes of the rate-reduction bond issuances were set so as to make the IOUs neutral as to the 10-percent rate reduction, and were based on a four-year period to recover stranded costs. Because SDG&E recovered its stranded costs in only 18 months (due to the greater-than-anticipated plant-sale proceeds), the bond sale proceeds were greater than needed. Accordingly, during the third quarter of 2000, SDG&E returned to its customers $388 million of surplus bond proceeds in accordance with a June 8, 2000 CPUC decision. The bonds and their repayment schedule are not affected by this refund.

Unsecured Long-term Debt

In February 2001, SDG&E remarketed $25 million of variable-rate unsecured bonds as 6.75 percent fixed-rate debt for a three-year term. At SDG&E's option, the bonds may be remarketed at a fixed or floating rate at February 29, 2004, the expiration of the fixed term. In October 2001, SoCalGas repaid $120 million of 6.38-percent medium-term notes upon maturity. In June 2001, the company issued $500 million of three-year notes due July 1, 2004 at an interest rate of 6.8 percent. Sempra Energy has a fixed-to-floating rate swap on these notes. (See discussion under "Interest-Rate Swaps" below.)

In February 2000, the company issued $500 million of long-term 7.95 percent notes due in 2010 to partially finance the self-tender offer described in Note 12. In December 2000, the company issued an additional $300 million in long-term notes due in 2005 in order to reduce short-term debt. The notes bear interest at 6.95 percent, which is subject to change based on the company's credit ratings. In July 2000, SoCalGas repaid $30 million of 8.75 percent medium-term notes upon maturity.

Debt of Employee Stock Ownership Plan (ESOP) and Trust (Trust)

The Trust covers substantially all of SoCalGas' employees and is used to fund part of the retirement savings plan. The Trust was assumed by Sempra Energy on October 1, 1999, and participation in the ESOP was expanded to include employees of Sempra Energy and some of its unregulated affiliates effective January 1, 2000. In November 1999, the $130 million ESOP debt was refinanced using 15-year notes with a variable interest rate. The notes are repriced weekly and subject to repurchase by the company at the holder's option, depending on market demand. Subsequently, in June 2001, utilizing the term option provisions of the notes, $82 million of the notes were remarketed at a fixed rate of 7.375% for three years. The variable interest rate and weekly repricing resume in May 2004. In September 2001, ESOP debt was reduced by $2.5 million when 40,000 shares of company common stock were released from the Trust in order to fund the employer contribution to the company savings plan. Additional information on the company savings plan is included in Note 8. Interest on ESOP debt amounted to $6 million in 2001, $9 million in 2000 and $6 million in 1999. Dividends used for debt service amounted to $3 million in 2001, $3 million in 2000 and $5 million in 1999.

Interest-Rate Swaps

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. At December 31, 2001, the company had three such agreements. SDG&E has an interest-rate swap agreement that matures in 2002 and effectively fixes the interest rate on $45 million of variable-rate underlying debt at 5.4 percent. This floating-to-fixed-rate swap does not qualify for hedge accounting and, therefore, the gains and losses associated with the change in fair value are recorded in the Statements of Consolidated Income. For the year ended December 31, 2001, the effect on income was a $1 million loss. Although this financial instrument does not meet the hedge accounting criteria of SFAS 133, it continues to be effective in achieving the risk management objectives for which it was intended.

The remaining two agreements are fixed-to-floating-rate swaps. Sempra Energy has entered into a fixed-to-floating-rate swap on $500 million of underlying debt which matures in 2004 and effectively causes the interest rate on the debt to vary at a weighted-average rate of LIBOR plus 1.329 percent. On December 11, 2001, SoCalGas executed a cancelable-call interest-rate swap, exchanging its fixed-rate obligation of 6.875 percent on its $175 million first-mortgage bonds for a floating rate of LIBOR plus 4 basis points. The transaction may be cancelled every 5 years by either party by payment of the mark-to-market value, or may be cancelled by the counterparty at any time the bonds are callable, by payment to SoCalGas of the applicable call premium on the bonds. The company believes both swaps are fully effective in their purpose of converting the fixed rate stated in the debt to a floating rate and the swaps meet the criteria for accounting under the short-cut method defined in SFAS No. 133 for fair value hedges of debt instruments. Accordingly, a market value adjustment to long-term debt of $22 million was recorded at December 31, 2001 to reflect, without affecting net income or other comprehensive income, the favorable economic consequences (as measured at December 31, 2001) of having entered into the swap transactions. See additional discussion of interest rate swaps in Note 10.

Foreign-Currency Hedges

The company's primary objective with respect to currency risk is to reduce net income volatility that would otherwise occur due to exchange-rate fluctuations.

Sempra Energy's net investment in its Latin American operating companies and the resulting cash flows are partially protected against normal exchange-rate fluctuations by rate-setting mechanisms which are intended to compensate for local inflation and currency exchange-rate fluctuations. In addition to establishing such tariff-based protections, the company hedges material cross-currency transactions and net-income exposure through various means, including financial instruments and short-term investments.

Because the company does not hedge its net investment in foreign countries, it is susceptible to volatility in other comprehensive income, as occurred in the year ended December 31, 2001 when Argentina decoupled its peso from the U.S. dollar, as discussed in Notes 2 and 3.

See additional discussion of foreign-currency hedges in Note 10.

Loans Due to Affiliates

In March 2001, SEI refinanced $160 million of long-term notes through its unconsolidated affiliate Chilquinta Energia Finance, LLC. At December 31, 2001 long-term notes payable to affiliates include $60 million at 6.47 percent due April 1, 2008 and $100 million at 6.62 percent due April 1 2011. The loans are secured by SEI's investments in Energia and Luz.

Financial Covenants

The California utilities' first-mortgage bond indentures require the satisfaction of certain bond interest coverage ratios and the availability of sufficient mortgaged property to issue additional first-mortgage bonds, but do not restrict other indebtedness. Note 4 discusses the financial covenants applicable to short-term debt.

NOTE 6. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2001, are:

Project (Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20%	88%
Utility plant in service	$70	$219
Accumulated depreciation and amortization	$41	$127
Construction work in progress	$ 4	$ 1

Each of the company and the other owners hold its interest as undivided interest as tenants in common. Each owner is responsible for financing its share of each project and participates in decisions concerning operations and capital expenditures.

The company's share of operating expenses is included in the Statements of Consolidated Income. The amounts specified above for SONGS include nuclear production, transmission and other facilities. Certain substation equipment at SONGS is wholly owned by the company.

SONGS Decommissioning

Objectives, work scope and procedures for the future dismantling and decontamination of the SONGS units must meet the requirements of the Nuclear Regulatory Commission, the Environmental Protection Agency, the CPUC and other regulatory bodies.

The company's share of decommissioning costs for the SONGS units has been estimated to be $468 million in 2001 dollars, based on escalation of a cost study completed in 1998. Cost studies are updated every three years and approved by the CPUC. The next such update is scheduled to be filed with the CPUC in the first half of 2002. Rate recovery of decommissioning costs is allowed until the time that the costs are fully recovered, and is subject to adjustment every three years based on costs allowed by regulators. The amount accrued each year is currently being collected in rates. Collections are authorized to continue until 2013, but may be extended until 2022 upon approval by the CPUC. This amount is considered sufficient to cover the company's share of future decommissioning costs. Payments to the nuclear decommissioning trusts (described below under "Nuclear Decommissioning Trusts") are expected to continue until sufficient funds have been collected to fully decommission SONGS, which is not expected to occur before 2022.

Unit 1 was permanently shut down in 1992 and physical decommissioning began in January 2000. Several structures, foundations and equipment have been dismantled and removed. Preparations have been made for the remaining major work to be performed in 2002 and beyond. That work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities (both nuclear and non-nuclear components), decontamination of the site and construction of an on-site storage facility for Unit 1 spent fuel. These activities are expected to be completed by 2008.

The amounts collected in rates are invested in externally managed trust funds (described below under "Nuclear Decommissioning Trusts"). The securities held by the trusts are considered available for sale and the trust assets are shown on the Consolidated Balance Sheets at market value. These values reflect unrealized gains of $122 million and $158 million at December 31, 2001, and 2000, respectively, with the offsetting credit recorded to accumulated depreciation and decommissioning on the Consolidated Balance Sheets.

In July 2001, the FASB approved SFAS No. 143 "Accounting for Asset Retirement Obligations," which requires entities to record the fair value of a liability that results from the acquisition, construction, development and/or the normal operation of long-lived assets, such as nuclear power plants. Information concerning the estimated effect on the company's financial statements is provided in Note 2. See further discussion regarding SONGS in Notes 13 and 14.

Nuclear Decommissioning Trusts

SDG&E has a Nonqualified Nuclear Decommissioning Trust and a Qualified Nuclear Decommissioning Trust. CPUC guidelines prohibit investments in derivatives and securities of Sempra Energy or related companies. They also establish maximum amounts for investments in equity securities (50 percent of the qualified trust and 60 percent of the nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of the trusts shall be invested passively.

At December 31, 2001 and 2000, trust assets were allocated as follows (dollars in millions):

	Qualified Trust		Nonqualified Trust	
	2001	2000	**2001**	2000
Domestic equity	**$144**	$143	**$48**	$57
Foreign equity	**76**	78	**—**	—
Total equity	**220**	221	**48**	57
Total fixed income	**225**	228	**33**	37
Total	**$445**	$449	**$81**	$94

The decommissioning cost studies referred to above determine the appropriate level of contributions to be collected in utility-customer rates to ensure adequate funding at the decommissioning date. Customer contribution amounts are determined by estimates of after-tax investment returns, decommissioning costs and escalation rates for decommissioning costs. Lower actual investment returns or higher actual decommissioning costs would result in an increase in customer contributions.

NOTE 7. INCOME TAXES

The reconciliation of the statutory federal income tax rate to the effective income tax rate is as follows:

For the years ended December 31	**2001**	2000	1999
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Depreciation	**5.9**	6.7	7.0
State income taxes — net of federal income tax benefit	**6.4**	6.6	6.6
Tax credits	**(13.7)**	(13.0)	(14.9)
Income from unconsolidated foreign subsidiaries	**(3.0)**	(1.8)	(1.0)
Other — net	**(1.5)**	5.1	(1.5)
Effective income tax rate	**29.1%**	38.6%	31.2%

The components of income tax expense are as follows:

(Dollars in millions)	**2001**	2000	1999
Current:			
Federal	**$ 36**	$ (8)	$ 72
State	**60**	(5)	21
Foreign	**11**	25	—
Total	**107**	12	93
Deferred:			
Federal	**104**	207	79
State	**1**	57	15
Foreign	**7**	(1)	—
Total	**112**	263	94
Deferred investment tax credits	**(6)**	(5)	(8)
Total income tax expense	**$213**	$270	$179

Accumulated deferred income taxes at December 31 result from the following:

(Dollars in millions)	**2001**	2000
DEFERRED TAX LIABILITIES:		
Differences in financial and tax bases of utility plant	**$ 664**	$ 730
Balancing accounts and other regulatory assets	**489**	521
Partnership income	**37**	49
Other	**287**	276
Total deferred tax liabilities	**1,477**	1,576
DEFERRED TAX ASSETS:		
Investment tax credits	**65**	71
General business tax credit carryforward	**24**	113
Comprehensive Settlement	**9**	26
Postretirement benefits	**36**	39
Other deferred liabilities	**174**	143
Restructuring costs	**40**	51
Other	**212**	271
Total deferred tax assets	**560**	714
Net deferred income tax liability	**$ 917**	$ 862

The net deferred income tax liability is recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	**2001**	2000
Current liability	**$ 70**	$110
Noncurrent liability	**847**	752
Total	**$917**	$862

The general business tax credit carryforward expires in 2021.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($182 million at December 31, 2001), which are expected to be reinvested outside the U.S. indefinitely. It is not possible to predict the amount of U.S. income taxes that might be payable if these earnings were eventually repatriated.

NOTE 8. EMPLOYEE BENEFIT PLANS

The information presented below covers the plans of the company and its principal subsidiaries.

Pension and Other Postretirement Benefits

The company sponsors several qualified and nonqualified pension plans and other postretirement benefit plans for its employees. Effective March 1, 1999, the Pacific Enterprises Pension Plan merged with the Sempra Energy Cash Balance Plan.

During 2001, SDG&E participated in a voluntary separation program. As a result, the company recorded a $13 million special termination benefit, a $1 million curtailment cost and a $19 million settlement gain.

During 2000, Sempra Energy and most of its subsidiaries participated in another voluntary separation program. As a result, the company recorded a $56 million special termination benefit, a $2 million curtailment credit and a $26 million settlement gain.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and the fair value of assets over the two years, and a statement of the funded status as of each year end:

(Dollars in millions)	Pension Benefits 2001	Pension Benefits 2000	Other Postretirement Benefits 2001	Other Postretirement Benefits 2000
WEIGHTED-AVERAGE ASSUMPTIONS AS OF DECEMBER 31:				
Discount rate	**7.25%**	7.25%(1)	**7.25%**	7.25%
Expected return on plan assets	**8.00%**	8.00%	**7.85%**	7.85%
Rate of compensation increase	**5.00%**	5.00%	**5.00%**	5.00%
Cost trend of covered health-care charges	**—**	—	**7.25%(2)**	7.50%(2)
CHANGE IN BENEFIT OBLIGATION:				
Net benefit obligation at January 1	**$2,027**	$1,962	**$ 551**	$ 555
Service cost	**49**	41	**11**	11
Interest cost	**141**	153	**41**	37
Actuarial (gain) loss	**(27)**	114	**13**	(37)
Curtailments	**(7)**	(7)	**—**	5
Settlements	**1**	2	**—**	—
Special termination benefits	**13**	54	**—**	2
Benefits paid	**(187)**	(292)	**(26)**	(22)
Net benefit obligation at December 31	**2,010**	2,027	**590**	551
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	**2,910**	3,427	**515**	548
Actual return on plan assets	**(277)**	(247)	**(37)**	(25)
Employer contributions	**3**	22	**17**	14
Benefits paid	**(187)**	(292)	**(26)**	(22)
Fair value of plan assets at December 31	**2,449**	2,910	**469**	515
Plan assets net of benefit obligation at December 31	**439**	883	**(121)**	(36)
Unrecognized net actuarial gain	**(426)**	(945)	**(14)**	(106)
Unrecognized prior service cost	**49**	55	**(10)**	(10)
Unrecognized net transition obligation	**2**	2	**—**	—
Net recorded asset (liability) at December 31	**$ 64**	$ (5)	**$(145)**	$(152)

(1) Discount rate decreased from 7.75% to 7.25%, effective March 1, 2000.
(2) Decreasing to ultimate trend of 6.50% in 2004.

The following table provides the amounts recognized on the Consolidated Balance Sheets (under "sundry," "deferred credits and other liabilities," and "postretirement benefits other than pensions") at December 31:

(Dollars in millions)	Pension Benefits		Other Postretirement Benefits	
	2001	2000	**2001**	2000
Prepaid benefit cost	**$146**	$ 75	**$ —**	$ —
Accrued benefit cost	**(82)**	(80)	**(145)**	(152)
Additional minimum liability	**(18)**	(12)	**—**	—
Intangible asset	**3**	4	**—**	—
Accumulated other comprehensive income, pretax	**15**	8	**—**	—
Net recorded asset (liability)	**$ 64**	$ (5)	**$(145)**	$(152)

The following table provides the components of net periodic benefit cost (income) for the plans:

(Dollars in millions) For the years ended December 31,	Pension Benefits			Other Postretirement Benefits		
	2001	2000	1999	**2001**	2000	1999
Service cost	**$ 49**	$ 41	$ 48	**$ 11**	$ 11	$ 15
Interest cost	**141**	153	142	**41**	37	40
Expected return on assets	**(219)**	(239)	(206)	**(39)**	(37)	(32)
Amortization of:						
Transition obligation	**1**	1	1	**10**	11	11
Prior service cost	**6**	6	6	**(1)**	(2)	(1)
Actuarial (gain) loss	**(39)**	(55)	(31)	**(3)**	(8)	2
Special termination benefit	**13**	54	—	**—**	2	—
Curtailment cost (credit)	**1**	(2)	—	**—**	—	—
Settlement credit	**(19)**	(26)	—	**—**	—	—
Regulatory adjustment	**51**	18	17	**30**	26	15
Total net periodic benefit cost (income)	**$ (15)**	$ (49)	$ (23)	**$ 49**	$ 40	$ 50

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percent change in assumed health care cost trend rates would have the following effects:

(Dollars in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health-care benefit cost	$ 9	$ (7)
Effect on the health-care component of the accumulated postretirement benefit obligation	$90	$(71)

Except for one nonqualified, unfunded retirement plan, all pension plans had plan assets in excess of accumulated benefit obligations. For that one plan the projected benefit obligation and accumulated benefit obligation were $79 million and $68 million, respectively, as of December 31, 2001, and $65 million and $51 million, respectively, as of December 31, 2000.

Other postretirement benefits include retiree life insurance, medical benefits for retirees and their spouses, and Medicare Part B reimbursement for certain retirees.

Savings Plans

The company offers savings plans, administered by plan trustees, to all eligible employees. Eligibility to participate in the various employer plans ranges from one month to one year of completed service. Employees may contribute, subject to plan provisions, from one percent to 15 percent of their regular earnings. After one year of completed service, the company begins to make matching contributions. Employer contribution amounts and methodology vary by plan, but generally the contribution is equal to 50 percent of the first 6 percent of eligible base salary contributed by employees. Employer contributions are invested in company stock (new issuances or market purchases) and must remain so invested until termination of employment. At the direction of the employees, the employees' contributions are invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts. Employer contributions for the Sempra Energy and SoCalGas plans are partially funded by the employee stock ownership plan referred to below. Company contributions to the savings plans were $17 million in 2001, $15 million in 2000 and $14 million in 1999. The market value of company stock held by the savings plan was $530 million and $501 million at December 31, 2001 and 2000, respectively.

Employee Stock Ownership Plan

All contributions to the Trust are made by the company; there are no contributions made by the participants.

As the company makes contributions to the ESOP, the ESOP debt service is paid and shares are released in proportion to the total expected debt service. Compensation expense is charged and equity is credited for the market value of the shares released. Income tax deductions are based on the cost of the shares. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.7 million and 2.8 million shares of Sempra Energy common stock, with fair values of $65.9 million and $65.5 million, at December 31, 2001, and 2000, respectively.

NOTE 9. STOCK-BASED COMPENSATION

Sempra Energy has stock-based compensation plans intended to align employee and shareholder objectives related to the long-term growth of the company. The plans permit a wide variety of stock-based awards, including nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments and dividend equivalents.

In 2001, 777,500 shares of restricted company stock were awarded to key employees. In 1999, 85,400 shares of restricted company stock were awarded to officers. The corresponding weighted average fair values of the shares granted were $23.37 and $21.00, respectively. There was no restricted company stock awarded in 2000. Subject to earlier forfeitures upon termination of employment, each award vests at the end of seven years, subject to earlier vesting over a four-year period upon satisfaction of objective performance-based goals. Holders of restricted stock have full voting and dividend rights. Compensation expense for the issuance of restricted stock was approximately $5 million in 2001, $1 million in 2000 and $1 million in 1999.

In 2001, 2000 and 1999, Sempra Energy granted to officers and approximately 200 key employees 2,934,800, 4,339,000 and 3,442,400 stock options, respectively. The option price is equal to the market price of common stock at the date of grant. The grants, which vest over a one to four-year period, include options with and without performance-based dividend equivalents. The stock options expire 10 years from the date of grant, subject to earlier expiration upon termination of employment. Compensation expense (or reduction thereof) for the stock option grants (all associated with the options with the dividend equivalents) and similar awards was $7 million, $14 million, and ($13 million) in 2001, 2000 and 1999, respectively.

As of December 31, 2001, 12,805,700 shares were authorized and available for future grants of restricted stock and/or stock options. In addition, on January 1 of each year, additional shares amounting to 1.5 percent of the outstanding shares of Sempra Energy common stock become available for grant.

The plans permit the granting of dividend equivalents, which provide grantees the opportunity to receive some or all of the cash dividends that would have been paid on the shares since the grant date. All grants thus far have made the dividend equivalents dependant on the attainment of certain performance goals. For grants prior to July 1, 1998, payment of the dividend equivalents is also contingent upon an in-the-money exercise of the related options.

In 1995, SFAS No. 123 “Accounting for Stock-Based Compensation,” was issued. It encourages a fair value-based method of accounting for stock-based compensation. As permitted by SFAS No. 123, the company adopted only its disclosure requirements and continues to account for stock-based compensation in accordance with the provisions of Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees.”

Had compensation cost for the stock-based compensation plans been determined based on the fair value at the grant dates for awards under those plans, consistent with the method of SFAS No. 123, net income would have been reduced by $1 million in 2001 and $16 million in 1999. The company’s net income (earnings per diluted share) would have been $517 million ($2.52), $429 million ($2.06) and $378 million ($1.59) for 2001, 2000 and 1999, respectively.

STOCK OPTION ACTIVITY

	Shares Under Option	Average Exercise Price	Options Exercisable at December 31
OPTIONS WITH DIVIDEND EQUIVALENTS			
December 31, 1998	3,596,660	$22.06	1,387,523
Granted	1,451,100	21.00	
Exercised	(254,886)	17.32	
Cancelled	(99,677)	23.34	
December 31, 1999	4,693,197	21.96	1,844,079
Exercised	(399,875)	18.91	
Cancelled	(264,749)	23.39	
December 31, 2000	4,028,573	22.17	2,462,574
Exercised	(588,315)	20.92	
Cancelled	(119,911)	22.46	
December 31, 2001	3,320,347	$22.38	2,508,328
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
December 31, 1998	2,030,232	$24.28	523,661
Granted	1,991,300	21.00	
Exercised	(12,781)	15.20	
Cancelled	(55,746)	23.25	
December 31, 1999	3,953,005	22.67	1,019,056
Granted	4,339,000	19.03	
Exercised	(329,313)	19.10	
Cancelled	(397,271)	25.07	
December 31, 2000	7,565,421	20.61	1,659,244
Granted	2,934,800	22.50	
Exercised	(421,633)	18.79	
Cancelled	(204,134)	23.59	
December 31, 2001	9,874,454	$21.19	3,143,319

Additional information on options outstanding at December 31, 2001, is as follows:

Range of Exercise Prices	Number of Shares	Average Remaining Life	Average Exercise Price
Outstanding Options			
$12.80-$16.12	233,200	2.96	$15.55
$17.00-$22.65	10,305,913	7.98	$20.46
$24.27-$27.31	2,655,688	6.66	$25.97
	13,194,801	7.62	$21.48
Exercisable Options			
$12.80-$16.12	233,200		$15.55
$17.00-$22.65	3,334,313		$19.82
$24.27-$27.31	2,084,134		$25.86
	5,651,647		$21.87

The grant-date market value of each option grant (including dividend equivalents where applicable) was estimated using the modified Black-Scholes option-pricing model. Weighted average grant-date market values for options granted in 2001, 2000 and 1999 were $4.29, $3.07 and $4.24, respectively.

The assumptions that were used to determine these grant-date market values are as follows:

	2001	2000	1999
Stock price volatility	**24%**	20%	19%
Risk-free rate of return	**4.6%**	6.8%	5.5%
Annual dividend yield*	**4.3%**	5.4%	6.11%
Expected life	**6 Years**	6 Years	6 Years

* The assumed yield for the options that include dividend equivalents is zero.

NOTE 10. FINANCIAL INSTRUMENTS

Fair Value

The fair values of certain of the company's financial instruments (cash, temporary investments, funds held in trust, notes receivable, dividends payable, short-term debt and customer deposits) approximate the carrying amounts. The following table provides the carrying amounts and fair values of the remaining financial instruments at December 31:

	2001		2000	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	**$ 317**	**$ 272**	$ 365	$ 345
First-mortgage bonds	**$1,274**	**$1,297**	$1,364	$1,361
Notes payable	**1,300**	**1,327**	800	814
SDG&E rate — reduction bonds	**395**	**411**	461	462
Debt incurred to acquire limited partnerships	**187**	**147**	233	188
Other long-term debt	**528**	**545**	794	807
Total long-term debt	**$3,684**	**$3,727**	$3,652	$3,632
Preferred stock of subsidiaries	**$ 204**	**$ 162**	$ 204	$ 146
Mandatorily redeemable trust preferred securities	**$ 200**	**$ 214**	$ 200	$ 188

The fair values of investments in limited partnerships accounted for under the cost method were estimated based on the present value of remaining cash flows, discounted at rates available for similar investments. The fair values of debt incurred to acquire limited partnerships, which did not have readily determinable quoted market prices, were estimated based on the present value of the future cash flows, discounted at rates available for similar notes with comparable maturities. The fair values of the other long-term debt, preferred stock and mandatorily redeemable trust preferred securities were estimated based on quoted market prices for them or for similar issues.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, the company adopted SFAS 133, as amended by SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities." As amended, SFAS 133 requires that an entity recognize all derivative instruments as either assets or liabilities in the statement of financial position, measure the instruments at fair value and recognize changes in the fair value of derivatives in earnings in the period of change unless the derivative instrument qualifies as an effective hedge that offsets certain exposures.

At December 31, 2001, $57 million in current assets, $27 million in noncurrent assets, $195 million in current liabilities and $835 million in noncurrent liabilities were recorded in the Consolidated Balance Sheets for fixed-priced contracts and other derivatives. Regulatory assets and liabilities were established to the extent that derivative gains and losses are recoverable or payable through future rates. As such, $193 million in current regulatory assets, $830 million in noncurrent regulatory assets, $50 million in regulatory balancing account liabilities, $4 million in current regulatory liabilities and $1 million in noncurrent regulatory liabilities were recorded in the Consolidated Balance Sheets as of December 31, 2001. The remaining $22 million was a market value adjustment to long-term debt related to two fixed-to-floating interest rate swaps. There was not a material impact to the Statements of Consolidated Income.

Changes in the fair value of derivative instruments have been recognized in the classification shown below (dollars in millions):

	2001	2000	1999
Other operating revenues	$ 1,035	$795	$450
Cost of natural gas distributed	$ 53	$ 72	$ —

Market Risk

The company's policy is to use derivative financial instruments to manage exposure to fluctuations in interest rates, foreign-currency exchange rates and energy prices. The company also uses and trades derivative financial instruments in its energy trading and marketing activities. Transactions involving these financial instruments are with firms believed to be credit-worthy and major exchanges. The use of these instruments exposes the company to market and credit risk which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

Interest-Rate Risk Management

The company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. At December 31, 2001, the company had three such agreements. SDG&E has an interest-rate swap agreement that matures in 2002 and effectively fixes the interest rate on $45 million of variable-rate underlying debt at 5.4 percent. This floating- to-fixed-rate swap does not qualify for hedge accounting and, therefore, the gains and losses associated with the change in fair value are recorded in the Statements of Consolidated Income. For the year ended December 31, 2001, the effect on income was a $1 million loss. Although this financial instrument does not meet the hedge accounting criteria of SFAS 133, it continues to be effective in achieving the risk management objectives for which it was intended.

The remaining two agreements are fixed-to-floating-rate swaps. The company has one such agreement on $500 million of underlying debt which matures in 2004 and effectively causes the interest rate on the debt to vary at the weighted-average rate of LIBOR plus 1.329 percent. SoCalGas has the other agreement, which is a cancelable-call interest-rate swap, exchanging a fixed rate obligation of 6.875 percent on its $175 million first-mortgage bonds, maturing in 2025, for a floating rate of LIBOR plus 4 basis points. The transaction may be canceled every 5 years by either party by payment of the mark-to-market value, or may be canceled by the counterparty at any time the bonds are callable, by payment to SoCalGas of the applicable call premium on the bonds. The company believes both swaps are fully effective in their purpose of converting the fixed rate stated in the debt to a floating rate and the swaps meet the criteria for accounting under the short-cut method defined in SFAS No. 133 for fair value hedges of debt instruments. Accordingly, a market value adjustment of $22 million (as discussed above) was recorded in long-term debt at December 31, 2001 and no net gains or losses were recorded in income related to these swaps.

Energy Derivatives

The company utilizes derivative financial instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative financial instruments are comprised of futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received and, in the case of the California utilities, the prices to be charged to their customers. See Note 2 of the notes to Consolidated Financial Statements for discussion of how these derivatives are classified under SFAS 133.

Energy Contracts

The California utilities record gas and electric energy contracts in “Cost of gas distributed” and “Electric fuel and net purchased power,” respectively, in the Statements of Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The company’s trading operations include the net effects of its contracts in trading revenues. The majority of the California utilities’ contracts result in physical delivery, which is less frequent at the trading operations.

Sempra Energy Trading and Sempra Energy Solutions

SET derives a substantial portion of its revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum, petroleum products and other commodities, for which it quotes bid and asked prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. In addition, it takes positions in energy markets based on the expectation of future market conditions. These positions include options, forwards, futures and swaps. These financial instruments represent contracts with counterparties whereby payments are linked to or derived from energy market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. For the year ended December 31, 2001, substantially all of SET's derivative transactions were held for trading and marketing purposes. Sempra Energy guarantees many of SET's transactions.

SES derives a portion of its revenue from delivering electric and gas supplies to its commercial and industrial customers. Such contracts are hedged to preserve margin and carry minimal market risk. Exchange-traded and over-the-counter instruments are used to hedge contracts. The derivatives and financial instruments used to hedge the transactions include swaps, forwards, futures, options or combinations thereof.

Both SET and SES mark these derivatives to market daily, with gains and losses recognized in earnings. These instruments are included in the Consolidated Balance Sheets as energy trading assets or liabilities. Certain instruments, such as swaps, are entered into and closed out within the same period. SET records net gains and losses on these derivative transactions in other operating revenues in the Statements of Consolidated Income. For SES, unrealized gains or losses are also included in other operating revenues. As transactions are settled, SES records the realized retail contracts as revenues while wholesale contracts and related financial instruments are recognized as other operating expenses.

At SET, market risk arises from the potential for changes in the value of financial instruments resulting from fluctuations in natural gas, electricity, petroleum, petroleum products and other commodities exchange prices and basis. Market risk is also affected by changes in volatility and liquidity in markets in which these instruments are traded. Market risk for SES from fluctuations in natural gas or electricity prices is minimized by SES' hedging strategy as described above.

SET also carries an inventory of financial instruments. Market making and proprietary positions are managed in concert in order to maximize trading profits due to the close relationship between commodities and the related financial instruments.

SET's credit risk from financial instruments as of December 31, 2001, is represented by the positive fair value of financial instruments after consideration of collateral. Credit risk, however, relates to the net losses that would be recognized if all counterparties failed completely to perform their obligations. Options written do not expose SET to credit risk. Exchange traded futures and options are not deemed to have significant credit exposure as the exchanges guarantee that every contract will be properly settled on a daily basis. For SES, credit risk is associated with its retail customers.

The following table summarizes the counterparty credit quality and exposure for SET and SES at December 31, 2001 expressed in terms of net replacement value (dollars in millions). These exposures are net of collateral in form of customer margin and/or letters of credit of $175 million:

Counterparty credit quality:	Total
SET:	
Commodity Exchanges	$ 133
AAA	53
AA	105
A	577
BBB	476
Below investment grade	335
Total	$1,679
SES:	
AA	$ 4
A	18
BBB	7
Below investment grade and not rated	190
	$ 218

Financial instruments with maturities or repricing characteristics of 180 days or less, including cash and cash equivalents, are considered short-term and, therefore, the carrying values of these financial instruments approximate their fair values. SET's commodities owned, energy trading assets and energy trading liabilities are carried at fair value. Accordingly, SET has determined that all of its financial instruments are recorded at fair value. SES has determined that the carrying amount of its retail energy and wholesale energy contracts and financial instruments approximates fair value.

Energy trading assets and liabilities are recorded on a trade-date basis and adjusted daily to current value, and include amounts due from commodity clearing organizations, amounts due to/from trading counterparties, unrealized gains and losses from exchange traded futures and options, and OTC swaps, forwards and options. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon liquidation of these contracts under current market conditions. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists.

Based on quarterly measurements, the average fair values during 2001 for energy trading assets and liabilities approximate $3.0 billion and $2.2 billion, respectively.

The carrying value of energy trading assets and energy trading liabilities approximate the following:

December 31 (Dollars in millions)	**2001**	2000
ENERGY TRADING ASSETS		
Unrealized gains on swaps and forwards	**$1,674**	$2,647
OTC commodity options purchased	**425**	684
Due from trading counterparties	**343**	653
Due from commodity clearing organizations and clearing brokers	**133**	99
Total	**$2,575**	$4,083
ENERGY TRADING LIABILITIES		
Unrealized losses on swaps and forwards	**$1,340**	$2,590
OTC commodity options written	**290**	612
Due to trading counterparties	**163**	417
Total	**$1,793**	$3,619

Futures and exchange traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at fair value based on closing exchange quotations. Commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from dealer quotations and underlying commodity exchange quotations. OTC options purchased and written are recorded on a trade-date basis. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates, as applicable. For long dated forward transactions, where there are no dealer or exchange quotations, fair values are derived using internally developed valuation methodologies based on available market information. Where market rates are not quoted or where management deems appropriate, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ from realized values. Changes in the fair value are recorded currently in income.

Notional amounts do not necessarily represent the amounts exchanged by parties to the financial instruments and do not measure SET's or SES's exposure to credit or market risks. The notional or contractual amounts are used to summarize the volume of financial instruments, but do not reflect the extent to which positions may offset one another. Accordingly, both companies are exposed to much smaller amounts.

The notional amounts of SET's and SES's financial instruments at December 31 were:

(Dollars in millions)	**2001**	2000
Forwards and commodity swaps	**$33,597**	$45,656
Options purchased	**21,542**	13,496
Options written	**18,253**	13,799
Futures and exchange options	**4,721**	3,117
Total	**$78,113**	$76,068

NOTE 11. PREFERRED STOCK OF SUBSIDIARIES

December 31 (Dollars in millions except call price)	Call Price	2001	2000
Pacific Enterprises (not subject to mandatory redemption):			
Without par value, authorized 15,000,000 shares:			
$4.75 Dividend, 200,000 shares outstanding	$100.00	**$ 20**	$ 20
$4.50 Dividend, 300,000 shares outstanding	$100.00	**30**	30
$4.40 Dividend, 100,000 shares outstanding	$101.50	**10**	10
$4.36 Dividend, 200,000 shares outstanding	$101.00	**20**	20
$4.75 Dividend, 253 shares outstanding	$101.00	**—**	—
Total		**80**	80
SoCalGas (not subject to mandatory redemption):			
$25 par value, authorized 1,000,000 shares:			
6% Series, 28,049 shares outstanding		**1**	1
6% Series A, 783,032 shares outstanding		**19**	19
Without par value, authorized 10,000,000 shares		**—**	—
Total		**20**	20
SDG&E:			
Not subject to mandatory redemption:			
$20 par value, authorized 1,375,000 shares:			
5% Series, 375,000 shares outstanding	$ 24.00	**8**	8
4.50% Series, 300,000 shares outstanding	$ 21.20	**6**	6
4.40% Series, 325,000 shares outstanding	$ 21.00	**7**	7
4.60% Series, 373,770 shares outstanding	$ 20.25	**7**	7
Without par value:			
$1.70 Series, 1,400,000 shares outstanding	$ 25.85	**35**	35
$1.82 Series, 640,000 shares outstanding	$ 26.00	**16**	16
Total not subject to mandatory redemption		**79**	79
Subject to mandatory redemption:			
Without par value: $1.7625 Series, 1,000,000 shares outstanding	$ 25.00	**25**	25
Total		**$204**	$204

PE preferred stock is callable at the applicable redemption price for each series, plus any unpaid dividends. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $100 per share plus any unpaid dividends.

None of SoCalGas' preferred stock is callable. All series have one vote per share and cumulative preferences as to dividends, and have a liquidation value of $25 per share, plus any unpaid dividends. In addition, the 6% Series preferred stock would also share pro rata with common stock in the remaining assets.

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share, plus any unpaid dividends. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are currently callable except for the $1.70 and $1.7625 Series (callable in 2003). The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares per year from 2003 to 2007; the remaining 750,000 shares must be redeemed in 2008.

Mandatorily Redeemable Trust Preferred Securities

On February 23, 2000, a wholly owned subsidiary trust of the company issued 8,000,000 shares of preferred stock in the form of 8.90-percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). The QUIPS have cumulative preferences as to distributions, are nonvoting and have a par and liquidation value of $25 per share. Cash dividends are paid quarterly and the QUIPS mature on February 23, 2030, subject to extension to a date not later than February 23, 2049, and shortening to a date not earlier than February 23, 2015. The QUIPS are subject to mandatory redemption and the company has guaranteed payments to the extent that the trust does not have funds available to make distributions. The trust has no assets except its corresponding receivable from Sempra Energy. The QUIPS are callable on or after February 23, 2005 and there are no sinking fund provisions. The QUIPS are reflected as “Mandatorily redeemable trust preferred securities” on the company’s Consolidated Balance Sheets and cash dividend payments are shown as “Trust preferred distributions by subsidiary” on the company’s Statements of Consolidated Income. Proceeds of this issuance, together with $500 million of long-term 7.95% notes due 2010 (see Note 5), were used to finance substantially all of the tender offer referred to in Note 12.

NOTE 12. SHAREHOLDERS’ EQUITY AND EARNINGS PER SHARE

The only difference between basic and diluted earnings per share is the effect of common stock options. For 2001, 2000 and 1999, the effect of dilutive options was equivalent to an additional 1,745,000, 190,000 and 308,000 shares, respectively, using the treasury stock method, whereby the proceeds from the exercise price are assumed to be used to repurchase shares on the open market at the average market price for the year. This excludes options covering 2.1 million shares, 6.6 million shares and 3.3 million shares for 2001, 2000 and 1999, respectively, for which the exercise price was greater than the average market price for common stock during the respective periods.

The company is authorized to issue 750,000,000 shares of no-par-value common stock and 50,000,000 shares of Preferred Stock. Excluding shares held by the ESOP, common stock activity consisted of the following:

	2001	2000	1999
Common shares outstanding, January 1	**201,927,524**	237,408,051	236,956,683
Stock options exercised	**1,009,948**	729,188	267,667
Long-term incentive plan	**777,500**	—	85,400
Common stock investment plan*	**761,154**	—	—
Shares released from ESOP	**134,645**	125,848	126,721
Shares repurchased	**(60,000)**	(36,304,740)	—
Shares forfeited and other	**(75,409)**	(30,823)	(28,420)
Common shares outstanding, December 31	**204,475,362**	201,927,524	237,408,051

* In 2001 participants in the Direct Stock Purchase Plan reinvested dividends and purchased newly issued shares. In 1999 and 2000 open-market shares were used.

The payment of future dividends and the amount thereof are within the discretion of the company’s board of directors. The CPUC’s regulation of the California utilities’ capital structure limits to $458 million the portion of the California utilities’ December 31, 2001, retained earnings that is available for dividends to the company.

Tender Offer

On February 25, 2000, the company completed a self-tender offer, purchasing 36.1 million shares of its outstanding common stock at $20 per share. In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase additional shares of common stock from time to time in the open market or in privately negotiated transactions. The company acquired 60,000 shares and 162,400 shares under this authorization in 2001 and 2000, respectively.

NOTE 13. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California utilities buy natural gas under short-term and long-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. SoCalGas and SDG&E transport gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates.

SoCalGas has commitments for firm pipeline capacity under contracts with pipeline companies that expire at various dates through 2006.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines which expire on various dates between 2003 and 2023. SDG&E has a long-term purchase agreement with a Canadian supplier that expires in August 2003, and in which the delivered cost is tied to the California border spot-market price. SDG&E purchases natural gas on a spot basis to fill its additional long-term pipeline capacity. SDG&E intends to continue using the long-term pipeline capacity in other ways as well, including the transport of other natural gas for its own use and the release of a portion of this capacity to third parties.

At December 31, 2001, the future minimum payments under natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas
2002	$181	$468
2003	183	174
2004	188	—
2005	184	—
2006	105	—
Thereafter	155	—
Total minimum payments	$996	$642

Total payments under natural gas contracts were $2.6 billion in 2001, $1.6 billion in 2000, and $1.3 billion in 1999.

Purchased-Power Contracts

SDG&E buys electric power under several long-term contracts. The contracts expire on various dates between 2003 and 2025. Prior to the electric rate ceiling described in Note 14, the above-market cost of contracts was recovered from SDG&E's customers. In general, the market value of these contracts was recovered by bidding them into the California Power Exchange (PX) and receiving revenue from the PX for bids accepted. As of January 1, 2001, in compliance with a FERC order prohibiting sales to the PX, SDG&E no longer bids those contracts into the PX. Those contracts are now used to serve customers in compliance with a CPUC order. In late 2000, SDG&E entered into additional contracts to serve customers instead of buying all of its power from the PX. These contracts expire in 2003.

At December 31, 2001, the estimated future minimum payments under the long-term contracts were:

(Dollars in millions)	
2002	$ 224
2003	218
2004	172
2005	173
2006	170
Thereafter	2,000
Total minimum payments	$2,957

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Total payments under the contracts were $512 million in 2001, $257 million in 2000 and $251 million in 1999.

On January 17, 2001, the California Assembly passed a bill (AB1) to allow the DWR to purchase power under long-term contracts for the benefit of California consumers. In accordance with AB1, SDG&E entered into an agreement with DWR under which DWR purchases SDG&E's full net short position (the power needed by SDG&E's customers, other than that provided by SDG&E's nuclear generating facilities or its previously existing purchase power contracts) through December 31, 2002. The CPUC is conducting proceedings intended to establish guidelines and procedures for the eventual resumption of electricity procurement by SDG&E and the other California IOUs. For additional discussion of this matter see Note 14.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2002 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 7 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases on real property. Property, plant and equipment includes $35 million at December 31, 2001, and $92 million at December 31, 2000, related to these leases. The associated accumulated amortization is $18 million and $55 million, respectively. The decreases in 2001 resulted from SDG&E's terminating its capital lease agreement for nuclear fuel in mid-2001. SDG&E now owns its nuclear fuel.

At December 31, 2001, the minimum rental commitments payable in future years under all noncancellable leases were:

(Dollars in millions)	Operating Leases	Capitalized Leases
2002	$ 66	$ 7
2003	74	3
2004	98	3
2005	94	2
2006	92	1
Thereafter	1,183	1
Total future rental commitment	$1,607	17
Imputed interest (9% to 15%)		(3)
Net commitment		$14

In connection with the quasi-reorganization described in Note 2, PE recorded liabilities of $102 million to adjust to fair value the operating leases related to its headquarters and other facilities at December 31, 1992. The remaining amount of these liabilities was $49 million at December 31, 2001. These leases are included in the above table.

Rent expense totaled $92 million in 2001, $102 million in 2000 and $108 million in 1999.

Other Commitments and Contingencies

In October 2001, SEI and CMS Energy Corporation announced plans to jointly develop a liquefied natural gas (LNG) receiving facility on a 300-acre site along Baja California's Pacific coast near Ensenada, Mexico. The joint venture will develop the $400 million facility and related port infrastructure, which is expected to provide one billion cubic feet per day of natural gas. SEI has entered into a memorandum of understanding with a Bolivian consortium for the potential supply of LNG to the facility. Commercial operation of the facility is scheduled to begin in late 2005. As of December 31, 2001, no contractual commitments existed yet.

In February 2001, the company announced plans to construct Termoelectrica de Mexicali, a $350 million, 600-megawatt power plant near Mexicali, Mexico. Fuel for the plant will be supplied via the planned pipeline from Arizona to Tijuana referred to below. It is anticipated that the electricity produced by the plant will be exported for consumption in the United States via the 230,000-volt transmission line which is also under construction. Construction of the power plant began in the second half of 2001. $135 million has been invested in the project, which is scheduled for completion by mid-2003. As of December 31, 2001, SER has additional commitments of $135 million related to the purchase of steam and gas turbine generators and engineering and procurement services.

In December 2000, SER obtained approvals from the appropriate state agencies to construct the Elk Hills Power Project, a $410 million 570-megawatt power plant near Bakersfield, California. Elk Hills is being developed in a 50/50 joint venture with Occidental Energy Ventures Corporation and will supply electricity to California. As of December 31, 2001, SER has invested $133 million in the project and has commitments of approximately $70 million. The project is anticipated to be completed during the first half of 2003. Information concerning litigation with Occidental is provided below.

In December 2000, SER obtained approval from the appropriate state agencies to construct the Mesquite Power Plant (Mesquite Power). Located near Phoenix, Arizona, Mesquite Power is a $700 million, 1,200-megawatt project which will provide electricity to wholesale energy markets in the Southwest. Construction began in March 2001, and completion is anticipated by 2003. Expenditures as of December 31, 2001 are $259 million and SER has commitments of $337 million related to this project. Expenditures have been financed through a synthetic lease agreement. However, additional financing under the synthetic lease would require obtaining additional bank commitments or the posting of U.S. Treasury obligations in similar amounts.

SER, as construction agent for the lessor, is responsible for completing construction in a timely manner. Upon completion of the project, SER is required to make lease payments to the lessor in an amount sufficient to provide a specified return to the investors. In 2005, SER has the option to extend the lease at fair market value, purchase the project at a fixed amount, or act as remarketing agent for the lessor to sell the project. If SER elects the remarketing option, it may be required to pay the lessor up to 85 percent of the project cost if the proceeds from remarketing are insufficient to repay the lessor's investors. The lease is guaranteed by Sempra Energy and the availability of additional financing is conditioned upon Sempra Energy's continuing to have credit ratings of at least BBB- by S&P or Baa3 by Moody's. The lease also requires Sempra Energy to maintain a debt-to-total capitalization ratio, (as defined in the lease), of not to exceed 65%. As a synthetic lease, neither the asset nor the liability is included on the Consolidated Balance Sheets. If they were, assets and long-term debt would have been increased by $225 million at December 31, 2001, reflecting costs incurred on the project, all in 2001.

As of December 31, 2001, SER has invested $100 million for gas turbines and other power plant projects. SER has additional commitments related to these projects of $125 million.

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 megawatts of power to the state. SER intends to deliver most of this electricity from its projected portfolio of plants in the western United States and Baja California, Mexico. Sales under the contract comprise more than two-thirds of the projected capacity of these facilities and the profits therefrom are significant to the company's ability to increase its earnings. Subsequent to the state's signing of this contract and electricity-supply contracts with other vendors, various state officials have contended that the rates called for by the contracts are too high. These rates substantially exceed current spot-market prices for electricity, but are substantially lower than those prevailing at the time the contracts were signed. In February 2002, the CPUC and the California Electricity Oversight Board petitioned the Federal Energy Regulatory Commission to determine that the contracts do not provide just and reasonable rates, and to abrogate or reform the contracts. The company believes that the contract prices were fair, but has offered to renegotiate certain aspects of the contract (which would not affect the long-term profitability) in a manner mutually beneficial to SER and the state.

In June 2000, SEI and PG&E Corporation announced a joint agreement to construct the North Baja Pipeline, a $230 million, 215-mile natural gas pipeline which will extend from Arizona to the Rosarito Pipeline south of Tijuana and supply natural gas to new and existing power plants and to industrial customers in northern Baja California, including SER's Termoelectrica de Mexicali plant discussed above. SEI will construct, own and operate the Mexican portion of the pipeline ($130 million and 135 miles) and has invested approximately $75 million through 2001. PG&E's National Energy Group is responsible for the U.S. segment of the operations and is entitled to the operating income or losses stemming therefrom. As of December 31, 2001, SEI has commitments of $25 million related to this project. Completion of SEI's portion of the project is contemplated for the summer of 2002.

In December 1999, Sempra Atlantic Gas (SAG), a subsidiary of SEI, was awarded a 25-year franchise by the provincial government of Nova Scotia to build and operate a natural gas distribution system in Nova Scotia. In September 2001, due to new conditions required by the government of Nova Scotia, SAG notified the government that it intended to surrender its natural gas distribution franchise. SAG had invested $30 million through September 2001 and has expensed the costs believed to be nonrecoverable.

Environmental Issues

The company's operations are subject to federal, state and local environmental laws and regulations governing hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. Most of the environmental issues faced by the company occur at the California utilities. However, as SER constructs new power plants, additional environmental issues will arise requiring the company's attention. As applicable, appropriate and relevant, these laws and regulations require that the company investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations, including sites at which the company has been identified as a Potentially Responsible Party under the federal Superfund laws and comparable state laws. Costs incurred to operate the facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Costs that mitigate or prevent future environmental contamination or extend the life, increase the capacity or improve the safety or efficiency of property utilized in current operations are capitalized. The company's capital expenditures to comply with environmental laws and regulations were $6 million in 2001, $4 million in 2000 and $2 million in 1999. The increase in 2001 is due to purchases of endangered species habitat land to mitigate the impact of the construction of a new transmission line and the installation of air quality control equipment at a compressor station and at various storage fields. The increase in 2000 was due to the installation of air quality control equipment on another compressor facility. The cost of compliance with these regulations over the next five years is not expected to be significant.

Costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the assurance that these costs will be recovered in rates. In 1994, the CPUC approved the Hazardous Waste Collaborative Memorandum account, allowing California's energy utilities to recover their hazardous waste cleanup costs, including those related to Superfund sites or similar sites requiring cleanup. Cleanup costs at electric generation related sites were specifically excluded from the collaborative by the CPUC. Recovery of 90 percent of hazardous waste cleanup costs and related third-party litigation costs and 70 percent of the related insurance-litigation expenses is permitted. In addition, the company has the opportunity to retain a percentage of any insurance recoveries to offset the 10 percent of costs not recovered in rates.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of the California utilities' manufactured-gas sites (21 completed as of December 31, 2001, and 24 to be completed), cleanup at SDG&E's former fossil fuel power plants (all sold in 1999 and actual or estimated cleanup costs included in the transactions), cleanup of third-party waste-disposal sites used by the company, which has been identified as a Potentially Responsible Party (investigations and remediations are continuing), and mitigation of damage to the marine environment caused by the cooling-water discharge from the San Onofre Nuclear Generating Station (the requirements for enhanced fish protection, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands are in process).

Environmental liabilities are recorded when the company's liability is probable and the costs are reasonably estimable. In many cases, however, investigations are not yet at a stage where the company has been able to determine whether it is liable or, if liability is probable, to reasonably estimate the amount or range of amounts of the cost or certain components thereof. Estimates of the company's liability are further subject to other uncertainties, such as the nature and extent of site contamination, evolving remediation standards and imprecise engineering evaluations. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as necessary. At December 31, 2001, the company's accrued liability for environmental matters was $65 million, of which approximately $52 million related to manufactured-gas sites, $10 million related to cleanup at SDG&E's former fossil-fueled power plants and $3 million related to waste-disposal sites used by the company (which has been identified as a Potentially Responsible Party). The accruals for the manufactured-gas and waste-disposal sites are expected to be paid ratably over the next five years. The accruals for SDG&E's former fossil-fueled power plants are expected to be paid ratably over the next two years. There are no circumstances currently known to management that would require adjustment to the accruals.

Nuclear Insurance

SDG&E and the co-owners of SONGS have purchased primary insurance of $200 million, the maximum amount available, for public-liability claims. An additional $9.3 billion of coverage is provided by secondary financial protection required by the Nuclear Regulatory Commission and provides for loss sharing among utilities owning nuclear reactors if a costly accident occurs. SDG&E could be assessed retrospective premium adjustments of up to $36 million in the event of a nuclear incident involving any of the licensed, commercial reactors in the United States, if the amount of the loss exceeds $200 million. In the event the public-liability limit stated above is insufficient, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims, which could include an additional assessment on all licensed reactor operators.

Insurance coverage is provided for up to $2.8 billion of property damage and decontamination liability. Coverage is also provided for the cost of replacement power, which includes indemnity payments for up to three years, after a waiting period of 12 weeks. Coverage is provided primarily through mutual insurance companies owned by utilities with nuclear facilities. If losses at any of the nuclear facilities covered by the risk-sharing arrangements were to exceed the accumulated funds available from these insurance programs, SDG&E could be assessed retrospective premium adjustments of up to $7 million.

Both the public-liability and property insurance (including replacement power coverage) include coverage for losses resulting from acts of terrorism. This includes the risk-sharing arrangement with other nuclear facilities.

Department Of Energy Decommissioning

The Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the Department of Energy (DOE) nuclear fuel enrichment facilities. Utilities which have used DOE enrichment services are being assessed a total of $2.3 billion, subject to adjustment for inflation, over a 15-year period ending in 2006. Each utility's share is based on its share of enrichment services purchased from the DOE through 1992. SDG&E's annual assessment is approximately $1 million. This assessment is recovered through SONGS revenue.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. Continued delays by the DOE can lead to increased cost of disposal, which could be significant. If this occurs and the company is unable to recover the increased costs from the federal government or from its customers, the company's profitability from SONGS would be adversely affected.

Litigation

Lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek class-action certification and allege that Sempra Energy, SoCalGas, SDG&E and El Paso Energy Corp. acted to drive up the price of natural gas for Californians by agreeing to stop a pipeline project that would have brought new and less-expensive natural gas supplies into California. Management believes the allegations are without merit.

Various 2000 lawsuits, which seek class-action certification and which have been consolidated in San Diego Superior Court, allege that company subsidiaries unlawfully manipulated the electric-energy market. Management believes the allegations are without merit.

SET is a defendant in the action brought by the FERC concerning rates charged certain utilities by sellers of electricity (see FERC Actions in Note 14).

SER is a defendant in an action brought by its joint venture partner, Occidental Energy Ventures (Occidental), concerning the Elk Hills power project that the companies are developing. The lawsuit alleges breach of contract and Occidental claims that SER misrepresented that the entire output of the power plant would be committed to providing power under the contract between SER and the DWR. Management believes the allegations are without merit.

Except for the matters referred to above, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses. Management believes that these matters will not have a material adverse effect on the company's financial condition or results of operations.

SET had been involved in a contractual dispute with Pacific Gas and Electric (PG&E) relating to SET's obligations to deliver certain quantities of natural gas to PG&E. A settlement of this matter has been concluded and approved by the Bankruptcy Court. The settlement will not result in any additional charge to earnings.

Electric Distribution System Conversion

Under a CPUC-mandated program and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2001, the aggregate unexpended amount of this commitment was approximately $110 million. Capital expenditures for underground conversions were $12 million in 2001, $26 million in 2000 and $20 million in 1999.

Concentration Of Credit Risk

The company maintains credit policies and systems to manage overall credit risk. These policies include an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. The California utilities grant credit to utility customers, substantially all of whom are located in their service territories, which together cover most of Southern California and a portion of central California.

Supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity costs beginning in mid-2000 and continuing into 2001. This caused SDG&E's monthly customer bills to be substantially higher than normal. In response, legislation imposed a ceiling of 6.5 cents/kWh on the cost of electricity that SDG&E could pass on to its residential, small-commercial and lighting customers on a current basis. The ceiling extends through December 31, 2002 (December 31, 2003 if deemed by the CPUC to be in the public interest). Once SDG&E is able to pass on these costs, it may experience an increase in customer credit risk. Additional information on this issue is discussed in Note 14.

SET monitors and controls its credit-risk exposures through various systems which evaluate its credit risk, and through credit approvals and limits. To manage the level of credit risk, SET deals with a majority of counterparties with good credit standing, enters into master netting arrangements whenever possible and, where appropriate, obtains collateral. Master netting agreements incorporate rights of setoff that provide for the net settlement of subject contracts with the same counterparty in the event of default.

NOTE 14. ELECTRIC INDUSTRY RESTRUCTURING

Background

In 1996, California enacted legislation (AB 1890) restructuring California's investor-owned electric utility industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates.

As part of the framework for a competitive electric-generation market, the legislation established the PX, which served as a wholesale power pool to which the California IOUs were required to sell all of their power supply (including owned generation and purchased-power contracts) and, except to the extent otherwise authorized by the CPUC, from which they were required to buy all of the electricity needed to serve their retail consumers. The PX also purchased power from nonutility generators through an auction process intended to establish competitive market prices for the power that it sells to the IOUs. An Independent System Operator (ISO) scheduled power transactions and access to the transmission system. In connection with the deregulation of California's electric-utility industry, during 1999 and 2000, the company sold and purchased electricity to and from the PX. Net purchase power reflects sales and purchases to and from the PX/ISO commencing April 1, 1998, at market prices of energy from SDG&E's power plants and from long-term purchase-power contracts. Due to subsequent industry restructuring developments (described below), the PX suspended its trading operations on January 31, 2001.

The restructuring legislation also established a rate freeze on amounts that the IOUs could charge their customers. The rate freeze was designed to generate revenue levels assumed to be sufficient to provide the IOUs with a reasonable opportunity to recover, by December 31, 2001, their costs of generation and purchased power that are fixed and unavoidable and included in customer rates. The rate freeze was to end as to each IOU when it completed recovery of the costs, but in no event later than March 31, 2002.

In June 1999, SDG&E completed the recovery of its stranded costs, other than the future above-market portion of its purchased-power contracts that were in effect at December 31, 1995, and SONGS costs, both of which continue to be collected in rates. Recovery of the other costs was effected by, among other things, the sale of SDG&E's fossil power plants and combustion turbines during the quarter ended June 30, 1999. Therefore, SDG&E is no longer subject to the rate freeze imposed by AB 1890.

With the rate freeze no longer applicable, SDG&E lowered its base rates (the portion of its rates not attributable to electric-commodity costs) and began to pass through to its customers, without markup, the cost of electricity purchased from the PX. SDG&E's overall rates were lower than during the rate freeze, but they also became subject to fluctuation with the actual cost of electricity purchases.

Effect on Customer Rates

As noted above, supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity prices beginning in mid-2000 and continuing into 2001. This caused SDG&E's monthly customer bills to be substantially higher than normal.

These higher prices were initially passed through to SDG&E's customers and resulted in customer bills that in most cases were double or triple those from 1999 and early 2000. This resulted in several legislative and regulatory responses.

California Assembly Bill 265 (AB 265), enacted in September 2000, imposed a ceiling of 6.5 cents kWh on the cost of the electric commodity that SDG&E could pass on to its small-usage customers on a current basis. Customers covered under the commodity rate ceiling generally include residential, small-commercial and lighting customers. The ceiling, retroactive to June 1, 2000, extends through December 31, 2002, and may be extended through December 31, 2003, if the CPUC determines that it is in the public interest to do so. The 6.5-cent rate ceiling is a "floating cap" that can float downward as prices decrease, but cannot exceed actual commodity costs without the approval of the CPUC. The CPUC subsequently approved an increase to the system average rate paid by SDG&E customers (to 7.96 cents per kWh) in order to pass through, without markup, the rates to repay the DWR for its purchases of power, as described below. The agreement for the ending of the earlier rate freeze provided for future recovery of SDG&E's electricity costs that could not be passed on to customers on a current basis. Although it delayed such recovery, AB 265 reaffirmed SDG&E's right to later collect undercollections resulting from the reasonable and prudent costs of procuring the commodity. The reasonableness reviews related to the commodity costs have been settled, as discussed below.

SDG&E accumulates the amount that it pays for electricity in excess of the ceiling rate (the undercollected costs) in an interest-bearing balancing account. SDG&E expects to amortize these amounts, together with interest, in rates charged to customers following the end of the rate-ceiling period. Due to their long-term nature, these undercollected costs are classified as a noncurrent regulatory asset on the company's Consolidated Balance Sheets. The undercollection was $447 million (of which $352 million was included in regulatory assets and $95 million was included in regulatory balancing accounts on the Consolidated Balance Sheets) at December 31, 2000. It increased to approximately $750 million in the first quarter of 2001 and decreased to $392 million at December 31, 2001. The decrease was due primarily to the $100 million refund related to prudence of purchase-power costs and the application of overcollections in other balancing accounts.

Role of the Department of Water Resources

In February 2001, through the passage of AB 1, the DWR began to purchase power from generators and marketers, who had previously sold their power to the PX/ISO, and has entered into long-term contracts for the purchase of a portion of the power requirements of the state's population that is served by IOUs. SDG&E and the DWR have entered into an agreement under which the DWR will continue to purchase power for SDG&E's customers through December 31, 2002.

As the DWR is now purchasing SDG&E's full net short position (the power needed by SDG&E's customers, other than that provided by SDG&E's nuclear generating facilities or its previously existing purchase power contracts) significant growth in these undercollections has ceased.

In April 2001, California law AB 43X took effect, extending the temporary 6.5-cent rate cap to include SDG&E's large customers (the only customer class not previously covered by the rate cap) retroactive to February 7, 2001. The reduced future bills did not add to the undercollection nor did the fourth quarter refunds of past charges above 6.5 cents, since, in large part, the purchases for these customers are covered by the agreement between SDG&E and the DWR.

Memorandum of Understanding

On June 18, 2001 representatives of California Governor Davis, the DWR, Sempra Energy and SDG&E entered into a Memorandum of Understanding (MOU) contemplating the implementation of a series of transactions and regulatory settlements and actions to resolve many of the issues affecting SDG&E and its customers arising out of the California energy crisis. The MOU contemplated the elimination from SDG&E's rate-ceiling balancing account of the undercollected costs that otherwise would be recovered in future customer rates; settlement of reasonableness reviews, electricity purchase contract issues and other regulatory matters.

On August 2, 2001, the CPUC approved a reduction of the rate-ceiling balancing account, as contemplated by the MOU, by the application thereto of overcollections in certain other balancing accounts totaling $70 million.

On October 10, 2001, the CPUC issued a decision approving the delay until 2004 of the effects of revised revenue requirements for the California utilities. However, the decision also denied the California utilities' request to continue equal sharing between ratepayers and shareholders of estimated savings stemming from the 1998 merger between PE and Enova. Instead, the CPUC ordered that all of the estimated 2003 merger savings go to ratepayers. The portion to be refunded to electric ratepayers would be credited to the Transition Cost Balancing Account (TCBA), based on the net present value (NPV) in 2001 of the savings for 2003. Merger savings related to 2001 and 2002 also would be so credited. The combined NPV is estimated to be $39 million. Merger savings allocable to gas ratepayers would be refunded through once-a-year bill credit, as has been the case.

On November 8, 2001, the CPUC approved a $100 million reduction of the rate-ceiling balancing account, in settlement of the reasonableness of SDG&E's electric procurement practices between July 1, 1999 through February 7, 2001.

In January 2002, the CPUC rejected the part of the MOU dealing with a settlement on electricity purchase contracts held by SDG&E. The MOU would have granted SDG&E ownership of its power sale profits in exchange for crediting $219 million to customers to offset the rate-ceiling balancing account. Instead, the CPUC asserted that all the profits associated with the energy purchase contracts should accrue to the benefit of customers. The CPUC estimated these profits as $363 million. The company believes the CPUC's calculation is incorrect and the CPUC has not explained to the company how it arrived at that amount. In addition, the company believes the CPUC's position is incorrect and has challenged the CPUC's original disallowance in the Court of Appeals. The court challenge was put on hold when the MOU was reached. SDG&E has now reactivated the case and has also filed a similar suit in federal court.

Recent Rate Changes

In order to provide sufficient revenues to repay the DWR for the $10 billion of power purchases it made on behalf of the state's three IOUs during the energy crisis, the CPUC issued a decision in September 2001 that established interim rate increases for SDG&E's electric customers in an average amount of approximately 1.46 cents per kWh, resulting in a system average rate of 7.96 cents per kWh when added to the 6.5 cents per kWh rate ceiling discussed above.

On February 21, 2002, the CPUC issued a final decision about the DWR revenue requirement, approving allocation of the DWR's cost of providing power based on actual cost of service, which was lower for SDG&E customers than for those in Northern California and, therefore, avoids a rate hike for SDG&E customers. Based on this allocation, the price SDG&E pays to the DWR drops from the previously proposed rate of 9.02 cents per kWh to 7.29 cents per kWh. SDG&E's system average rate of 7.96 cents per kWh (described above) remains unchanged and will be addressed separately. The CPUC also voted to relinquish oversight over DWR power purchases, which allows the state to proceed with the bond sale of up to $11.1 billion to repay the state's general fund (used for DWR power purchases during the energy crisis) and to cover continuing power purchases. Interested parties have 30 days to appeal the decision.

Direct Access

In September 2001, the CPUC suspended the ability of retail electricity customers to choose their power provider ("direct access") until at least the end of 2003 in order to improve the probability that enough revenue would be available to the DWR to cover the state's power purchases. The decision forbids new direct access contracts after September 20, 2001. In January 2002, a draft decision was issued modifying the direct access suspension decision, suspending direct access retroactively to July 1, 2001. This issue is on the CPUC's agenda for March 21, 2002. An unfavorable decision could adversely affect SES's contracts signed between July 1, 2001 and September 20, 2001. Any such effect is not expected to be material to the company's financial position or liquidity.

FERC Actions

The FERC has been investigating prices charged to the California IOUs by various electric suppliers. The FERC appears to be proceeding in the direction of awarding to the California IOUs a partial refund of the amounts charged. Any such refunds would reduce SDG&E's rate-ceiling balancing account and could result in a payment by SET. Such payment, if any, is not expected to be material to the company's financial position or liquidity. A FERC decision is not expected before the second half of 2002.

More recently, FERC has launched an investigation as to whether there was manipulation of short-term energy prices in the West that resulted in unjust and unreasonable long-term power sales contracts. The results of this investigation will be used by FERC to determine how it should proceed on existing and future complaints about long-term contracts, but will not address or prejudge any arguments made in these proceedings.

Effect On Other Subsidiaries

At December 31, 2001, SET was due approximately $100 million from the ISO for which the company believes adequate reserves have been recorded. The collection of these receivables may depend on satisfactory resolution of the financial difficulties being experienced by the IOUs as a result of the California electric industry situation described above.

NOTE 15. OTHER REGULATORY MATTERS

Gas Industry Restructuring

The natural gas industry in California experienced an initial phase of restructuring during the 1980s, but the CPUC did not make major changes after the early 1990s. In January 1998, the CPUC released a staff report initiating a project to assess the current market and regulatory framework for California's natural gas industry. In July 1999, after hearings, the CPUC issued a decision stating which natural gas regulatory changes it found most promising, encouraging parties to submit settlements addressing those changes, and providing for further hearings if necessary.

On December 11, 2001, the CPUC issued a decision adopting much of a settlement that had been submitted in 2000 by the California utilities and approximately 30 other parties representing all segments of the gas industry in Southern California, but which was opposed by other parties. The CPUC decision adopts the following provisions: a system for shippers to hold firm, tradable rights to capacity on SoCalGas' major gas transmission lines with SoCalGas' shareholders at risk for whether market demand for these rights will cover the cost of these facilities; a further unbundling of SoCalGas' storage services giving SoCalGas greater upward pricing flexibility (except for storage service for core customers) but with increased shareholder risk for whether market demand will cover storage costs; new balancing services including separate core and noncore balancing provisions; a reallocation among customer classes of the cost of interstate pipeline capacity held by SoCalGas and an unbundling of interstate capacity for gas marketers serving core customers; and the elimination of noncore customers' option to obtain gas supply service from SoCalGas and SDG&E. The CPUC modified the settlement to provide increased protection against the exercise of market power by persons who would acquire rights on the SoCalGas gas transmission system. The CPUC also rejected certain aspects of the settlement that would have provided more options for gas marketers serving core customers.

The CPUC is still considering the schedule for implementation of these regulatory changes, but it is expected that most of the changes will be implemented during 2002.

The California utilities believe the decision will make gas service more reliable, efficient and better tailored to the desires of customers. The decision is not expected to negatively impact the California utilities' earnings.

Performance-Based Regulation (PBR)

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC has been directing utilities to use PBR. PBR has replaced the general rate case and certain other regulatory proceedings for the California utilities. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and productivity goals, as well as cost reductions, rather than relying solely on expanding utility plant in a market where a utility already has a highly developed infrastructure.

In April 2001, SDG&E filed its 2000 PBR report with the CPUC. For 2000, SDG&E exceeded all six performance indicator benchmarks, resulting in a request for a total net reward of $11.7 million. The CPUC has not yet approved this report and these awards have not been recorded. In addition, SDG&E achieved an actual 2000 rate of return (applicable only to electric distribution and gas transportation) of 8.74 percent, which is below the authorized 8.75 percent. This results in no sharing of earnings in 2000 under the PBR sharing mechanism (as described below).

The California utilities' PBR mechanisms were to have been in effect through December 31, 2002, at which time the mechanisms were to be updated. That update was to include, among other things, a re-examination of the California utilities' reasonable costs of operation to be allowed in rates. The PBR and Cost of Service (COS) cases for the California utilities were both due to be filed on December 21, 2001. However, both the California utilities' PBR/COS cases were delayed by an October 10, 2001 CPUC decision such that the resulting rates would be effective in 2004 instead of 2003. The decision also denies the California utilities' request to continue equal sharing between ratepayers and shareholders of the estimated savings for the merger discussed in Note 1 and, instead, orders that all of the estimated 2003 merger savings go to ratepayers. The portion to be refunded to electric ratepayers was credited to the TCBA during the fourth quarter of 2001, based on the NPV in 2001 of the savings for 2003. Merger savings related to 2001 and 2002 also were credited. The combined NPV was $39 million. Merger savings allocable to gas ratepayers will be refunded through once-a-year bill credits, as has been the case.

Key elements of the current mechanisms include an annual indexing mechanism that adjusts rates by the inflation rate less a productivity factor and other adjustments to accommodate major unanticipated events, a sharing mechanism with customers that applies to earnings that exceed the authorized rate of return on rate base, rate refunds to customers if service quality deteriorates or awards if service quality exceeds set standards, and a change in authorized rate of return and customer rates if interest rates change by more than a specified amount. The SoCalGas rate change is triggered if the 12-month trailing average of actual market interest rates increases or decreases by more than 150 basis points and is forecasted to continue to vary by at least 150 basis points for the next year. The SDG&E rate change is triggered by a six-month trailing average and a 100-basis-point change in interest rates. If these events occur, there would be an automatic adjustment of rates for the change in the cost of capital according to a formula which applies a percentage of the change to various capital components.

Gas Cost Incentive Mechanism

The Gas Cost Incentive Mechanism (GCIM) evaluates SoCalGas' natural gas purchases by comparing their cost with the average price of 30-day firm spot supplies in the basins in which SoCalGas purchases natural gas. The mechanism permits full recovery of all costs within a tolerance band above the benchmark price and refunds all savings within a tolerance band below the benchmark price. The costs or savings outside the tolerance band are shared between customers and shareholders. The CPUC approved the use of natural gas futures for managing risk associated with the GCIM. SoCalGas enters into natural gas futures contracts in the open market to mitigate risk and better manage natural gas costs.

Shareholder awards associated with the GCIM normally are recorded to SoCalGas' Purchased Gas Balancing Account after the close of the GCIM period, which covers the utility's gas supply operations for the twelve months ended March 31. These awards are not included in earnings until receipt of CPUC approval. In May 2001, the CPUC approved a $10 million shareholder award for GCIM Year Six ended March 31, 2000, and the CPUC is addressing whether the GCIM should be extended and, if so, whether it should be with or without modifications. The CPUC's Energy Division had previously issued an evaluation report recommending the continuation of the GCIM with modifications. In July 2001, SoCalGas, the CPUC's Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN), a consumer-advocacy group, filed a Joint Motion for Adoption of Settlement Agreement to resolve all Phase 2 issues and to continue the GCIM with modifications. On March 5, 2002, a proposed decision was issued that, if adopted by the CPUC, would approve the settlement agreement and continue the mechanism, applying the modified GCIM beginning with the GCIM Year Seven (see below). A CPUC decision is expected by the third quarter of 2002.

In June 2001, SoCalGas filed its annual GCIM application with the CPUC requesting a shareholder award of $106 million for the GCIM Year Seven ended March 31, 2001. Notwithstanding this request the July 2001 Settlement Agreement among SoCalGas, the ORA and TURN would retroactively reduce the award request to $31 million. This proceeding is separate from the Phase 2 proceeding discussed above and final CPUC approval is not expected until early 2003.

Demand Side Management Awards

In recent years, the IOUs have participated in a CPUC program whereby they could earn awards for operating and/or administering energy-conservation efforts involving their retail customers. The California utilities have participated in these programs and have consistently achieved significant earnings therefrom. As part of the CPUC's review of the program, a draft decision is proposing that the program be reduced in scope and that award potentials for the IOUs be eliminated. An alternate proposal would maintain the award concept, but the potential awards would probably be reduced. The CPUC is scheduled to review both proposals at its March 21, 2002 meeting.

Biennial Cost Allocation Proceeding (BCAP)

Rates to recover the changes in the cost of natural gas transportation services are determined in the BCAP. The BCAP adjusts rates to reflect variances in customer demand from estimates previously used in establishing customer natural gas transportation rates. The mechanism substantially eliminates the effect on income of variances in market demand and natural gas transportation costs. SoCalGas filed its 2003 BCAP on September 21, 2001 and SDG&E filed its 2003 BCAP on October 5, 2001.

On April 20, 2000, the CPUC issued a decision on the 1999 BCAP, adopting overall decreases in natural gas revenues of $210 million for SoCalGas and $37 million for SDG&E for transportation rates effective June 1, 2000. For SoCalGas, there is a return to 75/25 (customer/shareholder) balancing account treatment for noncore transportation revenues, excluding certain transactions. In addition, unbundled noncore storage revenues are balanced 50/50 between customers and shareholders. Since the decreases reflect anticipated changes in corresponding costs, they have no effect on net income.

Cost Of Capital

SoCalGas is authorized to earn a rate of return on common equity (ROE) of 11.6 percent and a 9.49 percent return on rate base (ROR), the same as in 2001 and 2000. These rates will continue to be effective until the next periodic review by the CPUC unless interest-rate changes are large enough to trigger an automatic adjustment prior thereto, as discussed above under "Performance-Based Regulation." For SDG&E, electric industry restructuring has changed the method of calculating the utility's annual cost of capital. In June 1999, the CPUC adopted a 10.6 percent ROE and an 8.75 percent ROR for SDG&E's electric distribution and natural gas businesses. These rates remain in effect through 2002. The electric-transmission cost of capital is determined under a separate FERC proceeding. SDG&E is required to file an application by May 8, 2002, addressing ROE, ROR and capital structure for 2003. The application will, among other things, consider the recent and ongoing financial impacts on SDG&E of electric industry restructuring.

Utility Integration

On September 20, 2001 the CPUC approved Sempra Energy's request to integrate the management teams of the California utilities. The decision retains the separate identities of each utility and is not a merger. Instead, utility integration is a reorganization that consolidates senior management functions of the two utilities and returns to the utilities a significant portion of shared support services currently provided by Sempra Energy's centralized corporate center. Once implementation is completed, the integration is expected to result in more efficient and effective operations.

In a related development, a CPUC draft decision would allow the California utilities to combine their natural gas procurement activities. The CPUC is scheduled to act on the draft decision at its April 4, 2002 meeting.

CPUC Investigation of Energy-Utility Holding Companies

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. Among the matters to be considered in the investigation are utility dividend policies and practices and obligations of the holding companies to provide financial support for utility operations under the agreements with the CPUC permitting the formation of the holding companies. On January 11, 2002, the CPUC issued a decision to clarify under what circumstances, if any, a holding company would be required to provide financial support to its utility subsidiaries. The CPUC broadly determined that it would require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to cover their utility subsidiaries' capital requirement, as the IOUs have previously acknowledged in connection with the holding companies' formations. On January 14, 2002, the CPUC ruled on jurisdictional issues, deciding that the CPUC had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed. The company has filed to request rehearing on the issues.

NOTE 16. SEGMENT INFORMATION

The company, primarily an energy services company, has three separately managed reportable segments comprised of SoCalGas, SDG&E and SET. The two California utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SDG&E provides electric and natural gas service to San Diego and southern Orange counties. SoCalGas is a natural gas distribution utility, serving customers throughout most of Southern California and part of central California. SET is based in Stamford, Connecticut, and is engaged in wholesale trading and marketing of natural gas, electricity, petroleum, petroleum products and other commodities in the United States, Canada, Europe and Asia. The accounting policies of the segments are described in Note 2, and segment performance is evaluated by management based on reported net income. Intersegment transactions are recorded the same as sales or transactions with third parties. Utility transactions are primarily based on rates set by the CPUC and FERC.

(Dollars in millions)	Years ended December 31, 2001	2000	1999
OPERATING REVENUES			
Southern California Gas	**$3,716**	$2,854	$2,569
San Diego Gas & Electric	**2,313**	2,671	2,207
Sempra Energy Trading	**1,003**	795	450
Intersegment revenues	**(31)**	(65)	(72)
All other	**1,028**	782	206
Total	**$8,029**	$7,037	$5,360
INTEREST INCOME			
Southern California Gas	**$ 22**	$ 27	$ 16
San Diego Gas & Electric	**21**	51	40
Sempra Energy Trading	**11**	8	3
Intersegment interest	**(50)**	(106)	(86)
All other	**79**	88	82
Total interest income	**83**	68	55
Equity in earnings of unconsolidated subsidiaries	**12**	62	(5)
Sundry income (loss)	**(5)**	(3)	—
Total other income	**$ 90**	$ 127	$ 50
DEPRECIATION AND AMORTIZATION			
Southern California Gas	**$ 268**	$ 263	$ 260
San Diego Gas & Electric (See Note 14)	**207**	210	561
Sempra Energy Trading	**27**	32	29
All other	**77**	58	29
Total	**$ 579**	$ 563	$ 879
INTEREST EXPENSE			
Southern California Gas	**$ 68**	$ 74	$ 60
San Diego Gas & Electric	**92**	118	120
Sempra Energy Trading	**14**	18	15
Intersegment interest	**(50)**	(106)	(86)
All other	**199**	182	120
Total	**$ 323**	$ 286	$ 229
INCOME TAX EXPENSE (BENEFIT)			
Southern California Gas	**$ 169**	$ 183	$ 182
San Diego Gas & Electric	**141**	144	126
Sempra Energy Trading	**87**	63	(7)
All other	**(184)**	(120)	(122)
Total	**$ 213**	$ 270	$ 179
NET INCOME (LOSS)			
Southern California Gas	**$ 207**	$ 206	$ 200
San Diego Gas & Electric	**177**	145	193
Sempra Energy Trading	**196**	155	19
All other	**(62)**	(77)	(18)
Total	**$ 518**	$ 429	$ 394

(Dollars in millions)	At December 31 or for the years ended December 31 **2001**	2000	1999
ASSETS			
Southern California Gas	**$ 3,762**	$ 4,128	$ 3,452
San Diego Gas & Electric	**5,444**	4,734	4,366
Sempra Energy Trading	**3,114**	4,689	1,981
All other	**2,836**	1,989	1,325
Total	**$15,156**	$15,540	$11,124
CAPITAL EXPENDITURES			
Southern California Gas	**$ 294**	$ 198	$ 146
San Diego Gas & Electric	**307**	324	245
Sempra Energy Trading	**45**	22	26
All other	**422**	215	172
Total	**$ 1,068**	$ 759	$ 589
GEOGRAPHIC INFORMATION			
Long-lived assets			
United States	**$ 6,516**	$ 6,071	$ 5,857
Latin America	**836**	911	701
Canada	**24**	23	—
Europe	**10**	9	—
Total	**$ 7,386**	$ 7,014	$ 6,558
Operating revenues			
United States	**$ 7,468**	$ 6,700	$ 5,280
Latin America	**280**	154	16
Europe	**250**	158	62
Canada	**15**	14	2
Asia	**16**	11	—
Total	**$ 8,029**	$ 7,037	$ 5,360

QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarter ended (Dollars in millions except per-share amounts)	March 31	June 30	September 30	December 31
2001				
Operating revenues	**$3,242**	**$1,900**	**$1,510**	**$1,377**
Operating expenses	**2,870**	**1,628**	**1,291**	**1,247**
Operating income	**$ 372**	**$ 272**	**$ 219**	**$ 130**
Net income	**$ 178**	**$ 137**	**$ 96**	**$ 107**
Average common shares outstanding (diluted)	**203.0**	**206.0**	**206.6**	**206.0**
Net income per common share (diluted)	**$ 0.88**	**$ 0.66**	**$ 0.46**	**$ 0.52**
2000				
Operating revenues	$1,442	$1,510	$1,806	$2,279
Operating expenses	1,201	1,288	1,619	2,046
Operating income	$ 241	$ 222	$ 187	$ 233
Net income	$ 113	$ 110	$ 110	95
Average common shares outstanding (diluted)	228.4	201.5	201.5	202.7
Net income per common share (diluted)	$ 0.49	$ 0.55	$ 0.55	$ 0.47

The sum of the quarterly amounts may not equal the annual totals due to rounding. Certain amounts are classified differently between operating revenues and operating expenses than as they were presented in the Quarterly Reports on Form 10-Q.

QUARTERLY COMMON STOCK DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2001				
Market price				
High	**$23.94**	**$28.61**	**$28.00**	**$26.68**
Low	**$17.31**	**$21.98**	**$23.25**	**$22.00**
2000				
Market price				
High	$19.25	$19.25	$21.00	$24.88
Low	$16.25	$16.19	$17.00	$19.38

Dividends declared were $0.25 in each quarter.

Sempra Energy’s annual report to the Securities and Exchange Commission (Form 10-K) is available to shareholders at no charge by writing to Shareholder Services at 101 Ash Street, San Diego, CA 92101.