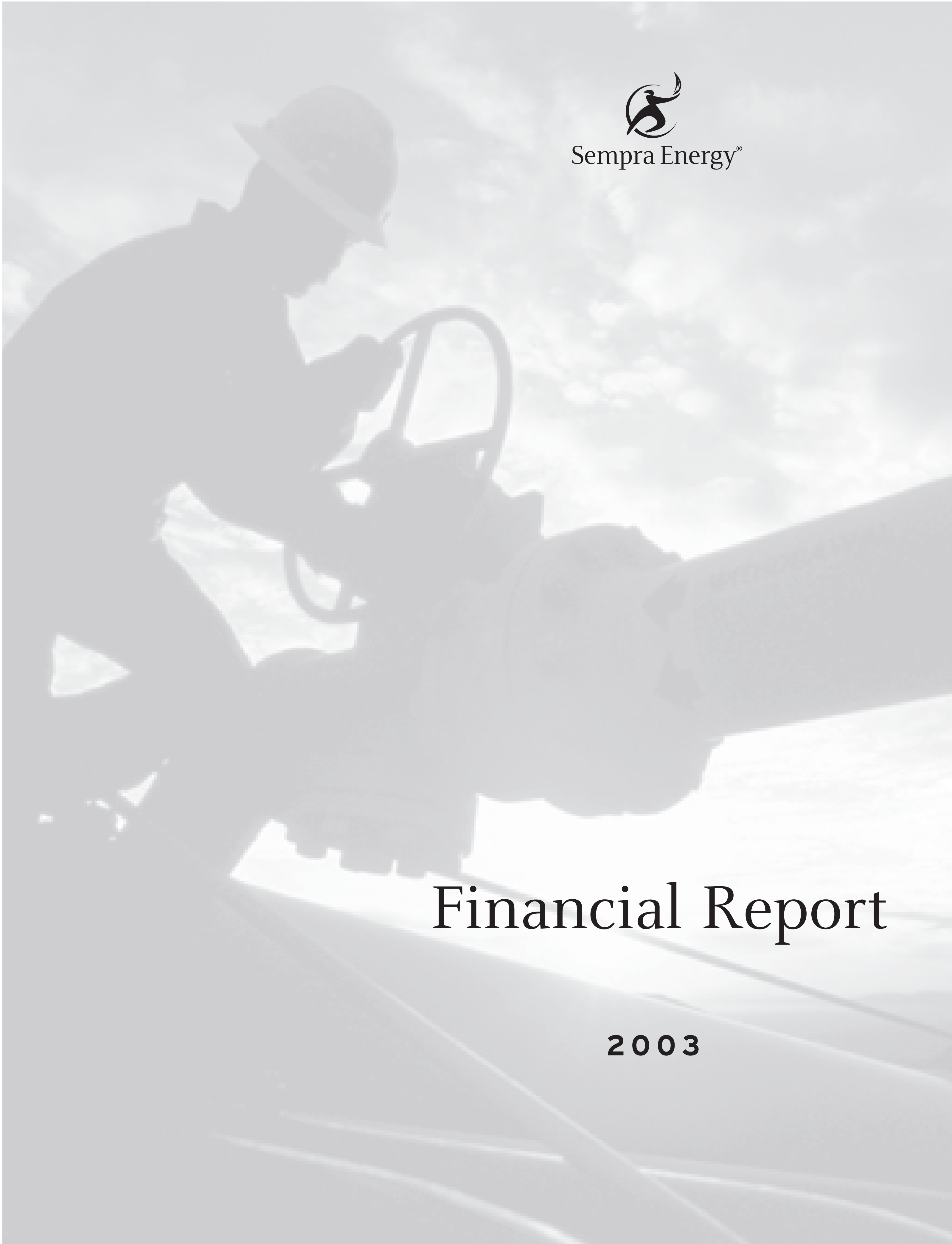


Sempra Energy®

Financial Report

2003

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

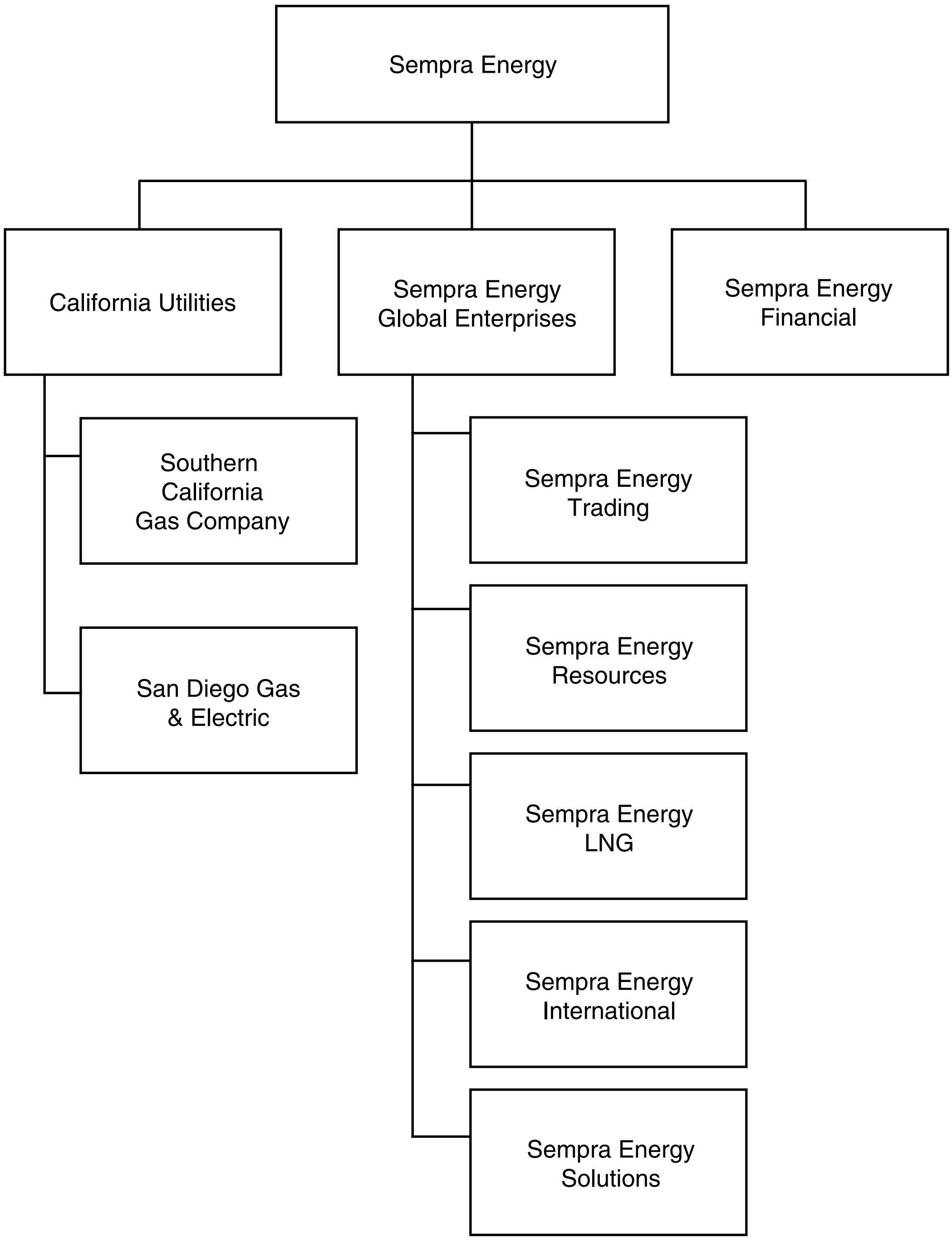
INTRODUCTION

This section includes management's discussion and analysis of operating results from 2001 through 2003, and provides information about the capital resources, liquidity and financial performance of Sempra Energy and its subsidiaries (collectively referred to as "the company"). This section also focuses on the major factors expected to influence future operating results and discusses investment and financing activities and plans. It should be read in conjunction with the Consolidated Financial Statements included in this Financial Report.

OVERVIEW

Sempra Energy

Sempra Energy is a Fortune 500 energy services holding company. Its business units provide a wide spectrum of value-added electric and natural gas products and services to a diverse range of customers. Operations are divided between delivery services, which are comprised of the California utility subsidiaries, Sempra Energy Global Enterprises (Global) and Sempra Energy Financial as described below.



Summary descriptions of the operating business units are provided below and further detail is provided throughout this section of the Financial Report.

The major events during 2003 affecting the results for the year and future years (and the page number where each is discussed) include the following:

- Favorable resolution of significant income-tax issues which increased 2003 earnings by $118 million (67);
- Favorable decisions, subject to appeal, upholding Sempra Energy Resources' (SER) contract with the California Department of Water Resources (DWR) (100);
- California Public Utilities Commission (CPUC) settlement subject to appeal, relating to San Diego Gas & Electric's (SDG&E) intermediate-term power-purchase contracts and recognition of the related $65 million after-tax gain (101);
- Rate-setting process for 2004 and future years nearing resolution for Southern California Gas Company (SoCalGas) and SDG&E (88);
- Completion of construction for generating plants by the company's generation subsidiary (18);
- Entry into the liquefied natural gas (LNG) business in Baja California, Mexico and in Louisiana (55);
- The end of incentive-pricing ratemaking for the San Onofre Nuclear Generation Station (SONGS), 20% owned by SDG&E (86);
- Continuing preliminary proceedings related to a claim by the company's international business unit for compensation from the Argentine government for changes in natural gas tariffs (57);
- Continuing legal proceedings concerning anti-trust claims made against the company, SDG&E and SoCalGas (100);
- Write down of the carrying values of Frontier Energy and Atlantic Electric & Gas Limited (AEG) (51); and
- Application of a new accounting principle, requiring consolidation of two affiliates (53).

The California Utilities

As of December 31, 2003, SoCalGas and SDG&E (the California Utilities) served over 22 million consumers. Natural gas service was provided throughout Southern California and portions of central California through over 6.2 million meters. Electric service was provided throughout San Diego County and portions of Orange County, both in Southern California, through 1.3 million meters.

Sempra Energy Global Enterprises (Global)

Global is a holding company for most of the subsidiaries of Sempra Energy that are not subject to California utility regulation.

Global's principal subsidiaries provide the following energy-related products and services:

- Sempra Energy Trading (SET) is a wholesale trader of physical and financial energy products, including natural gas, power, crude oil and other commodities, and a trader and wholesaler of metals, serving a broad range of customers;
- SER acquires, develops and operates power plants for the competitive market;
- Sempra Energy LNG Corp. (SELNG) is developing regasification terminals for LNG;
- Sempra Energy International (SEI) engages in energy-infrastructure projects outside the United States and, as of December 31, 2003, had interests in companies that provide natural gas or electricity services to over 2.8 million customers in Argentina, Chile, Mexico and Peru and in two small natural gas distribution utilities in the eastern United States; and

- Sempra Energy Solutions (SES) provides energy-related products and services on a retail basis, including commodity sales to electricity and natural gas consumers and energy efficiency engineering services.

Sempra Energy Financial (SEF)

In order to reduce Sempra Energy's income taxes, SEF invests in limited partnerships which own 1,300 affordable-housing properties throughout the United States and holds an interest in a limited partnership that produces synthetic fuel from coal.

RESULTS OF OPERATIONS

Overall Operations

Net income was $649 million in 2003, a 9.8% increase over 2002, and earnings per diluted share was $3.03, an increase of 5.6%. The percentage increase in earnings per diluted share was less than the percentage increase in earnings due to the issuance of shares needed to finance the company's expanded Global business.

The following chart shows net income and diluted earnings per share for each of the five years following the formation of the company in 1998.

(Dollars in millions, except per share amounts)	Net Income	Earnings Per Share
2003	**$649**	**$3.03**
2002	$591	$2.87
2001	$518	$2.52
2000	$429	$2.06
1999	$394	$1.66

Although operating income was less in 2003 than in 2002, there were many unusual items that affect this comparison. The following table summarizes the major factors affecting the comparison of net income and operating income for 2002 and 2003. The numbers in parentheses are the page numbers where each item is discussed herein.

(Dollars in millions)	Net Income	Operating Income
2002	$591	$987
Extraordinary item in 2002 (47)	(16)	—
Merger savings in 2002 (89)	(25)	(42)
Income-tax settlements in 2002 (11)	(25)	—
California energy crisis litigation costs in 2002 (9)	13	23
	538	968
Income-tax settlements in 2003 (67)	**118**	**—**
SDG&E power contract settlement in 2003 (101)	**65**	**116**
Impairment of Frontier Energy assets in 2003 (51)	**(47)**	**(77)**
Impairment of AEG assets in 2003 (51)	**(21)**	**(24)**
California energy crisis litigation costs and SoCalGas sublease loss in 2003 (100)	**(49)**	**(85)**
SoCalGas' natural gas procurement awards in 2003 (90)	**29**	**49**
Changes in accounting principles in 2003:		
Repeal of EITF 98-10 (52)	**(29)**	—
Adoption of FIN 46 (53)	**(17)**	—
2003 impact of the repeal of EITF 98-10 (52)	**9**	**15**
Operations (2003 compared to 2002)	**53**	**(23)**
2003	**$649**	**$939**

California Utility Operations

To understand the operations and financial results of the California Utilities, it is important to understand the ratemaking procedures to which they are subject.

The California Utilities are subject to various regulatory bodies and rules at the national, state and local levels. The primary California body is the CPUC which regulates utility rates and operations. The primary national bodies are the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC). The FERC regulates interstate transportation of natural gas and electricity and various related matters. The NRC regulates nuclear generating plants. Local regulators and municipalities govern the placement of utility assets, including natural gas pipelines and electric lines. Other business units are also subject to regulation including, as the case may be, the FERC, various state commissions, local bodies, and various similar bodies in countries other than the United States.

California's electric utility industry was significantly affected by California's restructuring of the industry during 2000-2001. Beginning in mid-2000 and continuing into 2001, supply/demand imbalances and a number of other factors resulted in abnormally high electric commodity costs, leading to several legislative and regulatory responses, including a ceiling imposed on the cost of the electric commodity that SDG&E could pass on to its small-usage customers. To obtain adequate supplies of electricity, beginning in February 2001 and continuing through December 31, 2002, the DWR began purchasing power to fulfill the full net short position of the investor-owned utilities (IOUs), consisting of all electricity requirements of the IOUs' customers other than that provided by their existing generating facilities or their previously existing purchased-power contracts.

Beginning on January 1, 2003, SDG&E and the other IOUs resumed their electric commodity procurement function. In addition, the CPUC established the allocation of the power purchased by the DWR under long-term contracts for the IOUs' customers and the related cost responsibility among the IOUs for that power. This is discussed further in Note 13 of the notes to Consolidated Financial Statements.

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. Restructuring is again being considered, as discussed in Note 14 of the notes to Consolidated Financial Statements.

See additional discussion of these matters under "Factors Influencing Future Performance" and in Notes 13 and 14 of the notes to Consolidated Financial Statements.

Natural Gas Revenue and Cost of Natural Gas. Natural gas revenues increased to $4.0 billion in 2003 from $3.3 billion in 2002, and the cost of natural gas increased to $2.1 billion in 2003 from $1.4 billion in 2002. Additionally, natural gas revenues increased to $1.0 billion for the three months ended December 31, 2003 from $971 million for the same period in 2002, and the corresponding cost of natural gas increased to $542 million in 2003 from $436 million in 2002. These changes were primarily attributable to natural gas price increases. For the year, this was partially offset by reduced volumes. Revenues also increased due to approved performance awards recognized during 2003. See discussion of performance awards in Note 14 of the notes to Consolidated Financial Statements.

Under the current regulatory framework, the cost of natural gas purchased for customers and the variations in that cost are passed through to the customers on a substantially concurrent basis. However, SoCalGas' Gas Cost Incentive Mechanism (GCIM) allows SoCalGas to share in the savings or costs from buying natural gas for customers below or above monthly benchmarks. 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. In addition, SDG&E's natural gas procurement Performance-Based Regulation (PBR) mechanism provides an incentive mechanism by measuring SDG&E's procurement of natural gas against a benchmark price comprised of monthly natural gas indices, resulting in shareholder rewards for costs achieved below the benchmark and shareholder penalties when costs exceed the benchmark. See further discussion in Notes 1 and 14 of the notes to Consolidated Financial Statements.

Natural gas revenues decreased to $3.3 billion in 2002 from $4.4 billion in 2001, and the cost of natural gas distributed decreased to $1.4 billion in 2002 from $2.5 billion in 2001. The decrease in natural gas revenues was primarily due to lower natural gas prices and decreased transportation charges related to electric generation plants and the North Baja pipeline's beginning of service in September 2002 (see Note 15 of the notes to Consolidated Financial Statements). The decrease in the cost of natural gas was primarily due to lower average natural gas commodity prices. For the fourth quarter, natural gas revenues increased to $971 million in 2002 from $773 million in 2001, and the cost of natural gas distributed increased to $436 million in 2002 from $319 million in 2001 due primarily to increased natural gas prices.

Electric Revenue and Cost of Electric Fuel and Purchased Power. Electric revenues increased to $1.8 billion in 2003 from $1.3 billion in 2002, and the cost of electric fuel and purchased power increased to $0.5 billion in 2003 from $0.3 billion in 2002. Additionally, for the fourth quarter electric revenues increased to $419 million in 2003 from $320 million in 2002, and the cost of electric fuel and purchased power increased to $113 million in 2003 from $76 million in 2002. These changes were attributable to several factors, including the effect of the DWR's purchasing the net short position of SDG&E during 2002, higher electric commodity costs and volumes in 2003, and the increase in authorized 2003 distribution revenue. In addition, the increase in revenue was due to the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts and higher PBR awards during the third quarter or 2003.

Electric revenues decreased to $1.3 billion in 2002 from $1.7 billion in 2001, and the cost of electric fuel and purchased power decreased to $0.3 billion in 2002 from $0.8 billion in 2001. These decreases were primarily due to the DWR's purchasing SDG&E's net short position for a full year in 2002 and the effect of lower electric commodity costs and decreased off-system sales. For the fourth quarter, electric revenues increased to $320 million in 2002 from $284 million in 2001, and the cost of electric fuel and purchased power decreased to $76 million in 2002 from $87 million in 2001. The increase in electric revenues was due primarily to higher electric distribution and transmission revenue as well as additional revenues from the Incremental Cost Incentive Pricing (ICIP) mechanism, while the decrease in cost of electric fuel and purchased power was due primarily to a decrease in average electric commodity costs. Refer to Note 13 of the notes to Consolidated Financial Statements for further discussion of ICIP and SONGS.

The tables below summarize the California Utilities' natural gas and electric volumes and revenues by customer class for the years ended December 31, 2003, 2002 and 2001.

NATURAL GAS SALES, TRANSPORTATION & EXCHANGE
(Dollars in millions, volumes in billion cubic feet)

	Natural Gas Sales		Transportation & Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
2003:						
Residential	**273**	**$2,479**	**2**	**$ 7**	**275**	**$2,486**
Commercial and industrial	**121**	**863**	**277**	**189**	**398**	**1,052**
Electric generation plants	**—**	**3**	**241**	**79**	**241**	**82**
Wholesale	**—**	**—**	**20**	**4**	**20**	**4**
	394	**$3,345**	**540**	**$279**	**934**	**3,624**
Balancing accounts and other						**386**
Total						**$4,010**
2002:						
Residential	289	$2,089	2	$ 8	291	$2,097
Commercial and industrial	117	635	294	183	411	818
Electric generation plants	—	—	264	43	264	43
Wholesale	—	—	16	12	16	12
	406	$2,724	576	$246	982	2,970
Balancing accounts and other						293
Total						$3,263
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

ELECTRIC TRANSMISSION AND DISTRIBUTION
(Dollars in millions, volumes in million kilowatt hours)

	2003		2002		2001	
	Volumes	**Revenue**	Volumes	Revenue	Volumes	Revenue
Residential	**6,702**	**$ 731**	6,266	$ 649	6,011	$ 775
Commercial	**6,263**	**674**	6,053	633	6,107	753
Industrial	**1,976**	**161**	1,883	160	2,792	325
Direct access	**3,322**	**87**	3,448	117	2,464	84
Street and highway lighting	**91**	**11**	88	9	89	10
Off-system sales	**8**	**—**	5	—	413	88
	18,362	**1,664**	17,743	1,568	17,876	2,035
Balancing and other		**123**		(286)		(359)
Total		**$1,787**		$1,282		$1,676

As explained in Note 13 of the notes to Consolidated Financial Statements, commodity-related revenues from the DWR's purchasing of SDG&E's net short position or from the DWR's allocated contracts are not included in revenue. However, the associated volumes and distribution revenue are included herein.

Other Operating Revenues and Cost of Sales. These tables provide a breakdown of other operating revenues and cost of sales by business unit.

(Dollars in millions)	**2003**	2002	2001
OPERATING REVENUES			
Sempra Energy Trading	**$1,144**	$ 821	$1,047
Sempra Energy Resources	**671**	349	178
Sempra Energy International	**208**	176	289
Sempra Energy Solutions	**175**	177	180
Total Global Enterprises	**2,198**	1,523	1,694
Parent and Other*	**(108)**	(20)	(11)
Total	**$2,090**	$1,503	$1,683
COST OF SALES			
Sempra Energy Trading	**$ 542**	$ 293	$ 320
Sempra Energy Resources	**433**	218	185
Sempra Energy International	**166**	148	257
Sempra Energy Solutions	**65**	56	92
Total Global Enterprises	**1,206**	715	854
Parent and Other*	**(2)**	(6)	19
Total	**$1,204**	$ 709	$ 873

* Includes certain intercompany eliminations recorded in consolidation.

For the fourth quarters of 2003 and 2002, revenues increased to $598 million from $409 million in 2002 and costs increased to $318 million from $206 million. These increases and the annual increases shown above were primarily due to higher revenues at SET as the result of increased volumes and volatility in the energy commodity markets, as well as increased revenues from SER's resumption of contract sales of electricity to the DWR in April 2002 and sales by its Twin Oaks power plant purchased in the fourth quarter of 2002.

The decreases in revenues and costs in 2002 from 2001 were primarily due to reduced SEI revenues as a result of decreased natural gas prices at its Mexican subsidiaries and lower activity at SET as a result of decreased volatility in energy commodity markets and lower energy commodity prices, partially offset by increased activity from acquisitions made during 2002. These decreases were partially offset by the increase in SER's sales to the DWR that commenced in June 2001 through September 2001 at below cost, and resumed in April 2002 at favorable contract rates under its long-term contract.

For the fourth quarters of 2002 and 2001, revenues increased to $409 million from $242 million in 2001 and costs increased to $206 million from $174 million. The increases were primarily due to increased activity at SET as a result of higher volatility in energy commodity markets as well as increased SER sales.

Other Operating Expenses. This table provides a breakdown of operating expenses by business unit.

(Dollars in millions)	**2003**	2002	2001
OPERATING EXPENSES			
California Utilities			
Southern California Gas Company	**$ 954**	$ 872	$ 792
San Diego Gas & Electric	**637**	560	491
Total Utilities	**1,591**	1,432	1,283
Global Enterprises			
Sempra Energy Trading	**374**	304	370
Sempra Energy Resources	**93**	44	21
Sempra Energy International	**120**	49	70
Sempra Energy Solutions	**71**	66	68
Total Global Enterprises	**658**	463	529
Parent and Other*	**38**	6	(52)
Total	**$2,287**	$1,901	$1,760

* Includes certain intercompany eliminations recorded in consolidation.

The increase at the California Utilities in 2003 from 2002 was primarily the result of a $75 million before-tax charge for litigation and for losses associated with a sublease of portions of the SoCalGas headquarters building, and increased labor and employee benefit costs. The non-recurring sublease losses pertain to pre-2003 transactions, but are charged against current operations because they are not material to annual financial statements. A smaller portion of the increase was due to the California fires, which primarily affected SDG&E and which are discussed in Note 14 of the notes to Consolidated Financial Statements. The fire costs are expected to be recovered in rates. General operating costs increased at SET due to the increased activity and a full year's activities for the businesses acquired in 2002, at SER due to the new power plants and at SEI due to the $77 million before-tax write-down of the carrying value of the assets of Frontier Energy, as described in Note 1 of the notes to Consolidated Financial Statements. In addition, operating costs increased due to a $24 million before-tax write-down of the carrying value of the assets of AEG and due to higher antitrust litigation costs at the Global companies. During 2002 the California Utilities recorded $23 million in litigation costs related to the California energy crisis.

For the 2003 and 2002 fourth quarters, other operating expenses increased to $656 million in 2003 ($474 million from the California Utilities) from $587 million in 2002 ($457 from the California Utilities). The increase was mainly due to increased operating costs at SDG&E, SET and SER as discussed above.

For the 2002 and 2001 fourth quarters, other operating expenses increased to $587 million from $394 million in 2001. This increase and the annual increase shown above was due primarily to increased operating costs at the California Utilities resulting largely from higher labor and employee benefits costs, litigation costs related to the California energy crisis, costs associated with SDG&E's nuclear generating facilities and balancing account costs at SoCalGas.

Other Income. Other income, primarily equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, was $26 million, $15 million and $3 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to increased equity earnings at SEI and other subsidiaries, and reduced balancing account interest expense, partially offset by lower operating results at SER's joint ventures resulting from business interruption insurance proceeds received in 2002 related to an outage at the El Dorado plant during 2001.

The increase in 2002 was primarily due to increased sales at the El Dorado power plant and the business interruption insurance proceeds, offset partially by lower 2002 equity earnings from international investments and the $19 million gain from SDG&E's sale of its property in Blythe, California in 2001.

Other income for the fourth quarter was a net loss of $12 million for 2003 compared to income of $9 million for 2002 and a loss of $12 million for 2001. The decrease in 2003 was due to decreased equity earnings from SEI as well as lower operating results at SER's joint ventures. The increase in 2002 was due primarily to lower net regulatory interest expense.

Interest Income. Interest income was $104 million, $42 million and $83 million in 2003, 2002 and 2001, respectively. $59 million of the increase in 2003 was due to the favorable resolution of income-tax issues with the Internal Revenue Service (IRS) in 2003. The decrease in 2002 compared to 2001 was due primarily to lower interest income on short-term investments.

Interest Expense. Interest expense was $308 million, $294 million and $323 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to the issuance of $1 billion of long-term notes in April 2002 and early 2003, and the reclassification of preferred dividends on mandatorily redeemable trust preferred securities and preferred stock of subsidiaries to interest expense as a result of the adoption of Statement of *Financial Accounting Standards (SFAS) 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity,"* on July 1, 2003 (see Note 1 of the notes to Consolidated Financial Statements). These increases were offset partially by the paydown of commercial paper and debt maturities at the California Utilities.

The decrease in 2002 was primarily due to an increase in capitalized interest related to construction projects, lower interest rates and the favorable effects of interest rate swaps. 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.

Interest expense for the fourth quarter was $85 million, $74 million and $63 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to the issuance of the $400 million of long-term notes, offset partially by the paydown of commercial paper and debt maturities at the California Utilities. The increase in 2002 was attributable to the issuance of $600 million of equity units by the company and $250 million of first mortgage bonds issued by SoCalGas, partially offset by debt maturities at the California Utilities.

Income Taxes. Income tax expense was $47 million, $146 million and $213 million in 2003, 2002 and 2001, respectively. The effective income tax rates were 6.3 percent, 20.2 percent and 29.1 percent, respectively. The changes in 2003 compared to 2002 were primarily due to the favorable resolution of income-tax issues in the fourth quarter of 2003 (which reduced income tax expense by $83 million) and a $39 million increase in income tax credits from synthetic fuel investments in 2003 (see discussion of Section 29 credits in Note 7), offset partially by a $25 million favorable resolution of income-tax issues at SDG&E in the second quarter of 2002. Income before taxes in 2003 included $59 million in interest income arising from the income tax settlement, resulting in an offsetting $24 million income tax expense. The decreases in income tax expense and in the effective income tax rates for 2002 compared to 2001 were primarily due to the favorable resolution of income-tax issues at SDG&E and increased income tax credits from synthetic fuel investments in 2002.

Income tax expense (benefit) for the fourth quarter was ($62) million in 2003 compared to $3 million in 2002, and ($40) million in 2001. The corresponding effective income tax (benefit) rates were (32.8) percent, 2.2 percent and (59.7) percent. The change in the 2003 quarter was due primarily to the resolution of the income-tax issues discussed above. The change in 2002 was due primarily to increased income before taxes, as well as the resolution in 2001 of prior-year tax issues. The low effective income tax rate in the 2002 quarter was primarily due to increased income tax credits from affordable-housing and synthetic fuel investments. These investments are discussed in Note 3 of the notes to Consolidated Financial Statements.

In connection with its affordable-housing investments, the company has unused tax credits dating back to 1999, which the company fully expects to utilize before their various expiration dates of 2019 to 2022. At December 31, 2003, the amount of these unused tax credits was $192 million. In addition, the company has $74 million of alternative minimum tax credits with no expiration date.

Net Income. Changes in net income between 2002 and 2003 are summarized in the table shown previously under “Overall Operations.”

Excluding the effects of the $16 million extraordinary item in 2002 (see Note 1 of the notes to Consolidated Financial Statements), the increase in net income in 2002 compared to 2001 was primarily due to improved results at SER, lower interest expense, the 2001 after-tax charge of $25 million for the surrender of SEI’s Nova Scotia natural gas distribution franchise and the effects of the income tax matters referred to above. These factors were partially offset by lower income in 2002 from SET and the $20 million after-tax gain on the sale of Energy America in 2001.

Net income for the fourth quarter of 2003 was $234 million, or $1.03 per diluted share of common stock in 2003, compared with $148 million, or $0.72 per diluted share of common stock in 2002, and $107 million, or $0.52 per diluted share of common stock in 2001. Net income for the fourth quarter of 2003 includes a $17 million charge for the cumulative effect of the change in accounting principle ($0.07 per diluted share of common stock). Net income for the fourth quarter of 2002 includes a $14 million extraordinary gain related to SET’s acquisitions ($0.07 per diluted share of common stock). Excluding the cumulative effect of the accounting change and the extraordinary item, the increase in quarterly earnings in 2003 compared to 2002 was mainly due to the favorable resolution of income tax issues at the California Utilities in 2003. The increase in 2002 compared to 2001 was primarily attributable to increased earnings at SET (from increased volatility in the energy markets and the contribution from the metals business) and increased earnings at SER from the DWR contract, offset partially by decreased profitability from SEI’s Argentine investments.

Book value per share was $17.17, $13.79 and $13.16, at December 31, 2003, 2002 and 2001, respectively. The increases in 2003 and 2002 were primarily the result of comprehensive income exceeding the dividends and, in 2003, the sale of additional shares of common stock for a per-share price in excess of its book value.

Net Income by Business Unit

(Dollars in millions)	Years ended December 31, **2003**	2002	2001
California Utilities			
Southern California Gas Company	**$ 209**	$212	$207
San Diego Gas & Electric	**334**	203	177
Total Utilities	**543**	415	384
Global Enterprises			
Sempra Energy Trading	**98**	126	196
Sempra Energy Resources	**94**	60	(27)
Sempra Energy International	**1**	26	25
Sempra Energy Solutions	**16**	21	1
Total Global Enterprises	**209**	233	195
Sempra Energy Financial	**41**	36	28
Parent and Other*	**(144)**	(93)	(89)
Total	**$ 649**	$591	$518

* Includes after-tax interest expense of $100 million, $70 million and $80 million in 2003, 2002 and 2001, respectively, and intercompany eliminations recorded in consolidation.

Southern California Gas Company

SoCalGas recorded net income of $209 million and $212 million in 2003 and 2002, respectively, and net income of $61 million and $45 million for the three-month periods ended December 31, 2003 and 2002, respectively. During 2003, net income was affected by the resolution of income-tax issues in the fourth quarter and the $29 million after-tax GCIM awards in the third quarter (see Note 14 of the notes to Consolidated Financial Statements for a discussion of GCIM awards), offset by a $32 million after-tax charge for litigation and for losses associated with a long-term sublease of portions of its headquarters building, and the end of sharing of merger savings (which positively impacted earnings by $17 million for the year ended December 31, 2002). The change for the quarter was due primarily to the resolution of the income-tax issues, offset partially by the end of sharing of merger savings (which positively impacted earnings by $4 million for the fourth quarter of 2002).

Net income for SoCalGas increased to $212 million in 2002 compared to $207 million in 2001 primarily due to decreased interest expense in 2002, offset partially by higher depreciation expense and the 2000 GCIM award recorded in 2001. Net income for the fourth quarter of 2002 decreased compared to the fourth quarter of 2001 due mainly to increased operating costs, partially offset by lower interest expense in 2002.

San Diego Gas & Electric

SDG&E recorded net income of $334 million and $203 million in 2003 and 2002, respectively, and net income of $128 million and $53 million for the fourth quarters of 2003 and 2002, respectively. The increase for the year was primarily due to the favorable resolution of income tax issues in the fourth quarter of 2003, which positively affected earnings by $79 million, income of $65 million after-tax related to the approved settlement of certain purchase power contracts (see Note 13 of the notes to Consolidated Financial Statements), higher earnings from PBR awards, and higher electric transmission and distribution revenue. These factors were partially offset by higher operating expenses, including litigation charges in the third quarter of 2003, the end of sharing of the merger savings (which positively impacted earnings by $8 million in 2002) and the $25 million favorable resolution of prior years' income-tax issues recorded in the second quarter of 2002. The change for the quarter was due to the resolution of the income tax issues and higher electric transmission and distribution revenue, offset partially by the end of sharing of the merger savings (which positively impacted earnings by $2 million for the 2002 quarter).

Net income increased to $203 million in 2002 from $177 million in 2001. The increase was primarily due to the $25 million after-tax benefit noted above and lower interest expense in 2002, partially offset by lower interest income in 2002 and the 2001 gain on the sale of SDG&E's Blythe property. Net income increased to $53 million for the fourth quarter of 2002, compared to $45 million for the corresponding period in 2001, primarily due to higher natural gas income, an increase in electric transmission and distribution revenues, and income tax adjustments in 2002, partially offset by the 2001 Blythe gain.

Sempra Energy Trading

SET recorded net income of $98 million in 2003 compared to $126 million and $196 million in 2002 and 2001, respectively. For the fourth quarter, SET recorded net income of $59 million in 2003 compared to $53 million and $10 million in 2002 and 2001, respectively. For purposes of comparison with the corresponding periods, net income for 2003 and 2002 would have been $117 million and $110 million if not for the repeal of *Emerging Issues Task Force (EITF) 98-10* in 2003 and the extraordinary gain recognized in 2002, both discussed in Note 1 of the notes to Consolidated Financial Statements. The repeal of EITF 98-10 adversely impacted SET's results by a cumulative effect adjustment of $28 million and positively impacted earnings by $9 million related to operations in 2003, including a $12 million positive adjustment for the three months ended December 31, 2003.

The decrease in net income in 2002 compared to 2001 was primarily due to greater revenues in 2001 resulting from higher volatility in energy commodity markets during the first half of 2001, partially offset by the extraordinary gain of $16 million, earnings from new acquisitions and increased synthetic fuel credits in 2002.

SET's net income included the impact of its synthetic fuel credits of $73 million, $39 million and $28 million in 2003, 2002 and 2001, respectively (see Note 7 of the notes to Consolidated Financial Statements), which contributed $23 million, $11 million and $5 million to earnings in 2003, 2002 and 2001, respectively.

A summary of SET's net unrealized revenues for trading activities follows:

	Years ended December 31,	
(Dollars in millions)	**2003**	2002
Balance at beginning of period	**$ 180**	$ 405
Cumulative effect adjustment	**(48)**	—
Additions	**755**	442
Realized	**(618)**	(667)
Balance at end of year	**$ 269**	$ 180

The estimated fair values for SET's net unrealized trading assets as of December 31, 2003, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	Fair Market Value at December 31, 2003	Scheduled Maturity (in months) 0-12	13-24	25-36	>36
Prices actively quoted	$163	$ 84	$ 68	$(14)	$25
Prices provided by other external sources	(4)	(6)	(2)	—	4
Prices based on models and other valuation methods	22	5	2	—	15
Over-the-counter (OTC) revenue*	181	83	68	(14)	44
Exchange contracts**	88	19	57	8	4
Total	$269	$102	$125	$ (6)	$48

* The present value of net unrealized revenues to be received from outstanding OTC contracts.

** Cash received associated with open Exchange contracts.

Sempra Energy Resources

SER recorded net income of $94 million in 2003 and $60 million in 2002, compared to a net loss of $27 million in 2001. Net income for 2003 includes the cumulative effect of the change in accounting principle, which positively impacted SER's earnings by $9 million. See further discussion of this in Note 1 of the notes to Consolidated Financial Statements. Excluding this impact, the change in 2003 was primarily due to increased volumes under SER's contract with the DWR, offset by increased interest expense and start-up expenses related to SER's new power plants. The increase in earnings for 2002 was primarily due to SER's sales to the DWR that resumed in April 2002 at contract rates under its long-term contract, compared to 2001 sales which were at less than cost, and the recovery in 2002 of business interruption insurance related to an outage at the El Dorado plant in 2001. Losses in 2001 arose from development costs of new generation projects and from selling power to the DWR at below cost.

Sempra Energy International

Net income for SEI was $1 million, $26 million and $25 million for 2003, 2002 and 2001, respectively. The change in 2003 was primarily due to the $50 million after-tax impairment of the carrying value of long-lived assets at Frontier Energy (one of SEI's small U.S. utilities), partially offset by increased equity earnings from its South American joint ventures and a full year of earnings from the Gasaducto Bajanorte pipeline in Mexico, which began operations in September 2002. The increase for 2002 was primarily due to the after-tax charge of $25 million in 2001 following the surrender of the natural gas distribution franchise in Nova Scotia, partially offset by reduced profitability from SEI's Argentine subsidiaries in 2002. A discussion of the Argentine economic issue is included in Notes 1 and 3 of the notes to Consolidated Financial Statements.

Sempra Energy Solutions

SES recorded net income of $16 million in 2003, $21 million in 2002 and $1 million in 2001. The change in 2003 was primarily due to reduced profits from retail commodity sales, caused by higher wholesale energy prices' making it more difficult for non-utility energy suppliers to offer prices significantly below utility energy prices. The increase in net income from 2001 to 2002 was primarily due to increased commodity sales. In delivering electric and natural 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' net unrealized revenues from trading activities follows:

(Dollars in millions)	Years ended December 31, 2003	2002
Balance at beginning of period	**$ 90**	$ 55
Cumulative effect adjustment	**(2)**	—
Additions	**75**	90
Realized	**(85)**	(55)
Balance at end of year	**$78**	$ 90

The estimated fair values for SES' net unrealized trading assets as of December 31, 2003, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	Fair Market Value at December 31, 2003	Scheduled Maturity (in months) 0-12	13-24	25-36	>36
Exchange contracts	$ 1	$ 1	$—	$—	$—
Prices actively quoted	77	44	18	10	5
Total	$78	$45	$18	$10	$ 5

Sempra Energy Financial

SEF recorded net income of $41 million in 2003, $36 million in 2002 and $28 million in 2001. The increase in 2003 was due to lower amortization expense, partially offset by increased equity losses from certain investments. The increase in 2002 was due to higher synthetic fuel (Section 29) income tax credits compared to 2001.

See discussion of Section 29 income tax credits in Note 7 of the notes to Consolidated Financial Statements. Whether SEF will invest in additional affordable-housing properties will depend on Sempra Energy's income tax position.

Parent and Other

Net losses for Parent and Other were $144 million, $93 million and $89 million in 2003, 2002 and 2001, respectively. The increase in 2003 was due to the $26 million negative after-tax impact of the cumulative effect of a change in accounting principle, the $21 million after-tax write down of the carrying value of the assets of AEG and higher interest expense as a result of the issuance of $1 billion of long-term notes in late 2002 and early 2003. The adoption of *Financial Accounting Standards Board* (*FASB) Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities"* and the resulting consolidation of AEG is discussed in Note 1 of the notes to Consolidated Financial Statements.

CAPITAL RESOURCES AND LIQUIDITY

The company's California Utility operations are the major source of liquidity. Funding of other business units' capital expenditures is significantly dependent on the California Utilities paying sufficient dividends to Sempra Energy and on SET's liquidity requirements, which fluctuate significantly.

At December 31, 2003, the company had $432 million in cash and $2.1 billion in available unused, committed lines of credit.

Management believes these amounts and cash flows from operations and new security issuances will be adequate to finance capital expenditure requirements (see Future Construction Expenditures and Investments for forecasted capital expenditures for the next five years), shareholder dividends, any new business acquisitions or start-ups, and other commitments. If cash flows from operations were to be significantly reduced 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. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings.

At the California Utilities, cash flows from operations and from new and refunding debt issuances are expected to continue to be adequate to meet utility capital expenditure requirements and provide dividends to Sempra Energy. However, if SDG&E receives CPUC approval of its plans to purchase from SER a 550-megawatt (MW) generating facility to be constructed in Escondido, California, the level of SDG&E's dividends to Sempra Energy is expected to be significantly lower during the construction of the facility to enable SDG&E to increase its equity in preparation for the purchase of the completed facility. See Note 15 of the notes to Consolidated Financial Statements for additional discussion on the planned Palomar plant.

SET provides or requires cash as the level of its net trading assets fluctuates with prices, volumes, margin requirements (which are substantially affected by credit ratings and commodity price fluctuations) and the length of its various trading positions. Its status as a source or use of cash also varies with its level of borrowing from its own sources. SET's intercompany borrowings were $359 million at December 31, 2003, down from $418 million at December 31, 2002. SET's external debt was $115 million at December 31, 2002. There was no external debt outstanding at December 31, 2003. Company management continuously monitors the level of SET's cash requirements in light of the company's overall liquidity. Such monitoring includes the procedures discussed in "Market Risk."

SELNG will require funding for its planned development of LNG receiving facilities. While funding from the company is expected to be adequate for these requirements, the company may decide to use project financing if that is believed to be advantageous.

SER's projects are expected to be financed through a combination of project financing, SER's borrowings and funds from the company.

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 development of pipelines to serve LNG facilities expected to be developed in Baja California, Mexico and Hackberry, Louisiana.

In the longer term, SEF is expected to again be a net provider of cash through reductions of consolidated income tax payments resulting from its investments in affordable housing and synthetic fuel. However, that was not true in 2003 and will not be true in the near term, while the company is in an alternative minimum tax position.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $1.1 billion, $1.4 billion and $0.7 billion for 2003, 2002 and 2001, respectively.

The decrease in cash flows from operations in 2003 compared to 2002 was primarily attributable to a decrease in overcollected regulatory balancing accounts at the California Utilities, partially offset by higher accounts payable in 2003 primarily due to timing.

The increase in cash flows from operations in 2002 compared to 2001 was attributable to SDG&E's collection of balancing accounts (see Note 1 of the notes to Consolidated Financial Statements) and the change to a net income tax liability position at December 31, 2002 compared to a net income tax asset position at the end of 2001. In addition, cash flows from operations increased due to less growth in net trading assets and the payment of higher trade payables in 2001. These increases were partially offset by a decrease in deferred income taxes and investment tax credits and higher accounts receivable in 2002 resulting from an increase in SoCalGas' natural gas commodity costs for the fourth quarter of 2002 compared to the corresponding period in the prior year.

During 2003, the company made pension plan contributions of $27 million for the 2003 plan year. Contributions of $3 million were made in each of 2002 and 2001.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $1.3 billion, $1.7 billion and $1.0 billion for 2003, 2002 and 2001, respectively.

The decrease in cash used in investing activities in 2003 compared to 2002 was primarily due to lower capital expenditures for the Termoeléctrica de Mexicali (TDM) power plant and lower investments in U.S. Treasury obligations made in connection with the Mesquite synthetic lease, higher distributions from investments in South America, and SET's higher acquisition activities in 2002.

The increase in cash used in investing activities in 2002 compared to 2001 was primarily due to increased capital expenditures, primarily at SER and the California Utilities, and SET's acquisition activities.

Expenditures for property, plant and equipment, and for those investments that effectively constitute similar expenditures, are presented in the following table.

(Dollars in millions)	
2003	**$1,228**
2002	$1,524
2001	$1,179
2000	$ 963
1999	$ 705

The 2002 amount is larger than the other years due to the construction of the SER power plants.

Capital Expenditures for Property, Plant and Equipment

Capital expenditures were $1.0 billion in 2003 compared with $1.2 billion in 2002 and $1.1 billion in 2001. The decrease in 2003 from 2002 was due primarily to lower capital expenditures for the TDM power plant.

The California Utilities

Capital expenditures for property, plant, and equipment by the California Utilities were $762 million in 2003 compared to $731 million in 2002 and $601 million in 2001. The increase in 2003 was primarily due to $40 million of capital costs associated with the Southern California wildfires in October 2003. The increase in 2002 was due to additions to SDG&E's natural gas and electric distribution systems, improvements to SoCalGas' distribution system, and expansion of pipeline capacity to meet increased demand by electric generators and by commercial and industrial customers.

Sempra Energy Resources

SER acquires, develops and operates power plants throughout the U.S. and Mexico. The following table lists the MW capacity of each power plant currently in operation. All of the plants are natural gas-fired combined-cycle facilities, except for Twin Oaks Power, which is coal-fired.

Power Plant	Generating Capacity	Location
Mesquite Power	1,250	Arlington, AZ
Termoeléctrica De Mexicali	600	Mexicali, Mexico
Twin Oaks Power	305	Bremond, TX
Elk Hills Power (50% owned)	275*	Bakersfield, CA
El Dorado (50% owned)	240*	Boulder City, NV
Total MW in operation	2,670	

* SER's share

Other potential plants, including the Palomar plant, which is discussed above and in Note 15 of the notes to Consolidated Financial Statements, are in various stages of consideration, permitting or site-acquisition. Others have completed these stages but construction is awaiting market changes that will permit advance signing of long-term contracts at adequate margins.

In 2003, TDM commenced operations of its 600-MW, $350 million power plant near Mexicali, Baja California, Mexico. SER invested $34 million and $158 million in TDM in 2003 and 2002, respectively.

Operations also commenced in 2003 for the wholly owned 1,250-MW Mesquite Power plant, located near Phoenix, Arizona. Prior to 2004, this project was financed through a synthetic lease agreement. See further discussion of the consolidation of Mesquite Trust, the owner of Mesquite Power, in Note 1 of the notes to Consolidated Financial Statements. In January 2004, the company terminated the lease and purchased the assets of Mesquite Trust for $631 million.

Also in 2003, SER made turbine payments of $69 million for power plants under development.

In October 2002, SER purchased the 305-MW, coal-fired Twin Oaks power plant for $120 million.

See Note 2 of the notes to Consolidated Financial Statements for additional discussion on SER's recent power plant investments and acquisitions.

Sempra Energy LNG

In April 2003, SELNG completed its previously announced acquisition of the proposed Cameron LNG project from a subsidiary of Dynegy, Inc. In December 2003, SELNG and Shell International Gas Limited announced plans to form a 50/50 joint venture to build, own and operate Energía Costa Azul, an LNG receiving terminal in Baja California. In December 2003, SELNG signed a Heads of Agreement (HOA) for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energía Costa Azul. The non-binding HOA is expected to be the precursor to a full 20-year purchase/supply agreement. In 2003, SELNG invested $42 million in Cameron LNG and $10 million in Energía Costa Azul. See Note 2 of the notes to Consolidated Financial Statements for additional discussion on the LNG projects.

Sempra Energy International

In 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a pipeline built by PG&E Corporation that connects to

Arizona. SEI invested $17 million, $37 million and $74 million in the pipeline in 2003, 2002 and 2001, respectively, for a total through December 31, 2003 of $128 million.

Three of SEI's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. On February 7, 2003, SEI purchased the remaining minority interests in all of its Mexican subsidiaries. As a result, as of December 31, 2003, SEI owns 100 percent of all its Mexican subsidiaries. Through December 31, 2003, the distribution companies have made capital expenditures aggregating $127 million. Total capital expenditures for these subsidiaries were $15 million in both 2003 and 2002, and $19 million in 2001.

Sempra Energy Trading

In 2003, SET spent $27 million for the development of Bluewater Gas Storage, LLC. See Note 2 of the notes to Consolidated Financial Statements for further discussion.

Investments

Investments and acquisition costs were $202 million, $429 million and $111 million for 2003, 2002 and 2001, respectively. The decrease from 2003 to 2002 was due to lower investments in U.S. Treasury obligations made in connection with the Mesquite synthetic lease in 2003 and SET's higher acquisition activities in 2002. The increase in 2002 was due to the increase in requirements for the synthetic lease financing for the construction of the Mesquite Power plant and SET's acquisition of new businesses. For a discussion of the synthetic lease, see Note 2 of the notes to Consolidated Financial Statements.

Sempra Energy Trading

During 2002, SET completed acquisitions that added base metals trading and warehousing to its trading business. The purchase price of the 2002 acquisitions totaled $119 million, net of cash acquired. For additional discussion related to the SET acquisitions, see Note 2 of the notes to Consolidated Financial Statements.

Sempra Energy Resources

In July 2003, the 550-MW Elk Hills power plant near Bakersfield, California began commercial operations. Elk Hills, an unconsolidated subsidiary, is jointly owned with Occidental Energy Ventures Corporation (Occidental) and supplies electricity to California. During 2003, 2002 and 2001, SER invested $47 million, $39 million and $91 million, respectively. Information concerning litigation with Occidental is provided in Note 15 of the notes to Consolidated Financial Statements.

Other

See further discussion of investing activities, including the $197 million foreign currency exchange adjustment relating to Argentina, in Notes 2 and 3 of the notes to Consolidated Financial Statements.

Future Construction Expenditures and Investments

The company expects to make capital expenditures of $1.1 billion in 2004. Significant capital expenditures are expected to include $750 million for California utility plant improvements and $170 million for the development of the two LNG regasification terminals. These expenditures are expected to be financed by cash flows from operations and security issuances.

Over the next five years, the company expects to make capital expenditures of $4.4 billion at the California Utilities and has identified $2.1 billion of capital expenditures at the other subsidiaries, including the development of the LNG facilities and construction of power plants by SER. Both amounts include the Palomar plant (see Note 15 of the notes to Consolidated Financial Statements for further discussion) which would be constructed by SER and then purchased by SDG&E.

Construction, investment and financing programs are periodically 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. In addition, the excess of existing power plants and other energy-related facilities compared to market demand in certain regions of the country and/or the plants that are owned by companies in financial distress may provide the company with opportunities to acquire existing power plants instead of or in addition to new construction.

The company's level of construction expenditures and 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. The company intends to finance its capital expenditures in a manner that will maintain its strong investment-grade ratings and capital structure.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash provided by financing activities totaled $109 million, $138 million and $275 million for 2003, 2002 and 2001, respectively.

The cash provided by financing activities decreased in 2003 due to reduced long-term borrowings and higher repayments on long-term debt and short-term borrowings, partially offset by an increase in stock issuances.

Cash flows from financing activities decreased in 2002 from 2001 due primarily to the higher temporary drawdowns of lines of credit in 2001, partially offset by increased debt issuances in 2002.

Long-Term and Short-Term Debt

In 2003, the company issued $900 million in long-term debt, consisting of $400 million of senior unsecured notes and $500 million of first mortgage bonds issued by SoCalGas.

Repayments on long-term debt in 2003 included $100 million of the borrowings under a line of credit and $66 million of rate-reduction bonds. In 2003, SEF repaid $36 million of debt incurred to acquire limited partnership interests. Repayments also included $325 million of SoCalGas' first mortgage bonds. In addition, $70 million of SoCalGas' $75 million medium-term notes were put back to the company. The remaining $5 million matures in 2028.

In January 2004, SoCalGas optionally redeemed its $175 million 6.875% first mortgage bonds. Also in January 2004, SER purchased the assets of Mesquite Trust, thereby extinguishing $630 million of debt outstanding.

The net short-term debt reduction of $518 million in 2003 primarily consisted of the paydown of commercial paper.

In 2002, the company issued $1.2 billion in long-term debt, including $600 million of equity units at Sempra Energy and $250 million of 4.80% first mortgage bonds at SoCalGas. Each equity unit consists of $25 principal amount of the company's 5.60% senior notes due May 17, 2007 and a contract to purchase for $25 on May 17, 2005, between .8190 and .9992 of a share of the company's common stock, with the precise number within that range to be determined by the then-prevailing market price. In addition, SER drew down $300 million against a line of credit to finance construction projects and acquisitions.

Repayments on long-term debt in 2002 of $479 million included $200 million borrowed under a line of credit, $138 million of first mortgage bonds and $66 million of rate-reduction bonds.

The net short-term debt reduction of $307 million in 2002 primarily consisted of the paydown of commercial paper.

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.

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 California, Arizona and Mexico.

In August 2003 Global replaced a $950 million revolving line of credit with two syndicated revolving credit agreements, permitting aggregate revolving credit borrowings of $1 billion. Global had no commercial paper outstanding at December 31, 2003 and $422 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2002.

See Notes 1, 4 and 5 of the notes to Consolidated Financial Statements for further discussion of debt activity and lines of credit.

Capital Stock Transactions

On October 14, 2003, the company completed a common stock offering of 16.5 million shares priced at $28 per common share, resulting in net proceeds of $448 million. The proceeds were used primarily to pay off short-term debt.

In April and May of 2002, the company publicly offered and sold $600 million of "Equity Units," as discussed above.

Dividends

Dividends paid on common stock amounted to $207 million in 2003, $205 million in 2002 and $203 million in 2001.

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 the amounts that are available for loans and dividends to the company from the California Utilities. At December 31, 2003, SDG&E and SoCalGas could have provided a total (combined loans and dividends) of $290 million and $175 million, respectively, to Sempra Energy. At December 31, 2003, SDG&E and SoCalGas had actual loans, net of payables, to Sempra Energy of $75 million and $21 million, respectively.

Capitalization

Total capitalization, including the current portion of long-term debt and excluding the rate-reduction bonds (which are non-recourse to the company) at December 31, 2003 was $9.1 billion. The debt-to-capitalization ratio was 55 percent at December 31, 2003. Significant changes in capitalization during 2003 included the October 2003 common stock offering, long-term borrowings and repayments, income and dividends.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2003. Trading liabilities are not included herein as such derivative transactions are primarily hedged against trading assets. In addition, liabilities reflecting fixed-price contracts and other derivatives are excluded as they are primarily offset against regulatory assets at the California Utilities. Additional information concerning commitments is provided above and in Notes 4, 5, 11 and 15 of the notes to Consolidated Financial Statements.

(Dollars in millions)	2004	2005 and 2006	2007 and 2008	Thereafter	Total
Short-term debt	$ 28	$ —	$ —	$ —	$ 28
Long-term debt	1,433	499	690	2,652	5,274
Due to unconsolidated affiliates	—	—	62	300	362
Preferred stock of subsidiaries subject to mandatory redemption	1	3	20	—	24
Operating leases	97	162	145	213	617
Purchased-power contracts	214	457	458	2,235	3,364
Natural gas contracts	988	358	46	207	1,599
Construction commitments	19	16	14	48	97
Twin Oaks coal supply	29	54	50	322	455
SONGS decommissioning	20	22	9	265	316
Asset retirement obligations	4	8	2	7	21
Environmental commitments	23	38	—	—	61
Other	—	—	20	55	75
Totals	$2,856	$1,617	$1,516	$6,304	$12,293

Credit Ratings

Several credit ratings of the company and its subsidiaries declined in 2003, but remain investment grade. As of January 31, 2004, credit ratings for Sempra Energy and its primary subsidiaries were as follows:

	S&P*	Moody's**	Fitch
SEMPRA ENERGY			
Unsecured debt	BBB+	Baa1	A
Trust preferred securities	BBB-	Baa2	A-
SDG&E			
Secured debt	A+	A1	AA
Unsecured debt	A-	A2	AA-
Preferred stock	BBB+	Baa1	A+
Commercial paper	A-1	P-1	F1+
SOCALGAS			
Secured debt	A+	A1	AA
Unsecured debt	A-	A2	AA-
Preferred stock	BBB+	Baa1	A+
Commercial paper	A-1	P-1	F1+
PACIFIC ENTERPRISES			
Preferred stock	BBB+	—	A
GLOBAL			
Unsecured debt guaranteed by Sempra Energy	—	Baa1	—
Commercial paper guaranteed by Sempra Energy	A-2	P-2	F1

* Standard & Poor's
** Moody's Investor Services, Inc.

As of January 31, 2004, the company has a stable outlook rating from all three credit rating agencies.

FACTORS INFLUENCING FUTURE PERFORMANCE

The California Utilities provide a generally stable base of earnings for the company. Earnings growth and variability results primarily from activities at SET, SER, SELNG and SEI. Developments and pending matters concerning the factors influencing future performance are summarized below. Notes 13, 14 and 15 of the notes to Consolidated Financial Statements describe events in the deregulation of California's electric and natural gas industries and various FERC, SET and income tax issues.

California Utilities

Electric Industry Restructuring and Electric Rates

Subsequent to the electric capacity shortages of 2000-2001, SDG&E's service territory had and continues to have an adequate supply of electricity. However, various projections of electricity demand in SDG&E's service territory indicate that, without additional electrical generation and transmission and reductions in electrical usage, beginning in 2005, electricity demand could begin to outstrip available resources. SDG&E has issued a request for proposals (RFP) to meet the electric capacity shortfall, estimated at 69 MW in 2005 and increasing annually by approximately 100 MW, and has filed a proposed plan at the CPUC for meeting these capacity requirements. See Note 13 of the notes to Consolidated Financial Statements for additional information regarding the RFP results.

Through December 31, 2003, the operating and capital costs of SONGS Units 2 and 3 were recovered through the ICIP mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004 the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase would start over at January 1, 2004, essentially eliminating earnings from SONGS except from future increases in ratebase.

See additional discussion of this and related topics, including the CPUC's adjustment to its plan for deregulation of electricity, in Note 13 of the notes to Consolidated Financial Statements.

Natural Gas Restructuring and Rates

In December 2001 the CPUC issued a decision related to natural gas industry restructuring; however, implementation has been delayed. A CPUC decision could be issued in the first quarter of 2004. With the California Utilities' natural gas supply contracts nearing expiration, the company believes that regulation needs to consider sufficiently the adequacy and diversity of supplies to California, transportation infrastructure and cost recovery thereof, hedging opportunities to reduce cost volatility, and programs to encourage and reward conservation. Additional information on natural gas industry restructuring is provided in Note 14 of the notes to Consolidated Financial Statements.

CPUC Investigation of Compliance with Affiliate Rules

On February 27, 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to ensure that they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit will cover years 1997 through 2003, is expected to commence in March 2004 and should be completed by the end of 2004. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits. Additional information on the CPUC's investigation is provided in Note 14 of the notes to Consolidated Financial Statements.

Cost of Service Filing

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases designed to reflect forecasts of 2004 capital and operating costs. The California Utilities are requesting revenue increases of $121 million. On December 19, 2003, settlements were filed with the CPUC for SoCalGas and for SDG&E that, if approved, would resolve most of the cost of service issues. A CPUC decision is likely in the second quarter of 2004. The California Utilities have also filed for continuation through 2004 of existing PBR mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but deferred action on applying any rewards or penalties for performance relative to these targets to a decision to be issued later in 2004 in a second phase of these applications. This is discussed in Note 14 of the notes to Consolidated Financial Statements.

Sempra Energy Global Enterprises

Electric-Generation Assets

As discussed in "Cash Flows From Investing Activities," the company has been involved in the development of several electric-generation projects that will significantly impact the company's future performance. SER has 2,670 MW (its share) of new generation in operation, including the 550-megawatt Elk Hills power project, the 1,250-megawatt Mesquite Power plant, the 600-megawatt TDM power plant, the 305-megawatt Twin Oaks power plant and the 480-megawatt El Dorado Energy. Except for Elk Hills, the plants' electricity is available for markets in California, Arizona, Texas and Mexico and may be used to supply power to California under SER's agreement with the DWR.

Investments

As discussed in "Cash Flows From Investing Activities," the company's investments will significantly impact the company's future performance. During 2002, SET completed acquisitions that added base metals trading and warehousing to its trading business. These acquisitions included Sempra Metals Limited and Henry Bath & Son Limited. In addition, SET acquired assets of Sempra Metals & Concentrates Corp. and the U.S. warehousing business of Henry Bath, Inc., and SER acquired the Twin Oaks Power plant.

SELNG is in the process of developing Energía Costa Azul, an LNG receiving terminal in Baja California, Mexico, and the Cameron LNG receiving terminal in Hackberry, Louisiana. This is discussed in Note 2 of the notes to Consolidated Financial Statements. The viability and future profitability of this business unit is dependent upon numerous factors, including the relative prices of natural gas in North America and from LNG suppliers located elsewhere, negotiating sale and supply contracts at adequate margins, and completing cost-effective construction of the required facilities.

The Argentine economic decline and government responses (including Argentina's unilateral, retroactive abrogation of utility agreements early in 2002) are continuing to adversely affect the company's investment in two Argentine utilities. In September 2002, SEI initiated proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its Argentine investments resulting from governmental actions. SEI has made a request for arbitration to the International Center for Settlement of Investment Disputes. Additional information regarding this proceeding and related insurance is provided in Note 3 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 has adopted corporate-wide policies governing its market risk management and trading activities. Assisted by the company's Energy Risk Management Group (ERMG), the company's Energy Risk Management Oversight Committee (ERMOC), 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. Utility management receives daily information on positions and the ERMG receives information detailing positions creating market and credit risk from all company affiliates (on a delayed basis as to the California Utilities). The ERMG independently measures and reports the market and credit risk associated with these positions. 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 intervals. VaR is calculated independently by the ERMG for all company affiliates. Historical volatilities and correlations between instruments and positions are used in the calculation.

Following is a summary of SET's trading VaR profile (using a one-day holding period) in millions of dollars:

	95%	99%
December 31, 2003	$2.6	$3.7
2003 average	$6.5	$9.2
December 31, 2002	$4.6	$6.5
2002 average	$6.2	$8.7

The California Utilities use energy and gas derivatives to manage natural gas and energy price risk associated with servicing their load requirements. The use of derivative financial instruments by the California Utilities is subject to certain limitations imposed by company policy and regulatory requirements.

See the revenue recognition discussion in Notes 1 and 10 and the additional market risk information regarding derivative instruments 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, 2003 includes a discussion of how these exposures are managed.

Commodity Price Risk

Market risk related to physical commodities is created by volatility 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 various affiliates are exposed, in varying degrees, to price risk primarily in the petroleum, metals, natural gas 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

SET derives a substantial portion of its revenue from its worldwide trading activities in natural gas, electricity, petroleum products, metals and other commodities. As a result, SET is exposed to price volatility in the related domestic and international 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.

Sempra Energy Solutions

SES derives a substantial portion of its revenue from delivering electric and natural gas supplies to its commercial and industrial customers. As a result, SES is exposed to price volatility in the related domestic markets. Its contracts are written in a manner intended 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.

California Utilities

With respect to the California Utilities, market risk exposure is limited due to CPUC authorized rate recovery of commodity purchase, sale, intrastate transportation and storage activity. However, the California Utilities may, at times, be exposed to market risk as a result of SDG&E's natural gas PBR and electric procurement activities or SoCalGas' GCIM, which are discussed in Notes 13 and 14 of the notes to Consolidated Financial Statements. They manage their risk within the parameters of the company's market risk management framework. As of December 31, 2003, the total VaR of the California Utilities' natural gas and electric positions was not material. In addition, if commodity prices rose too rapidly, it is likely that volumes would decline. This would increase the per-unit fixed costs, which could lead to further volume declines, leading to increased per-unit fixed costs and so forth.

Interest Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its long-term debt. The company historically has funded utility operations through long-term debt issues with fixed interest rates and these interest rates are recovered in utility rates. As a result, some recent debt offerings 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, 2003, the California Utilities had $1.8 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 on variable-rate debt is provided for in rates on a forecasted basis. At December 31, 2003, utility fixed-rate debt had a one-year VaR of $280 million and utility variable-rate debt had a one-year VaR of $11 million. Non-utility debt (fixed-rate and variable-rate) subject to VaR modeling totaled $2.6 billion at December 31, 2003, with a one-year VaR of $176 million.

At December 31, 2003, the notional amount of interest-rate swap transactions totaled $650 million. See Note 5 of the notes to Consolidated Financial Statements for further information regarding interest rate swap transactions.

In addition the company is ultimately subject to the effect of interest-rate fluctuation on the assets of its pension plan and other postretirement plans.

Credit Risk

Credit risk is the risk of loss that would be incurred as a result of nonperformance by counterparties of their contractual obligations. As with market risk, the company has adopted corporate-wide policies governing the management of credit risk. Credit risk management is performed by the ERMG and the California Utility's credit department and overseen by the ERMOC. Using rigorous models, the groups continuously calculate current and potential credit risk to counterparties to monitor actual balances in comparison to approved limits. The company avoids concentration of counterparties whenever possible and management believes its credit policies with regard to counterparties significantly reduce overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty and other security such as lock-box liens and downgrade triggers. At December 31, 2003, SET had 17 customers that owed $20 million to $100 million each. The majority of these accounts related to amounts invoiced for delivered physical energy commodities and were settled within 30 days. The company believes that adequate reserves have been provided for counterparty nonperformance.

As described in Note 15 of the notes to Consolidated Financial Statements, SER has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. This contract results in a significant potential nonperformance exposure with a single counterparty; however, this risk has been addressed and mitigated by the terms of the contract.

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 counterparties to the agreement not perform. See "Interest Rate Risk" for additional information regarding the company's use of interest-rate swap agreements.

Foreign Currency Rate Risk

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 that began at the end of 2001, SEI has reduced the carrying value of its investment downward by a cumulative total of $197 million as of December 31, 2003. These non-cash adjustments continue to occur based on fluctuations in the Argentine peso and have not affected net income, but have affected other comprehensive income (loss) and accumulated other comprehensive income (loss). See further discussion in Note 3 of the notes to Consolidated Financial Statements.

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, 2003, the company had no significant arrangements of this type.

CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS

Certain accounting policies are viewed by management as critical because their application is the most relevant, judgmental and/or material to the company's financial position and results of operations, and/or because they require the use of material judgments and estimates.

The company's most significant accounting policies are described in Note 1 of the notes to Consolidated Financial Statements. The most critical policies, all of which are mandatory under generally accepted accounting principles and the regulations of the Securities and Exchange Commission, are the following:

> *SFAS 5 "Accounting for Contingencies,"* establishes the amounts and timing of when the company provides for contingent losses. Details of the company's issues in this area are discussed in Note 15 of the notes to Consolidated Financial Statements.
>
> *SFAS 71* "*Accounting for the Effects of Certain Types of Regulation*," has a significant effect on the way the California Utilities record assets and liabilities, and the related revenues and expenses, that would not be recorded absent the principles contained in SFAS 71.
>
> *SFAS 109 "Accounting for Income Taxes,"* governs the way the company provide for income taxes. Details of the company's issues in this area are discussed in Note 7 of the notes to Consolidated Financial Statements.

SFAS 123 "Accounting for Stock-Based Compensation" and SFAS 148 "Accounting for Stock-Based Compensation—Transition and Disclosure," give companies the choice of recognizing a cost at the time of issuance of stock options or merely disclosing what that cost would have been and not recognizing it in its financial statements. The company, like most U.S. companies, has elected the disclosure option for all options that are so eligible. The effect of this is discussed in Note 1 of the notes to Consolidated Financial Statements.

SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" and SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," have a significant effect on the balance sheets of SET, SES and the California Utilities but have no significant effect on the California Utilities' income statements because of the principles contained in SFAS 71. The effect on SET's income statement is discussed in Note 10 of the notes to Consolidated Financial Statements.

EITF 02-3 "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," has a significant effect on the financial statements of SET and SES, both of which had been recording transactions in accordance with EITF Issue 98-10, which was eliminated by EITF Issue 02-3. However, most of the trading assets and liabilities of SET and SES will now be covered by SFAS 133, SFAS 138 and SFAS 149, which have a similar effect.

SFAS 52 "Foreign Currency Translation" is critical to the company's international operations and its application is materially affected by the company's treatment of certain loans to the Argentine affiliates as equity (based on expectations that repayment will not occur in the near future).

FIN 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51," is critical to the company's consolidation of variable interest entities (VIEs) in its financial statements. FIN 46 requires the company to consolidate VIEs for which it is the primary beneficiary, as defined, and deconsolidate any previously consolidated affiliates that do not meet the consolidation criteria of FIN 46. Sempra Energy has identified two VIEs for which FIN 46 deems it to be the primary beneficiary. One of the VIEs is the owner of the Mesquite Power plant. The other VIE relates to an investment in an unconsolidated subsidiary, AEG. Sempra Energy consolidated these entities in its financial statements at December 31, 2003. In accordance with FIN 46, the company deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. See further discussion in Note 1 of the notes to Consolidated Financial Statements.

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 or realizable values (including the likelihood of fully realizing the value of the investments in Argentina under the Bilateral Investment Treaty and the realizable value of Frontier Energy and AEG, all of which are discussed in Note 1 of the notes to Consolidated Financial Statements).

The collectibility of receivables, regulatory assets, deferred tax assets and other assets.

The costs to be incurred in fulfilling certain contracts that have been marked to market.

The various assumptions used in actuarial calculations for pension and other postretirement benefit plans.

The likelihood of recovery of various deferred tax assets.

The probable costs to be incurred in the resolution of litigation.

Differences between estimates and actual amounts have had significant impacts in the past and are likely to do so in the future.

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 and other techniques. The assumed collectibility of receivables considers the aging of the receivables, the creditworthiness of customers and the enforceability of contracts, where applicable. 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 the other parties and other factors. Costs to fulfill contracts that are carried at fair value are based on prior experience. Actuarial assumptions are based on the advice of the company's independent actuaries. The likelihood of deferred tax recovery is based on analyses of the deferred tax assets and the company's expectation of future financial and/or taxable income, based on its strategic planning.

Choices among alternative accounting policies that are material to the company's financial statements and information concerning significant estimates have been discussed with the audit committee of the board of directors.

Key non-cash performance indicators for the company's subsidiaries include numbers of customers, and quantities of natural gas and electricity sold for the California Utilities, and plant availability factors at SER's generating plants. SET does not use non-cash performance factors. Its key indicators are profit margins by product line and by geographic area. The California Utilities' information is provided in "Introduction" and "Results of Operations." For competitive reasons, SER does not disclose its plant availability factors, but considers them to be very good, except for the second unit at Mesquite, which just began generation in December 2003. The following tables provide the SET information.

	Years ended December 31,	
Trading Margin (Dollars in millions)	**2003**	2002
Geographical:		
North America	**$366**	$311
Europe/Asia	**172**	165
Total	**$538**	$476
Product Line:		
Gas	**$141**	$173
Power	**69**	89
Oil — Crude and Products	**128**	74
Metals	**96**	78
Other	**104**	62
Total	**$538**	$476

Other than its two small natural gas utilities in the eastern United States, SEI's only consolidated operations are in Mexico. The three local natural gas distribution utilities have increased their customer count to almost 100,000 and their sales volume to almost 50 million cubic feet per day in 2003. The two pipelines had sales volumes of almost 450 million cubic feet per day in 2003.

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had a significant effect on the company are SFAS 143, 144, 148, 149 and 150, FIN 45 and 46, and EITF 98-10 and 02-3. They are described in Note 1 of the notes to Consolidated Financial Statements. Pronouncements that could have a material effect on the company are described below.

EITF Issue 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": In accordance with the EITF's rescission of Issue 98-10, the company no longer recognizes energy-related contracts under mark-to-market accounting unless the contracts meet the requirements stated under SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* and its successors, which is the case for a substantial majority of the company's contracts. Upon adoption of this consensus on January 1, 2003, the company recorded the initial effect of rescinding Issue 98-10 as a cumulative effect of a change in accounting principle, which reduced after-tax earnings by $29 million. This is further described in Note 1 of the notes to Consolidated Financial Statements.

SFAS 143, "Accounting for Asset Retirement Obligations": SFAS 143, requires entities to record the fair value of liabilities for legal obligations related to asset retirements in the period in which they are incurred. It also requires most energy utilities, including the California Utilities, to reclassify amounts recovered in rates for future removal costs not covered by a legal obligation from accumulated depreciation to a regulatory liability.

SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities": SFAS 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS 133. Under SFAS 149 natural gas forward contracts that are subject to unplanned netting (see Note 1 of the notes to Consolidated Financial Statements) do not qualify for the normal purchases and normal sales exception. The company has determined that all natural gas contracts are subject to unplanned netting and as such, these contracts will be marked to market. In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 will be further marked to market. Implementation of SFAS 149 on July 1, 2003 did not have a material impact on reported net income.

FIN 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51": In January 2003, the FASB issued FIN 46 to strengthen existing accounting guidance that addresses when a company should consolidate a VIE in its financial statements.

Sempra Energy has identified two VIEs for which it is the primary beneficiary. One of the VIEs (the Mesquite Trust) is the owner of the Mesquite Power plant for which the company has a synthetic lease agreement as described in Note 2. The other VIE relates to the investment in AEG. Sempra Energy consolidated these entities in its financial statements at December 31, 2003.

In accordance with FIN 46, the company has deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. See further discussion regarding FIN 46 in Note 1 of the notes to Consolidated 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," "could," "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 California Public Utilities Commission, the California Legislature, the California Department of Water Resources, environmental and other regulatory bodies in countries other than the United States, and the Federal Energy Regulatory Commission; 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; war and terrorist attacks; business, regulatory and legal decisions; the status 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 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)

	2003	2002	2001	2000	1999
OPERATING REVENUES					
California utilities:					
Gas	**$ 4,010**	$ 3,263	$ 4,371	$ 3,305	$ 2,911
Electric	**1,787**	1,282	1,676	2,184	1,818
Other	**2,090**	1,503	1,683	1,271	631
Total	**$ 7,887**	$ 6,048	$ 7,730	$ 6,760	$ 5,360
Operating income	**$ 939**	$ 987	$ 997	$ 884	$ 763
Net income	**$ 649**	$ 591	$ 518	$ 429	$ 394
Net income per common share:					
Basic	**$ 3.07**	$ 2.88	$ 2.54	$ 2.06	$ 1.66
Diluted	**$ 3.03**	$ 2.87	$ 2.52	$ 2.06	$ 1.66
Dividends declared per common share	**$ 1.00**	$ 1.00	$ 1.00	$ 1.00	$ 1.56
Return on common equity	**19.3%**	21.4%	19.5%	15.7%	13.4%
Effective income tax rate	**6.3%**	20.2%	29.1%	38.6%	31.2%
Price range of common shares	**$ 30.90-22.25**	$ 26.25-15.50	$ 28.61-17.31	$ 24.88-16.19	$ 26.00-17.13
AT DECEMBER 31					
Current assets	**$ 7,886**	$ 7,010	$ 4,790	$ 6,525	$ 3,090
Total assets	**$22,009**	$20,242	$17,476	$17,850	$13,312
Current liabilities	**$ 8,348**	$ 7,247	$ 5,472	$ 7,490	$ 3,236
Long-term debt (excludes current portion)	**$ 3,841**	$ 4,083	$ 3,436	$ 3,268	$ 2,902
Shareholders' equity	**$ 3,890**	$ 2,825	$ 2,692	$ 2,494	$ 2,986
Common shares outstanding (in millions)	**226.6**	204.9	204.5	201.9	237.4
Book value per common share	**$ 17.17**	$ 13.79	$ 13.16	$ 12.35	$ 12.58

Statement of Management's Responsibility for the 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 audit committee of 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 compliance with the system of internal control 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 high 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, comprised 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 the independent auditors, and recommends to the board of directors any appropriate response to those discussions. The audit committee appoints 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, 2003 and 2002, 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, 2003. 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, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003, and Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities an interpretation of ARB No. 51*, effective December 31, 2003.

Deloitte & Touche LLP

San Diego, California
February 23, 2004

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions, except per share amounts)	Years ended December 31, 2003	2002	2001
OPERATING REVENUES			
California utilities:			
Natural gas	**$ 4,010**	$ 3,263	$ 4,371
Electric	**1,787**	1,282	1,676
Other	**2,090**	1,503	1,683
Total	**7,887**	6,048	7,730
OPERATING EXPENSES			
California utilities:			
Cost of natural gas	**2,071**	1,381	2,549
Cost of electric fuel and purchased power	**541**	297	782
Other cost of sales	**1,204**	709	873
Other operating expenses	**2,287**	1,901	1,760
Depreciation and amortization	**615**	596	579
Franchise fees and other taxes	**230**	177	190
Total	**6,948**	5,061	6,733
Operating income	**939**	987	997
Other income — net	**26**	15	3
Interest income	**104**	42	83
Interest expense	**(308)**	(294)	(323)
Preferred dividends of subsidiaries	**(10)**	(11)	(11)
Trust preferred distributions by subsidiary	**(9)**	(18)	(18)
Income before income taxes	**742**	721	731
Income tax expense	**47**	146	213
Income before extraordinary item and cumulative effect of changes in accounting principles	**695**	575	518
Extraordinary item, net of tax (Note 1)	**—**	16	—
Income before cumulative effect of changes in accounting principles	**695**	591	518
Cumulative effect of changes in accounting principles, net of tax (Note 1)	**(46)**	—	—
Net income	**$ 649**	$ 591	$ 518
Weighted-average number of shares outstanding (thousands):			
Basic	**211,740**	205,003	203,593
Diluted	**214,482**	206,062	205,338
Income before extraordinary item and cumulative effect of changes in accounting principles per share of common stock			
Basic	**$ 3.29**	$ 2.80	$ 2.54
Diluted	**$ 3.24**	$ 2.79	$ 2.52
Income before cumulative effect of changes in accounting principles per share of common stock			
Basic	**$ 3.29**	$ 2.88	$ 2.54
Diluted	**$ 3.24**	$ 2.87	$ 2.52
Net income per share of common stock			
Basic	**$ 3.07**	$ 2.88	$ 2.54
Diluted	**$ 3.03**	$ 2.87	$ 2.52
Common dividends declared per share	**$ 1.00**	$ 1.00	$ 1.00

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, **2003**	2002
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 432**	$ 455
Short-term investments	**363**	—
Accounts receivable — trade	**1,012**	754
Accounts and notes receivable — other	**127**	132
Interest receivable	**62**	3
Due from unconsolidated affiliates	**—**	80
Income taxes receivable	**20**	—
Deferred income taxes	**—**	20
Trading assets	**5,250**	5,064
Regulatory assets arising from fixed-price contracts and other derivatives	**144**	151
Other regulatory assets	**89**	75
Inventories	**147**	134
Other	**240**	142
Total current assets	**7,886**	7,010
Investments and other assets:		
Due from unconsolidated affiliates	**55**	57
Regulatory assets arising from fixed-price contracts and other derivatives	**650**	812
Other regulatory assets	**554**	532
Nuclear decommissioning trusts	**570**	494
Investments	**1,114**	1,313
Fixed-price contracts and other derivatives	**—**	42
Sundry	**706**	664
Total investments and other assets	**3,649**	3,914
Property, plant and equipment:		
Property, plant and equipment	**15,317**	13,816
Less accumulated depreciation and amortization	**(4,843)**	(4,498)
Total property, plant and equipment — net	**10,474**	9,318
Total assets	**$22,009**	$20,242

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	**$ 28**	$ 570
Accounts payable — trade	**815**	694
Accounts payable — other	**64**	50
Income taxes payable	**—**	22
Deferred income taxes	**123**	—
Trading liabilities	**4,457**	4,094
Dividends and interest payable	**136**	133
Regulatory balancing accounts — net	**424**	578
Fixed-price contracts and other derivatives	**148**	153
Current portion of long-term debt	**1,433**	281
Other	**720**	672
Total current liabilities	**8,348**	7,247
Long-term debt	**3,841**	4,083
Deferred credits and other liabilities:		
Due to unconsolidated affiliates	**362**	162
Customer advances for construction	**89**	91
Postretirement benefits other than pensions	**131**	136
Deferred income taxes	**634**	800
Deferred investment tax credits	**84**	90
Regulatory liabilities arising from cost of removal obligations	**2,238**	2,486
Regulatory liabilities arising from asset retirement obligations	**281**	—
Other regulatory liabilities	**108**	121
Fixed-price contracts and other derivatives	**680**	813
Asset retirement obligations	**313**	—
Deferred credits and other	**831**	984
Total deferred credits and other liabilities	**5,751**	5,683
Preferred stock of subsidiaries	**179**	204
Mandatorily redeemable trust preferred securities	**—**	200
Commitments and contingent liabilities (Note 15)		
SHAREHOLDERS' EQUITY		
Preferred stock (50 million shares authorized, none issued)	**—**	—
Common stock (750 million shares authorized; 227 million and 205 million shares outstanding at December 31, 2003 and December 31, 2002, respectively)	**2,028**	1,436
Retained earnings	**2,298**	1,861
Deferred compensation relating to ESOP	**(35)**	(33)
Accumulated other comprehensive income (loss)	**(401)**	(439)
Total shareholders' equity	**3,890**	2,825
Total liabilities and shareholders' equity	**$22,009**	$20,242

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, **2003**	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 649**	$ 591	$ 518
Adjustments to reconcile net income to net cash provided by operating activities:			
Extraordinary item, net of tax	**—**	(16)	—
Cumulative effect of changes in accounting principles	**46**	—	—
Depreciation and amortization	**615**	596	579
Foreign currency loss (gain)	**8**	(63)	—
Deferred income taxes and investment tax credits	**(73)**	(92)	106
Non-cash rate reduction bond expense	**68**	82	66
Equity in (income) losses of unconsolidated affiliates	**(8)**	55	(12)
Impairment losses	**101**	—	—
Loss (gain) on sale and disposition of assets	**8**	14	(14)
Other — net	**2**	(5)	—
Net changes in other working capital components	**(224)**	151	(203)
Customer refunds paid	**—**	—	(127)
Changes in other assets	**(66)**	87	(280)
Changes in other liabilities	**(5)**	40	99
Net cash provided by operating activities	**1,121**	1,440	732
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	**(1,049)**	(1,214)	(1,068)
Investments and acquisitions of subsidiaries, net of cash acquired	**(202)**	(429)	(111)
Dividends received from unconsolidated affiliates	**72**	11	80
Net proceeds from sale of assets	**29**	—	128
Loans to unconsolidated affiliates	**(99)**	(82)	(57)
Other — net	**(4)**	(14)	(11)
Net cash used in investing activities	**(1,253)**	(1,728)	(1,039)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common dividends paid	**(207)**	(205)	(203)
Issuances of common stock	**549**	13	41
Repurchases of common stock	**(6)**	(16)	(1)
Issuances of long-term debt	**900**	1,150	675
Payments on long-term debt	**(601)**	(479)	(681)
Loan from unconsolidated affiliate	**—**	—	160
Increase (decrease) in short-term debt — net	**(518)**	(307)	310
Other — net	**(8)**	(18)	(26)
Net cash provided by financing activities	**109**	138	275
Decrease in cash and cash equivalents	**(23)**	(150)	(32)
Cash and cash equivalents, January 1	**455**	605	637
Cash and cash equivalents, December 31	**$ 432**	$ 455	$ 605

See notes to Consolidated Financial Statements.

	Years ended December 31,		
	2003	2002	2001
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, and debt due within one year)			
Accounts and notes receivable	**$(231)**	$ (121)	$ 353
Net trading assets	**81**	66	(362)
Income taxes — net	**6**	86	(121)
Inventories	**(13)**	(11)	33
Regulatory balancing accounts	**(156)**	170	88
Regulatory assets and liabilities	**(30)**	1	39
Other current assets	**(8)**	51	33
Accounts payable	**98**	(103)	(302)
Other current liabilities	**29**	12	36
Net changes in other working capital components	**$(224)**	$ 151	$(203)
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	**$ 296**	$ 279	$ 302
Income tax payments, net of refunds	**$ 118**	$ 140	$ 138
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Acquisition of subsidiaries:			
Assets acquired	**$ —**	$1,134	$ —
Cash paid, net of cash acquired	**—**	(119)	—
Liabilities assumed	**$ —**	$1,015	$ —
Consolidation of variable interest entities:			
Assets recorded	**$ 820**	$ —	$ —
Liabilities recorded	**(881)**	—	—
Total	**$ (61)**	$ —	$ —

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2003, 2002 and 2001

(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, 2000		$1,420	$1,162	$(39)	$ (49)	$2,494
Net income	$ 518		518			518
Comprehensive income adjustments:						
Foreign currency translation losses (Note 1)	(186)				(186)	(186)
Pension	(7)				(7)	(7)
Comprehensive income	$ 325					
Common stock dividends declared			(205)			(205)
Quasi-reorganization adjustment (Note 1)		35				35
Sale 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
Net income	$ 591		591			591
Comprehensive income adjustments:						
Foreign currency translation losses (Note 1)	(162)				(162)	(162)
Pension	(35)				(35)	(35)
Comprehensive income	$ 394					
Common stock dividends declared			(205)			(205)
Issuance of equity units (Note 5)		(61)				(61)
Sale of common stock		18				18
Repurchase of common stock		(16)				(16)
Common stock released from ESOP				3		3
Balance at December 31, 2002		1,436	1,861	(33)	(439)	2,825
Net income	**$ 649**		**649**			**649**
Comprehensive income adjustments:						
Foreign currency translation gains (Note 1)	**57**				**57**	**57**
Pension	**(16)**				**(16)**	**(16)**
SFAS 133	**(3)**				**(3)**	**(3)**
Comprehensive income	**$ 687**					
Common stock dividends declared			**(212)**			**(212)**
Equity units adjustment		**6**				**6**
Quasi-reorganization adjustment (Note 1)		**19**				**19**
Sale of common stock		**566**				**566**
Repurchase of common stock		**(6)**				**(6)**
Common stock released from ESOP		**7**		**(2)**		**5**
Balance at December 31, 2003		**$2,028**	**$2,298**	**$(35)**	**$(401)**	**$3,890**

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Sempra Energy (the company) and all majority-owned subsidiaries. Investments in affiliated companies over which Sempra Energy has the ability to exercise significant influence, but not control, are accounted for using the equity method. All material intercompany accounts and transactions have been eliminated.

Quasi-Reorganization

In 1993, Pacific Enterprises (PE) divested substantially all of its non-utility business and 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, were favorably resolved, resulting in restoring $35 million and $19 million to shareholders' equity in 2001 and 2003, respectively. These restorations did not affect the calculation of net income or comprehensive income. The remaining liabilities will be resolved in future years and 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 revenues and expenses during the reporting period, and the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual amounts can differ significantly from those estimates.

Basis of Presentation

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

Regulatory Matters

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).

The California Utilities prepare their financial statements in accordance with the provisions of *Statement of Financial Accounting Standards* (SFAS) *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 reductions in future rates for amounts due to customers. To the extent that 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 144,"Accounting for the Impairment or Disposal of Long-Lived Assets"* requires that a loss must be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase. Information concerning regulatory assets and liabilities is described in "Revenues," "Regulatory Balancing Accounts," and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2003, represent net payables (payables net of receivables) of $86 million and $338 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2002 were net payables of $184 million and $394 million. The payables normally are returned by reducing future rates.

Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. However, fluctuations in most operating and maintenance costs affect earnings. In addition, fluctuations in consumption levels affect earnings at SDG&E. The CPUC approved 100 percent balancing account treatment for variances between forecast and actual for SoCalGas' noncore revenues and throughput, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 13 and 14.

Regulatory Assets and Liabilities

In accordance with the accounting principles of SFAS 71, the company records regulatory assets and regulatory liabilities as discussed above.

Regulatory assets (liabilities) as of December 31 relate to the following matters:

(Dollars in millions)	**2003**	2002
SDG&E		
Fixed-price contracts and other derivatives	**$ 560**	$ 636
Recapture of temporary rate reduction*	**259**	326
Deferred taxes recoverable in rates	**273**	190
Unamortized loss on retirement of debt — net	**44**	49
Employee benefit costs	**35**	35
Cost of removal obligations**	**(846)**	(1,162)
Asset retirement obligations**	**(303)**	—
Other	**24**	7
Total	**46**	81
SoCalGas		
Fixed-price contracts and other derivatives	**233**	325
Environmental remediation	**44**	43
Unamortized loss on retirement of debt — net	**45**	38
Cost of removal obligation**	**(1,392)**	(1,324)
Deferred taxes refundable in rates	**(192)**	(164)
Employee benefit costs	**(77)**	(142)
Other	**8**	8
Total	**(1,331)**	(1,216)
PE — Employee benefit costs	**72**	80
Total PE consolidated	**(1,259)**	(1,136)
Total	**$(1,213)**	$(1,055)

* In connection with electric industry restructuring, which is described in Note 13, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.

** See discussion of SFAS 143 in "New Accounting Standards."

Net regulatory liabilities are recorded on the Consolidated Balance Sheets at December 31 as follows:

(Dollars in millions)	**2003**	2002
Current regulatory assets	**$ 233**	$ 226
Noncurrent regulatory assets	**1,204**	1,344
Current regulatory liabilities*	**(23)**	(18)
Noncurrent regulatory liabilities	**(2,627)**	(2,607)
Total	**$(1,213)**	$(1,055)

* Amount is included in Other Current Liabilities.

All of the assets either earn a return, generally at short-term rates, or the cash has not yet been expended and the assets are offset by liabilities that do not incur a carrying cost.

Cash and Cash Equivalents

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

Collection Allowances

The allowance for doubtful accounts was $19 million, $12 million and $22 million at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision for doubtful accounts of $5 million, $13 million and $21 million in 2003, 2002 and 2001, respectively.

The allowance for realization of trading assets was $67 million, $86 million and $23 million, at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision (reduction thereof) for trading assets of ($4) million, $20 million and $15 million in 2003, 2002 and 2001, respectively.

Trading Instruments

Trading assets and trading liabilities include option premiums paid and received; unrealized gains and losses from exchange-traded futures and options, over-the-counter (OTC) swaps, forwards, physical commodities and options; and base metals. Trading instruments are recorded by Sempra Energy Trading (SET) and Sempra Energy Solutions (SES) on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value. Unrealized gains and losses on OTC transactions reflect amounts which would be received from or paid to a third party upon net 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 netting arrangement. Additionally, as a result of SET's acquisitions in 2002, the company acquired $0.8 billion of base metals inventory. As of December 31, 2003 and 2002, trading assets included commodity inventory of $1.4 billion and $2.0 billion, respectively.

In October 2002, the Emerging Issues Task Force (EITF) rescinded fair value accounting for recording energy-trading activities and required contracts subsequently entered into to be accounted for at historical cost or the lower of cost or market, unless the contracts meet the requirements for fair value accounting under SFAS 133 and 149 (see below in "New Accounting Standards"). Energy transportation and storage contracts are recorded at cost. Energy commodity inventory is being recorded at the lower of cost or market. The company's base metals and concentrates inventory continue to be recorded at fair value in accordance with *Accounting Research Bulletin (ARB) No. 43 "Restatement and Revision of Accounting Research Bulletins."* See further discussion of EITF Issue 02-3 below in "New Accounting Standards."

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and carried at current market value based on current closing exchange quotations. Derivative commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and 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, current market values are derived using internally developed valuation methodologies based on available market information. When there is an absence of observable market data at inception, the value of the transaction is its cost. 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 reflected in net income. Although trading instruments may have scheduled maturities in excess of one year, the actual settlement of these transactions can occur sooner, resulting in the current classification of trading assets and liabilities on the Consolidated Balance Sheets. “New Accounting Standards” below provides a discussion of the rescission of EITF 98-10.

Inventories

At December 31, 2003, inventory shown on the Consolidated Balance Sheets, which does not include amounts included in trading assets, included natural gas of $89 million and materials and supplies of $58 million. The corresponding balances at December 31, 2002 were $77 million and $57 million, respectively. Natural gas at the California Utilities ($84 million and $74 million at December 31, 2003 and 2002, respectively) is valued by the last-in first-out (LIFO) method. When the California Utilities’ inventory is consumed, differences between the LIFO valuation and replacement cost are 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 services, and the newly constructed power plants at Sempra Energy Resources (SER).

The cost of plant includes labor, materials, contract services and related items. In addition, the cost of utility plant includes an allowance for funds used during construction (AFUDC). The cost of non-utility plant includes capitalized interest. The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

Property, plant and equipment balances by major functional categories are as follows:

	Property, Plant and Equipment at December 31,		Depreciation rates for years ended December 31,		
(Dollars in billions)	**2003**	2002	**2003**	2002	2001
California Utilities:					
Natural gas operations	**$ 8.0**	$ 7.7	**4.28%**	4.25%	4.25%
Electric distribution	**3.2**	3.0	**4.70%**	4.66%	4.67%
Electric transmission	**0.9**	0.9	**3.09%**	3.17%	3.19%
Other electric	**0.7**	0.6	**9.53%**	9.37%	8.46%
Total	**12.8**	12.2			
Other operations	**2.5**	1.6	**various**	various	various
Total	**$15.3**	$13.8			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $3.1 billion and $1.4 billion, respectively, at December 31, 2003, and were $2.9 billion and $1.3 billion, respectively, at December 31, 2002. See discussion of SFAS 143 under "New Accounting Standards." 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 13 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—Net, in the Statements of Consolidated Income, although it is not a current source of cash. AFUDC amounted to $29 million, $34 million and $17 million for 2003, 2002 and 2001, respectively. Total capitalized carrying costs, including AFUDC and the impact of SER's construction projects, were $55 million, $63 million and $28 million for 2003, 2002 and 2001, respectively.

Long-Lived Assets

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 are less than the carrying amount of the assets. If that comparison indicates that the assets' carrying value may be permanently impaired, the 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. See further discussion of SFAS 144 in "New Accounting Standards." During the third and fourth quarters of 2003, the company recorded impairment charges of $77 million and $24 million to write down the carrying value of the assets of Frontier Energy and Atlantic Electric & Gas Limited (AEG), respectively. This is discussed further in "New Accounting Standards" below.

Nuclear Decommissioning Liability

At December 31, 2002, in accordance with SFAS 71, SDG&E had recorded a $355 million regulatory liability representing SDG&E's share of the estimated future decommissioning costs of the San Onofre Nuclear Generating Station (SONGS). In addition, Deferred Credits and Other Liabilities included $139 million of accrued decommissioning costs associated with SONGS. As of December 31, 2003, as the result of implementing SFAS 143, "*Accounting for Asset Retirement Obligations,*" SDG&E had asset retirement obligations and related regulatory liabilities of $316 million and $303 million, respectively. Additional information on SONGS decommissioning costs is included below in "New Accounting Standards."

Legal Fees

Legal fees that are associated with a past event and not expected to be recovered in the future are accrued when it is probable that they will be incurred.

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, and certain hedging activities. The components of other comprehensive income are shown in the Statements of Consolidated Changes in Shareholders' Equity.

Stock-Based Compensation

The company has stock-based employee compensation plans, which are described in Note 9. The company accounts for these plans under the recognition and measurement principles of *Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees,"* and related Interpretations. For certain grants, no stock-based employee compensation cost is reflected in net income, since the options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. See "New Accounting Standards" below for further discussion. The following table provides the pro forma effects of recognizing compensation expense in accordance with *SFAS 123, "Accounting for Stock-Based Compensation":*

	Years ended December 31,		
	2003	2002	2001
Net income as reported	**$ 649**	$ 591	$ 518
Stock-based employee compensation expense included in the computation of net income, net of tax	**13**	3	7
Total stock-based employee compensation under fair value method for all awards, net of tax	**(20)**	(11)	(8)
Pro forma net income	**$ 642**	$ 583	$ 517
Earnings per share:			
Basic — as reported	**$3.07**	$2.88	$2.54
Basic — pro forma	**$3.03**	$2.84	$2.54
Diluted — as reported	**$3.03**	$2.87	$2.52
Diluted — pro forma	**$2.99**	$2.83	$2.52

Revenues

Revenues of the California Utilities are primarily derived from deliveries of electricity and natural gas to customers and changes in related regulatory balancing accounts. Revenues from electricity and natural gas sales and services are generally recorded under the accrual method and recognized upon delivery. The portion of SDG&E's electric commodity that was procured for its customers by the California Department of Water Resources (DWR) and delivered by SDG&E is not included in SDG&E's revenues or costs. For 2001, California Power Exchange (PX) and Independent System Operator (ISO) power revenues have been netted against purchased-power expense to avoid double-counting of power sold into and then repurchased from the PX/ISO. During 2003, costs associated with long-term contracts allocated to SDG&E from the DWR were also not included in the Statements of Consolidated Income, since the DWR retains legal and financial responsibility for these contracts. Refer to Note 13 for a discussion of the electric industry restructuring. 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 terms of up to three years. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

Through 2003, operating costs of SONGS Units 2 and 3, including nuclear fuel and related financing costs, and incremental capital expenditures were recovered through the Incremental Cost Incentive Pricing (ICIP) mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004 the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase would start over at January 1, 2004, essentially eliminating earnings from SONGS except from future increases in ratebase.

Additional information concerning utility revenue recognition is discussed above under "Regulatory Matters."

SET generates a substantial portion of its revenues from market making and trading activities, as a principal, in natural gas, electricity, petroleum, metals and other commodities, for which it quotes bid and ask 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 the fair value of unrealized gains and losses. SET also earns trading profits as a dealer by structuring and executing transactions. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and volatile fluctuations. These instruments include futures, forwards, swaps and options. 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 a 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 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. SET's financial instruments represent contracts with counterparties whereby payments are linked to or derived from market indices or on terms predetermined by the contract.

Non-derivative contracts are being carried at cost and accounted for on an accrual basis. Hence, the related profit or loss will be recognized as the contract is performed. Derivative instruments are discussed further in Note 10.

Revenues of SES are generated from commodity sales and energy-related products and services to commercial, industrial, government and institutional markets. Energy supply revenues from natural gas and electricity commodity sales are recognized on a current fair 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.

SET and SES record revenues from trading activities on a net basis in accordance with EITF 02-3. See further discussion of this matter and the rescission of EITF 98-10 under "New Accounting Standards."

Revenues of SER are derived primarily from the sale of electric energy to governmental and wholesale power marketing entities, which are recognized in accordance with provisions of *EITF 91-6*, *"Revenue Recognition of Long-term Power Supply Contracts,"* and *EITF 96-17*, *"Revenue Recognition Under Long-term Power Sales Contacts that Contain Both Fixed and Variable Terms."* During 2003 and 2002, electric energy sales to the DWR accounted for a significant portion of total SER revenues.

The consolidated foreign subsidiaries of Sempra Energy International (SEI), all of which operate in Mexico, recognize revenue similarly to the California Utilities, except that SFAS 71 is not applicable due to the different regulatory environment.

Extraordinary Gain

During 2002, SET acquired two businesses for amounts less than the fair values of the business' net assets. In accordance with *SFAS 141,* "*Business Combinations*," those differences were recorded as extraordinary income. The $16 million of extraordinary income was recorded in the second quarter ($2 million) and in the fourth quarter ($14 million).

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 comprehensive income and accumulated other comprehensive income, a component of shareholders' equity, as described below. Foreign currency transaction gains and losses are included in consolidated net income. To reflect the fluctuation in the Argentine peso, the functional currency of the company's Argentine operations, SEI adjusted its investment in its two Argentine natural gas utility holding companies upward by $26 million and downward by $102 million in 2003 and 2002, respectively. These non-cash adjustments did not affect net income, but did increase or reduce comprehensive income and accumulated other comprehensive income (loss). Smaller adjustments have been made to operations in other countries. Additional information concerning these investments is described in Note 3.

Transactions with Affiliates

Loans to 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 (8.168% at December 31, 2003) and are due on March 13, 2004. The total balance outstanding under the notes was $55 million and $56 million at December 31, 2003 and 2002, respectively. At December 31, 2003, this amount is included in non-current assets, under the caption Due from Unconsolidated Affiliates because they will be refinanced on longer terms.

Additionally, at December 31, 2002, SET had $79 million due from AEG and the company had $1 million due from other affiliates. At December 31, 2002, the outstanding loans are included in current assets under the caption Due from Unconsolidated Affiliates. In addition, SET had $44 million of trading assets due from AEG at December 31, 2002. At December 31, 2003, as a result of the adoption of FASB Interpretation No. (FIN) 46, AEG was consolidated. See "New Accounting Standards" below for a discussion of FIN 46.

Loans from Unconsolidated Affiliates

At both December 31, 2003 and 2002, SEI had long-term notes payable to affiliates which include $60 million at 6.47% due April 1, 2008 and $100 million at 6.62% due April 1, 2011. The loans are due to Chilquinta Energía Finance, LLC and are secured by SEI's investments in Chilquinta Energía S.A. and Luz del Sur S.A.A. (Luz del Sur) (See Note 3).

The company also reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates as a result of the adoption of FIN 46 effective December 31, 2003. In addition, dividend payments required on these instruments, previously recorded to Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded to Interest Expense for the last six months of 2003 on the company's Statements of Consolidated Income, in accordance with SFAS 150. See discussion of SFAS 150 in "New Accounting Standards" below.

Revenues and Expenses with Unconsolidated Affiliates

During 2003 and 2002 SER recorded $61 million and $39 million, respectively, in sales to El Dorado, an unconsolidated affiliate, and recorded $69 million and $49 million, respectively, of purchases for those same years.

New Accounting Standards

SFAS 132 (revised 2003), "Employers Disclosures about Pensions and Other Postretirement Benefits": This statement revised employers' disclosures about pension plans and other postretirement benefit plans. It requires disclosures beyond those in the original SFAS 132 about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement plans. It does not change the measurement or recognition of those plans. This statement is effective for financial statements with fiscal years ending after December 15, 2003.

SFAS 142, "Goodwill and Other Intangible Assets": In July 2001, the FASB issued SFAS 142, which provides guidance on how to account for goodwill and other intangible assets after an acquisition is complete. 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 in 2001. In accordance with the transitional guidance of SFAS 142, recorded goodwill attributable to the company was tested for impairment in 2002 by comparing the fair value to its carrying value, using a discounted cash flow methodology. As a result, during the first quarter of 2002, SEI recorded a pre-tax charge of $6 million related to the impairment of goodwill associated with its two domestic subsidiaries. Impairment losses are reflected in Other Operating Expenses in the Statements of Consolidated Income.

If goodwill amortization had not been recorded in 2001, reported net income for 2001 would have increased by $15 million to $533 million. Basic and diluted earnings per share would have increased by $0.07 to $2.61 and $2.59 respectively.

During 2002, SET completed several acquisitions as further discussed in Note 2. As a result of SET's acquisition of the metals warehousing business, the company recorded $21 million of goodwill on the Consolidated Balance Sheets. In addition, a $16 million after-tax extraordinary gain reflecting negative goodwill was recorded in 2002 for the purchase of the base metals and concentrates businesses.

During the first quarter of 2003 SEI purchased the remaining minority interests in its Mexican subsidiaries, which resulted in the recording of an addition to goodwill of $6 million and to an intangible asset of $4 million.

The changes in the carrying amount of goodwill (included in Noncurrent Sundry Assets on the Consolidated Balance Sheets) for the years ended December 31, 2003 and 2002 are as follows:

(Dollars in millions)	SET	Other	Total
Balance as of January 1, 2002	$120	$52	$172
Goodwill acquired during the year	21	—	21
Impairment losses	—	(6)	(6)
Other	—	(5)	(5)
Balance as of December 31, 2002	141	41	182
Goodwill acquired during the year	**—**	**6**	**6**
Balance as of December 31, 2003	**$141**	**$47**	**$188**

SET is the only reportable segment that has goodwill. In addition, the unamortized goodwill related to unconsolidated subsidiaries (included in Investments on the Consolidated Balance Sheets), primarily those located in South America, was $299 million and $294 million at December 31, 2003 and 2002, respectively, before foreign currency translation adjustments. Including foreign currency translation adjustments, these amounts were $232 million and $219 million, respectively. Unamortized other intangible assets were not material at December 31, 2003 and 2002.

SFAS 143, "Accounting for Asset Retirement Obligations": SFAS 143, issued in July 2001, addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of long-lived assets, 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 by the present value of the future retirement cost. Over time, the liability is accreted to its full value and paid, and the capitalized cost is depreciated over the useful life of the related asset.

The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. In addition, the company recorded a corresponding retirement obligation liability of $309 million (which includes accretion of that discounted value to December 31, 2002) and a regulatory liability of $215 million to reflect that SDG&E has collected the funds from its customers more quickly than SFAS 143 would accrete the retirement liability and depreciate the asset. These liabilities, less the $494 million already recorded (which represents amounts collected for future decommissioning costs), comprise the offsetting $30 million. See further discussion of SONGS' decommissioning and the related nuclear decommissioning trusts in Note 6.

On January 1, 2003, the company recorded additional asset retirement obligations of $20 million associated with the future retirement of a former power plant and three storage facilities.

In accordance with SFAS 143, Sempra Energy identified several other assets for which retirement obligations exist, but whose lives are indeterminate. A liability for these asset retirement obligations will be recorded if and when a life is determinable.

The change in the asset retirement obligations for the year ended December 31, 2003 is as follows (dollars in millions):

Balance as of January 1, 2003	$ —
Adoption of SFAS 143	329
Accretion expense	22
Payments	(14)
Balance as of December 31, 2003	$337*

* The current portion of the obligation is included in Other Current Liabilities on the Consolidated Balance Sheets.

Had SFAS 143 been in effect on January 1, 2002, the asset retirement obligation liability would have been $363 million as of that date.

Except for the items noted above, the company has determined that there is no other material retirement obligation associated with tangible long-lived assets.

Implementation of SFAS 143 has had no effect on results of operations and is not expected to have a significant effect in the future.

In accordance with CPUC regulations, the California Utilities collect estimated removal costs in rates through depreciation. SFAS 143 also requires the company to reclassify estimated removal costs, which have historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2003, these costs were $1.4 billion and $846 million for SoCalGas and SDG&E, respectively. At December 31, 2002, the corresponding amounts were $1.3 billion and $1.2 billion for SoCalGas and SDG&E, respectively. The decrease in the SDG&E amount during 2003 is due to SFAS 143 requiring further reclassification of those costs related to a legal obligation (primarily SONGS costs) to Asset Retirement Obligations.

SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets": In August 2001, the FASB issued SFAS 144, which replaces SFAS 121, *"Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of."* It applies to all long-lived assets. Among other things SFAS 144 requires that an impairment loss be recorded if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows.

During the third and fourth quarters of 2003, the company recorded impairment charges of $77 million and $24 million to write down the carrying value of the assets of Frontier Energy and AEG, respectively. The Frontier Energy impairment resulted from reductions in actual and anticipated sales of natural gas by the utility. The AEG impairment was due to less than anticipated customer growth. These charges are included in Other Operating Expenses in the Statements of Consolidated Income. In applying the provisions of SFAS 144, management determined the fair value of such assets based on its estimates of discounted future cash flows.

SFAS 148, "Accounting for Stock-Based Compensation—Transition and Disclosure": In December 2002, the FASB issued SFAS 148, an amendment to SFAS 123, *"Accounting for Stock-Based Compensation,"* which gives companies electing to expense employee stock options three methods to do so. In addition, the statement amends the disclosure requirements to require more prominent disclosure about the method of accounting for stock-based employee compensation and the effect of the method used on reported results in both annual and interim financial statements.

The company has elected to continue using the intrinsic value method of accounting for stock-based compensation. Therefore, SFAS 148 will not have any effect on the company's financial statements. See Note 9 for additional information regarding stock-based compensation.

SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities": Effective July 1, 2003, SFAS 149 amended and clarified accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS 133. Under SFAS 149 natural gas forward contracts that are subject to unplanned netting generally do not qualify for the normal purchases and normal sales exception. ("Unplanned netting" refers to situations whereby contracts are settled by paying or receiving money for the difference between the contract price and the market price at the date on which physical delivery would have occurred.) In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 will continue to be marked to market. Implementation of SFAS 149 did not have a material impact on reported net income.

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity": This statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that certain mandatorily redeemable financial instruments previously classified in the mezzanine section of the balance sheet be reclassified as liabilities. The company adopted SFAS 150 beginning July 1, 2003 by reclassifying $200 million of mandatorily redeemable trust preferred securities to Deferred Credits and Other Liabilities and $24 million of mandatorily redeemable preferred stock of subsidiaries to Deferred

Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets. In addition, dividend payments required on these instruments, previously recorded to Preferred Dividends of Subsidiaries and Trust Preferred Distributions, were recorded to Interest Expense on the company's Statements of Consolidated Income. For the year ended December 31, 2003, the related amount recorded as interest expense for the last six months totaled $9 million. On December 31, 2003, the $200 million of mandatorily redeemable trust preferred securities were reclassified to Due to Unconsolidated Affiliates due to the adoption of FIN 46 as discussed below.

EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities": In accordance with the EITF's rescission of Issue 98-10 by the release of Issue 02-3, the company no longer recognizes energy-related contracts under mark-to-market accounting unless the contracts meet the requirements stated under *SFAS 133 and SFAS 149,* which is the case for a substantial majority of the company's contracts. On January 1, 2003, the company recorded the initial effect of Issue 98-10's rescission as a cumulative effect of a change in accounting principle, which reduced after-tax earnings by $29 million. On a net basis, $9 million of the $29 million was realized during the year ended December 31, 2003. Neither the cumulative nor the ongoing effect impacts the company's cash flow or liquidity.

EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities": In June 2002, a consensus was reached in EITF 02-3, which codifies and reconciles existing guidance on the recognition and reporting of gains and losses on energy trading contracts, and addresses other aspects of the accounting for contracts involved in energy trading and risk management activities. Among other things, the consensus requires that mark-to-market gains and losses on energy trading contracts should be shown on a net basis in the income statement, effective for financial statements issued for periods ending after July 15, 2002. Adoption of EITF 02-3 in 2002 required that SES change its method of recording trading activities from gross to net, which had no impact on previously recorded gross margin, net income or cash provided by operating activities. SET was already recording revenues from trading activities on a net basis and required no change.

For 2001, recording revenues for all trading activities on a net basis decreased previously reported revenues by $348 million to $7.7 billion. There was no impact on reported revenues for the years ending December 31, 2003 and 2002 as trading activities were already reported on a net basis.

EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities and Not 'Held for Trading Purposes' as Defined in EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities": During 2003, the EITF reached a consensus that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Adoption of EITF 03-11 in 2003 did not have a significant impact to the company's financial statements and the company does not expect a significant impact in the future.

FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": In November 2002, the FASB issued FIN 45, which elaborates on the disclosures to be made in interim and annual financial statements of a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing a guarantee. As of December 31, 2003, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries. The only significant guarantees for which disclosure is required are that of the synthetic lease for the Mesquite Power plant, the mandatorily redeemable trust preferred securities and $25 million related to debt issued by Chilquinta Energía Finance, LLC, an unconsolidated affiliate. The synthetic lease for the Mesquite Power plant and the mandatorily redeemable trust preferred securities were also affected by FIN 46, as described below.

FIN 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51": FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the entity. During December 2003, the FASB issued FIN 46 revised (FIN 46R) to defer the implementation date for pre-existing variable interest entities (VIEs) that are special purpose entities (SPEs) until the end of the first interim or annual period ending after December 15, 2003. For VIEs that are not SPEs, companies must apply FIN 46R no later than the end of the first reporting period ending after March 15, 2004.

Sempra Energy has identified two VIEs for which it is the primary beneficiary. One of the VIEs (Mesquite Trust), which is an SPE, is the owner of the Mesquite Power plant for which the company had a synthetic lease agreement, as described in Notes 2 and 5. The Mesquite Power plant is a 1,250-megawatt (MW) project that provides electricity to wholesale energy markets in the Southwest. Construction began in September 2001 and the first phase of commercial operations (50 percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. Accordingly, as the FASB's deliberations during the deferral period did not result in the exclusion of Mesquite Trust from FIN 46's definitions, Sempra Energy consolidated this entity in its financial statements at December 31, 2003. The company bought out the lease in January 2004. At December 31, 2003, the total assets and total liabilities of Mesquite Trust were $643 million and $630 million, respectively. The company also recorded an after-tax credit for the cumulative effect from the change in accounting principle of $9 million.

The other variable interest entity is AEG, which markets power and natural gas commodities to commercial and residential customers in the United Kingdom. Sempra Energy consolidated AEG in its financial statements at December 31, 2003. Consolidation of AEG required Sempra Energy to record 100 percent of AEG's December 31, 2003 balance sheet, whereas it previously recorded only its share of AEG's net operating results. As of December 31, 2003 total assets and total liabilities of this unconsolidated subsidiary were $180 million and $251 million, respectively. Due to AEG's consolidation, the company recorded an after-tax charge for the cumulative effect of the change in accounting principle of $26 million.

In accordance with FIN 46R, the company deconsolidated a wholly owned subsidiary trust from its financial statements at December 31, 2003. The trust has no assets except for its corresponding receivable from the company. Due to the deconsolidation of this entity, Sempra Energy has reclassified $200 million of mandatorily redeemable trust preferred securities to Due to Unconsolidated Affiliates on its Consolidated Balance Sheets.

FASB Staff Position (FSP) 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003": Issued January 12, 2004, FSP 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The company has elected to defer the effects of the Act as provided by FSP 106-1. Any measure of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost in the financial statements or the accompanying notes do not reflect the impact of the Act on the plans. At this time, specific authoritative guidance on the accounting for the federal subsidy provided by the Act is pending and that guidance could require the company to change previously reported information.

Other Accounting Standards: During 2003 and 2002 the FASB and the EITF issued several statements that are not applicable to the company but could be in the future. In April 2002, the FASB issued SFAS 145, which rescinds *SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt,"* and *SFAS 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements."* In June 2002, the FASB issued *SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities."* SFAS 146 supersedes previous accounting guidance, principally *EITF 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)."*

NOTE 2. RECENT ACQUISITIONS AND INVESTMENTS

Sempra Energy Trading

In 2003, SET spent $27 million related to the development of Bluewater Gas Storage, LLC, a natural gas storage facility in Michigan. SET owns the rights to develop the facility and to utilize its capacity to store natural gas for customers who buy, sell or transport natural gas in Michigan. The facility is expected to commence operations in 2004.

During 2002, SET completed $119 million of acquisitions that added base metals trading and warehousing to its trading business. On February 4, 2002, SET completed the acquisition of London-based Sempra Metals Limited, a leading metals trader on the London Metals Exchange, for $65 million, net of cash acquired. In April 2002 SET completed the acquisition of the assets of New York-based Sempra Metals & Concentrates Corp., a leading global trader of copper, lead and zinc concentrates, for $24 million. Also in April 2002, SET completed the acquisition of Henry Bath & Sons Limited, which provides warehousing services for non-ferrous metals in Europe and Asia, and the assets of the U.S. warehousing business of Henry Bath, Inc., for a total of $30 million, net of cash acquired.

As discussed in Note 1, the company recognized an extraordinary after-tax gain of $16 million for negative goodwill for the acquisitions of the base metals and concentrates businesses. Additional information on the extraordinary gain is provided in Note 1. In addition, goodwill of $21 million related to the acquisition of the metals warehousing business was recorded on the Consolidated Balance Sheets and is expected to be fully deductible for tax purposes.

Sempra Energy Resources

In October 2002 SER purchased a 305-MW, coal-fired power plant (renamed Twin Oaks Power) for $120 million. SER sells substantially all of the output of the plant under a five-year contract expiring on October 1, 2007. In connection with the acquisition, SER also assumed a contract that includes annual commitments to purchase coal for the plant until an aggregate minimum volume has been achieved or through 2025.

Termoeléctrica De Mexicali (TDM), a 600-MW power plant near Mexicali, Baja California, Mexico, commenced operations in July 2003. In May 2003, a federal judge issued an order finding that the U.S. Department of Energy's (DOE) abbreviated assessment of two Mexicali power plants, including SER's TDM plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. On July 8, 2003, the judge ordered the DOE to conduct additional environmental studies, but denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE has until May 15, 2004, to demonstrate why the court should not set aside the permits. Through December 31, 2003, TDM has made capital expenditures of $342 million.

The 1,250-MW Mesquite Power plant, located near Phoenix, Arizona, cost $686 million and provides electricity to wholesale energy markets in the Southwest. The first phase of commercial operations (50 percent of the plant's total capacity) began in June 2003. The second phase of commercial operations (the remaining 50 percent) began in December 2003. As of December 31, 2003, this project was owned by the Mesquite Trust and financed through a synthetic lease agreement. Through December 31, 2003, SER had borrowed $630 million under this facility. All amounts above $280 million required collateralization through purchases of U.S. Treasury obligations. The collateralized U.S. Treasury obligations amounted to $363 million at December 31, 2003. This is included in Short-Term Investments on the Consolidated Balance Sheets. As a result of implementing FIN 46, Sempra Energy consolidated the Mesquite Trust, which had total assets and total liabilities of $643 million and $630 million, respectively, at December 31, 2003. See further discussion under "New Accounting Standards" in Note 1. On January 21, 2004, SER elected to purchase all of the power plant assets of Mesquite Trust for $631 million. The purchase required cash of $268 million and the liquidation of the $363 million in treasury securities held by the Mesquite Trust as collateral.

Sempra Energy LNG Corp.

In April 2003, Sempra Energy LNG Corp. (SELNG) completed its acquisition of the proposed Cameron liquefied natural gas (LNG) project in Hackberry, Louisiana from a subsidiary of Dynegy, Inc. SELNG has paid Dynegy $36 million for the acquisition, which includes rights to the location, licensing and FERC approval of the project, which is still in the permitting stage. Additional payments are contingent on meeting certain benchmarks and milestones and the performance of the project. As of December 31, 2003, the company had accrued $30 million as an estimate of the contingent payment. The total cost of the project is expected to be $700 million. The terminal will be capable of supplying 1.5 billion cubic feet (bcf) of natural gas per day. Construction is expected to begin in 2004 and commercial operations could begin in 2007. FERC approved the construction and operation of the project in September 2003.

In December 2003, SELNG and Shell International Gas Limited (Shell) announced plans to form a 50/50 joint venture to build, own and operate Energía Costa Azul, a LNG receiving terminal in Baja California on the west coast of Mexico, approximately 50 miles south of San Diego. The proposed joint venture will combine the two separate Baja California LNG receiving terminals proposed by Shell and SELNG into a single project. It is expected that construction will begin in 2004 with terminal operations commencing in 2007. The cost of the project is estimated to be $600 million. The terminal will be capable of supplying 1 billion cubic feet (bcf) of natural gas per day, half of which will be used to meet the growing energy demands in western Mexico. The proposed joint venture contemplates that SELNG and Shell would share the investment costs of the terminal equally and each would take 50 percent of the capacity of the terminal. Any surplus natural gas from the facility will be used to provide new natural gas supplies for the southwestern United States.

Also in December 2003, SELNG, British Petroleum and BPMiGas signed a non-binding Heads of Agreement (HOA) for the supply of 500 million cubic feet of gas a day from Indonesia's Tangguh LNG liquefaction facility to Energía Costa Azul. The non-binding HOA is expected to be the precursor to a full 20-year purchase/supply agreement.

Also in connection with this project, Mexico's national environmental agency issued an environmental permit in April 2003. Three other significant permits, an operating permit from Mexico's energy regulatory commission, a local land-use permit from the City of Ensenada and a coastal zone use permit, were granted in 2003. The permit to construct marine facilities is pending and expected to be received in the near future. In November 2003, a Mexican tribunal issued the equivalent of a preliminary injunction against a Mexican environmental agency's adoption of the environmental impact authorization covering the project. The injunction temporarily suspends the permit until the matter can proceed to a hearing on the merits of the authorization. Sempra Energy believes the suspension of these permits will be temporary and will not delay the 2007 commercial start date of the terminal.

Sempra Energy International

SEI's Mexican subsidiaries build and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico. On February 7, 2003, SEI purchased the remaining minority interests in its Mexican subsidiaries.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments are accounted for under the equity method when the company has an ownership interest of twenty to fifty percent. In these cases the company's pro rata shares of the subsidiaries' net assets are included in Investments on the Consolidated Balance Sheets, and are adjusted for the company's share of each investee's earnings or losses, dividends and foreign currency translation effects. Earnings are recorded as equity earnings in Other Income—Net on the Statements of Consolidated Income. The company accounts for certain investments in housing partnerships made before May 19, 1995 under the cost method, whereby they are amortized over ten years based on the expected residual value. The company has no unconsolidated subsidiaries where its ability to influence or control an investee differs from its ownership percentage.

The company's long-term investments are summarized as follows:

	December 31,	
(Dollars in millions)	**2003**	2002
Equity method investments:		
Chilquinta Energía	**$ 337**	$ 387
Luz del Sur	**177**	117
Sodigas Pampeana and Sodigas Sur	**66**	17
Elk Hills power project	**218**	172
El Dorado Energy	**68**	73
Sempra Energy Financial housing partnerships	**175**	206
Sempra Energy Financial synthetic fuel partnerships	**14**	8
Total	**1,055**	980
Cost method investments:		
Sempra Energy Financial housing partnerships	**47**	57
Other	**12**	3
Total	**59**	60
Investments in unconsolidated subsidiaries	**1,114**	1,040
Other:		
Mesquite power plant project		
Collateralized U.S. Treasury obligations*	**—**	228
Reimbursable project costs	**—**	45
Total	**—**	273
Total long-term investments	**$1,114**	$1,313

* The balance of $363 million at December 31, 2003 was reclassified to Short-Term Investments.

For equity method investments, costs in excess of equity in net assets were $232 million and $219 million at December 31, 2003 and 2002, respectively. 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 1). In accordance with SFAS 142, amortization ceased in 2002. Costs in excess of the underlying equity in net assets will continue to be reviewed for impairment in accordance with

APB Opinion 18, "The Equity Method of Accounting for Investments in Common Equity." See additional discussion of SFAS 142 in "New Accounting Standards" in Note 1. Descriptive information concerning each of these subsidiaries follows.

Sempra Energy International

SEI and PSEG Global (PSEG), an unaffiliated company, each own a 50-percent interest in Chilquinta Energía S.A., a Chilean electric utility, and 44 percent interests in Luz del Sur S.A.A. (Luz del Sur), a Peruvian electric utility.

SEI also owns 43 percent of two Argentine natural gas utility holding companies, Sodigas Pampeana S.A. and Sodigas Sur S.A. As a result of the devaluation of the Argentine peso at the end of 2001 and subsequent declines in the value of the peso, SEI had reduced the carrying value of its investment downward by a cumulative total of $197 million as of December 31, 2003. These non-cash adjustments continue to occur based on fluctuations in the Argentine peso. They do not affect net income, but increase or decrease other comprehensive income (loss) and accumulated other comprehensive income (loss).

The related Argentine economic decline and government responses (including Argentina's unilateral, retroactive abrogation of utility agreements early in 2002) continue to adversely affect the operations of these Argentine utilities. In 2002, SEI initiated arbitration proceedings under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments that has resulted from Argentine governmental actions. In 2003, SEI filed its legal brief with the International Center for Settlement of Investment Disputes, outlining its claims for $258 million. The company has also presented additional information that may provide a basis for a larger award. A decision is expected in early 2005. Sempra Energy also has a $48.5 million political-risk insurance policy under which it filed a claim to recover a portion of the investments' diminution in value.

Sempra Energy Resources

The 550-MW Elk Hills Power (Elk Hills) project, which is located near Bakersfield, California, began commercial operations in July 2003. Elk Hills is 50 percent owned by SER in a joint venture with Occidental Energy Ventures Corporation.

The 480-MW El Dorado power plant, located near Las Vegas, Nevada, began commercial operations in May 2000. The El Dorado Energy project is 50 percent owned by SER in a joint venture partnership with Reliant Energy Power Generation.

At December 31, 2003, the investments in U.S. Treasury obligations related to the Mesquite project was reclassified to Short-Term Investments as the result of the company buying out the lease in January 2004. See discussion in Note 1.

Sempra Energy Financial (SEF)

SEF invests as a limited partner in affordable-housing properties. SEF's portfolio includes 1,300 properties throughout the United States that are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also has an investment in a limited partnership which produces synthetic fuel from coal. Whether SEF will invest in additional properties will depend on Sempra Energy's income tax position. See additional discussion of income tax issues in Note 7.

NOTE 4. SHORT-TERM BORROWINGS

At December 31, 2003, the company had available $2.1 billion in unused, committed lines of credit to provide liquidity and support commercial paper.

Committed Lines of Credit

Sempra Energy Global Enterprises (Global) has two syndicated revolving credit agreements, each permitting revolving credit borrowings of $500 million. One is a 364-day credit agreement that may be converted into a one-year term loan upon the August 2004 expiration of the revolving credit period. The other is a three-year agreement permitting revolving credit borrowings until the expiration of the agreement in August 2006. Borrowings under the agreements are guaranteed by Sempra Energy and bear interest at rates varying with market rates and Sempra Energy's credit ratings. Both agreements require Sempra Energy to maintain a debt-to-total capitalization ratio (as identically defined in each agreement) of not to exceed 65 percent. Global had no commercial paper outstanding at December 31, 2003 and $422 million of commercial paper outstanding at December 31, 2002. As of December 31, 2003, a letter of credit for $18 million was outstanding under the second agreement.

SER has a syndicated $400 million revolving credit agreement guaranteed by Sempra Energy. The agreement requires Sempra Energy to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent. The agreement expires in August 2004 and borrowings bear interest at rates varying with market rates and Sempra Energy's credit rating. At December 31, 2003, SER had no outstanding borrowings under the agreement. At December 31, 2002, there was $100 million outstanding under the agreement. See Note 5 for additional information on SER's borrowings.

The California Utilities have a combined revolving line of credit, under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and the utility's credit rating. The revolving credit commitment expires in May 2004, at which time outstanding borrowings may be converted into a one-year term loan subject to any requisite regulatory approvals related to long-term debt. The agreement requires each utility to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default or preclude borrowings by the other. These lines of credit have never been drawn upon. At December 31, 2003 and 2002, the California Utilities had no commercial paper outstanding.

PE has a $375 million revolving agreement, guaranteed by Sempra Energy, for the purpose of providing loans to Global. The revolving credit commitment, initially $500 million, and $375 million at December 31, 2003, declines semi-annually by $125 million until expiration on April 5, 2005. Borrowings are guaranteed by Sempra and are subject to mandatory repayment prior to the maturity date should SoCalGas' unsecured long-term credit ratings cease to be at least BBB by Standard & Poor's (S&P) and Baa2 by Moody's Investor Services, Inc. (Moody's), should Sempra Energy's or SoCalGas' debt-to-total capitalization ratio (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 bear interest at rates varying with market rates, PE's credit ratings and the amount of outstanding borrowings. This line of credit has never been used.

Uncommitted Lines of Credit

SET has $770 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. At December 31, 2003, SET had $420 million of letters of credit, but no short-term borrowings, outstanding against these lines. The corresponding amounts outstanding at December 31, 2002 were $345 million and $115 million, respectively.

Other

Sempra Energy Solutions had $28 million of short-term debt with an average interest rate of 7.56% outstanding at December 31, 2003 and $33 million at December 31, 2002. Sempra Energy had no other short-term debt at December 31, 2003. The company's weighted average interest rate for short-term borrowings outstanding at December 31, 2002 was 2.02%.

NOTE 5. LONG-TERM DEBT

(Dollars in millions)	December 31, 2003	2002
First mortgage bonds		
4.375% January 15, 2011	**$ 100**	$ —
Variable rates after fixed to floating rate swaps (1.43% at December 31, 2003) January 15, 2011	**150**	—
4.8% October 1, 2012	**250**	250
6.8% June 1, 2015	**14**	14
5.45% April 15, 2018	**250**	—
5.9% June 1, 2018	**68**	68
5.9% to 6.4% September 1, 2018	**176**	176
6.1% September 1, 2019	**35**	35
Variable rates (1.25% at December 31, 2003) September 1, 2020	**58**	58
5.85% June 1, 2021	**60**	60
6.875% November 1, 2025	**175**	175
5.25% to 7% December 1, 2027	**225**	225
5.75% November 15, 2003	**—**	100
7.375% March 1, 2023	**—**	100
7.5% June 15, 2023	**—**	125
Total	**1,561**	1,386
Other long-term debt		
Variable rates (2.02% to 5.12% at December 31, 2003) September 2005	**630**	—
5.60% equity units May 17, 2007	**600**	600
Notes payable at variable rates after a fixed-to-floating rate swap (2.49% at December 31, 2003) July 1, 2004	**500**	500
7.95% Notes March 1, 2010	**500**	500
6.0% Notes February 1, 2013	**400**	—
6.95% Notes December 1, 2005	**300**	300
Rate-reduction bonds, 6.31% to 6.37% annually through 2007	**263**	329
5.9% June 1, 2014	**130**	130
Debt incurred to acquire limited partnerships, secured by real estate, at 7.13% to 9.35% annually through 2009	**110**	145
Employee Stock Ownership Plan		
Bonds at 7.375% November 1, 2014	**82**	82
Bonds at variable rates (1.65% at December 31, 2003) November 1, 2014	**19**	19
Variable rates (1.45% at December 31, 2003) December 1, 2021	**60**	60
Variable rates (1.46% at December 31, 2003) July 1, 2021	**39**	39
6.75% March 1, 2023	**25**	25
6.375% May 14, 2006	**8**	8
5.67% January 18, 2028	**5**	75
Other variable-rate debt	**15**	18
Capitalized leases	**8**	10
SER line of credit at variable rates August 21, 2004	**—**	100
Market value adjustments for interest rate swaps — net (expires July 1, 2004)	**23**	42
	5,278	4,368
Current portion of long-term debt	**(1,433)**	(281)
Unamortized discount on long-term debt	**(4)**	(4)
Total	**$ 3,841**	$4,083

Excluding capital leases, which are described in Note 15, and market value adjustments for interest-rate swaps, maturities of long-term debt are $1.4 billion in 2004, $397 million in 2005, $101 million in 2006, $682 million in 2007, $8 million in 2008 and $2.7 billion thereafter.

On January 26, 2004, SoCalGas optionally redeemed its $175 million 6.875% first mortgage bonds. Therefore that liability is classified as current at December 31, 2003. On January 21, 2004, SER elected to purchase the assets of Mesquite Trust and extinguish the $630 million of related debt outstanding. Therefore that liability also is classified as short-term at December 31, 2003. 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 credit agreements (which are generally renewed upon expiration and which are described in Note 4), it is expected that the bonds will be held to the maturities stated above. Interest rates on the $500 million of notes maturing in 2004 can vary with the company's credit ratings.

Issuances of $900 million, $1.2 billion and $675 million of long-term debt, and payments of $601 million, $479 million and $681 million on long-term debt were made in 2003, 2002 and 2001, respectively.

Callable Bonds

At the company's option, certain bonds are callable at various dates. Of the company's callable bonds, $873 million are callable in 2004, $105 million in 2005, $8 million in 2006 and $45 million thereafter.

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, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $2.8 billion of first mortgage bonds at December 31, 2003.

During the first quarter of 2001, SDG&E remarketed $150 million of variable-rate first mortgage bonds for various terms at a fixed rate of 7%. $45 million of these bonds came to term on December 1, 2003 and were remarketed to maturity with a rate of 5.25%. At SDG&E's option, the remaining bonds may be remarketed at a fixed or floating rate at December 1, 2005, the expiration of the fixed terms.

In November 2001, SoCalGas optionally redeemed its $150 million 8.75% first mortgage bonds. In December 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. In September 2002, SoCalGas terminated the swap, receiving cash proceeds of $10 million, comprised of $4 million in accrued interest and a $6 million amortizable gain.

In June 2002, SDG&E paid at maturity its $28 million 7.625% first mortgage bonds. In July 2002 the company optionally redeemed its $10 million 8.5% first mortgage bonds.

In August 2002, SoCalGas paid at maturity its $100 million 6.875% first mortgage bonds. In October 2002, SoCalGas publicly offered and sold $250 million of 4.8% first mortgage bonds, maturing on October 1, 2012. The bonds are not subject to a sinking fund and are redeemable prior to maturity only through a make-whole mechanism. Proceeds from the bond sale were used to replenish amounts previously expended to refund and retire indebtedness, and for working capital and other general corporate purposes.

On April 7, 2003, SoCalGas optionally redeemed its $100 million 7.375% first mortgage bonds. On August 21, 2003, SoCalGas optionally redeemed its $125 million 7.5% first mortgage bonds.

On October 17, 2003, SoCalGas issued $250 million of 5.45% first mortgage bonds due in April 2018. The proceeds were used to replenish amounts previously expended to refund and retire indebtedness and for general corporate purposes. On November 17, 2003, SoCalGas paid off its $100 million 5.75% first mortgage bonds.

On December 15, 2003, SoCalGas issued $250 million of 4.375% first mortgage bonds maturing in January 2011. The proceeds were used to retire outstanding debt and for other general corporate purposes. On December 15, 2003, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on $150 million of the 4.375% first mortgage bonds for a floating rate.

Mesquite Power

The company consolidated Mesquite Trust, the owner of Mesquite Power, on its financial statements as of December 31, 2003 as a result of implementing FIN 46. The debt outstanding was $630 million comprised of notes payable due in 2005 at various interest rates. On January 21, 2004, SER elected to purchase all of the power plant assets of Mesquite Trust for $631 million and extinguished the related Mesquite debt. Therefore the liability is classified as short-term at December 31, 2003. See further discussion under New Accounting Standards in Note 1. For additional information on the Mesquite Power synthetic lease, refer to Note 2.

Equity Units

In April and May of 2002, the company publicly offered and issued $600 million of Equity Units. For additional information on Equity Units refer to Note 12.

Unsecured Long-term Debt

Various long-term obligations totaling $2.7 billion are unsecured at December 31, 2003.

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. In June 2001, the company issued $500 million of 6.8% notes due July 1, 2004. Sempra Energy has a fixed-to-floating rate swap on these notes. In October 2001, SoCalGas paid at maturity its $120 million of 6.38% medium-term notes.

SER borrowed $100 million on its $400 million line of credit in October 2002 and repaid it in March 2003. There were no loans outstanding on SER's line of credit at December 31, 2003. This agreement expires in August 2004 and bears interest at rates varying with market rates and Sempra Energy's credit ratings. For additional information regarding this line of credit see Note 4.

On January 15, 2003, $70 million of SoCalGas' 5.67% $75 million medium-term notes were put back to the company. The remaining $5 million matures in 2028.

In January 2003, the company issued $400 million of long-term 6% notes due in February 2013. The bonds are not subject to a sinking fund and are redeemable prior to maturity only through a make-whole mechanism. The proceeds were used to pay down commercial paper.

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. They are being repaid over ten years by SDG&E's residential and small-commercial customers through a specified 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.

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

The Trust covers substantially all of the employees of the parent organization, SoCalGas and most of Global's subsidiaries. The Trust is used to fund part of the retirement savings plan described in Note 8. The 15-year notes are repriced weekly and subject to repurchase by the company at the holder's option, depending on market demand. 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 percent for three years. The variable interest rate and weekly repricing resume in May 2004. ESOP debt was reduced by $4.2 million during the last three years when 70,000 shares of company common stock were released from the Trust in order to fund the employer contribution to the company savings plan. Interest on the ESOP debt amounted to $6 million in 2003, $7 million in 2002 and $6 million in 2001. Dividends used for debt service amounted to $2 million in 2003, $3 million in 2002, and $3 million in 2001.

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. The schedule of long-term debt reflects past swap interest rates. The company believes the swaps have been fully effective in their purpose of converting the underlying debt's fixed rates to floating rates and meet the criteria for accounting under one of the methods defined in SFAS 133 for fair value hedges of debt instruments. Accordingly, market value adjustments to long-term debt of ($19) million and $20 million were recorded in 2003 and 2002, respectively, to reflect, without affecting net income or other comprehensive income, the favorable or (unfavorable) economic consequences (as measured at December 31, 2003 and 2002) of having entered into the swap transactions.

During 2002 and 2001, SDG&E had an interest-rate swap agreement that effectively fixed the interest rate on $45 million of variable-rate underlying debt at 5.4 percent. This floating-to-fixed-rate swap did 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. The effect on net income was a $1 million gain in 2002 and a $1 million loss in 2001.

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 that are intended to compensate for local inflation and currency exchange-rate fluctuations. In addition to establishing such tariff-based protections, the company offsets 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 last three years primarily as a result of decoupling the Argentine peso from the U.S. dollar, as discussed in Note 3.

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, 2003, are as follows:

(Dollars in millions)	SONGS*	Southwest Powerlink
Percentage ownership	20%	89%
Utility plant in service	$—	$237
Accumulated depreciation and amortization	$—	$141
Construction work in progress	$—	$ 27

* SDG&E's 20% ownership in SONGS has been fully recovered and is no longer included under utility plant and accumulated depreciation.

As of December 31, 2003, the company has fully recovered its interest in SONGS through the ICIP mechanism. Additional information concerning the ICIP mechanism is provided in Note 13.

The company and the other owners each hold its interest as an 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.

SONGS Decommissioning

Objectives, work scope and procedures for the 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 is estimated to be $316 million in 2003 dollars. Cost studies are updated every three years, with the next update expected to be submitted to the CPUC for its approval in 2005. 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 the costs allowed by regulators. Collections are authorized to continue until 2013, but may be extended by CPUC approval until 2022, at which time the SONGS' operating license ends and the decommissioning of SONGS 2 and 3 would be expected to begin. Payments to the nuclear decommissioning trusts (described in "Nuclear Decommissioning Trusts") are expected to continue until 2013 at which time sufficient funds are expected to be collected to fully decommission SONGS. If funds are not sufficient, additional future rate recovery is expected to occur.

The amounts collected in rates are invested in the externally managed trust funds. The securities held by the nuclear decommissioning trusts are considered available for sale. These trusts are shown on the Consolidated Balance Sheets at market value. At December 31, 2003, these trusts reflected unrealized gains of $159 million with the offsetting credits recorded on the Consolidated Balance Sheets to Asset Retirement Obligations and the related regulatory liabilities. At December 31, 2002, these trusts reflected unrealized gains of $95 million with the offsetting credits recorded to Deferred Credits and Other Liabilities and the related regulatory liabilities.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed and disposed of. Preparations have been made for the remaining major work to be performed in 2004 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 completion of an on-site storage facility for Unit 1 spent fuel. These activities are expected to be completed in 2008.

See discussion regarding the impact of SFAS 143 in Note 1.

Nuclear Decommissioning Trusts

SDG&E has established a Nonqualified Nuclear Decommissioning Trust and a Qualified Nuclear Decommissioning Trust to provide funds for the decommissioning of SONGS as described above. Amounts held by these trusts are invested in accordance with CPUC regulations that 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 these trusts must be invested passively.

At December 31, 2003 and 2002, trust assets were allocated as follows (dollars in millions):

	Qualified Trust		Nonqualified Trust	
	2003	2002	**2003**	2002
Domestic equity	**$163**	$143	**$43**	$36
Foreign equity	**88**	69	**—**	—
Total equity	**251**	212	**43**	36
Total fixed income	**249**	220	**27**	26
Total	**$500**	$432	**$70**	$62

Customer contribution amounts are determined by estimates of after-tax investment returns, decommissioning costs and decommissioning cost escalation rates. Lower actual investment returns or higher actual decommissioning costs would result in an increase in customer contributions.

Additional information regarding SONGS is included in Notes 13 and 15.

NOTE 7. INCOME TAXES

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

	Years ended December 31,		
	2003	2002	2001
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Utility depreciation	**6.7**	5.2	5.9
State income taxes—net of federal income tax benefit	**7.0**	7.0	6.4
Tax credits	**(22.6)**	(18.5)	(13.7)
Income from unconsolidated foreign subsidiaries	**(4.3)**	(2.0)	(3.0)
Settlement of Internal Revenue Service audit	**(11.2)**	(3.6)	—
Other—net	**(4.3)**	(2.9)	(1.5)
Effective income tax rate	**6.3%**	20.2%	29.1%

The components of total income (loss) from operations (including continuing extraordinary items) before income taxes are as follows:

(Dollars in millions)	Years ended December 31, 2003	2002	2001
Domestic	**$ 551**	$ 584	$ 651
Foreign	**191**	137	80
Total income before income taxes	**$ 742**	$ 721	$ 731

The components of income tax expense are as follows:

(Dollars in millions)	Years ended December 31, 2003	2002	2001
Current:			
Federal	**$ 93**	$ 195	$ 36
State	**16**	30	60
Foreign	**11**	13	11
Total	**120**	238	107
Deferred:			
Federal	**(138)**	(113)	104
State	**53**	31	1
Foreign	**18**	(5)	7
Total	**(67)**	(87)	112
Deferred investment tax credits	**(6)**	(5)	(6)
Total income tax expense	**$ 47**	$ 146	$ 213

Accumulated deferred income taxes at December 31 relate to the following:

(Dollars in millions)	2003	2002
Deferred tax liabilities:		
Differences in financial and tax bases of property, plant and equipment	**$1,094**	$ 883
Balancing accounts and regulatory assets	**314**	298
Partnership income	**34**	45
Unrealized revenue	**63**	53
Other	**211**	266
Total deferred tax liabilities	**1,716**	1,545
Deferred tax assets:		
Investment tax credits	**61**	62
General business tax credit carryforward	**192**	148
Net operating losses of foreign entities	**112**	89
Postretirement benefits	**31**	32
Other deferred liabilities	**190**	157
Restructuring costs	**—**	40
Compensation-related items	**134**	154
Bad debt allowance	**28**	—
State income taxes	**57**	46
Credits from Alternative Minimum Tax	**74**	19
Valuation allowance	**(20)**	(10)
Other	**100**	28
Total deferred tax assets	**959**	765
Net deferred income tax liability	**$ 757**	$ 780

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

(Dollars in millions)	**2003**	2002
Current (asset) liability	**$123**	$ (20)
Noncurrent liability	**634**	800
Total	**$757**	$780

In connection with its affordable-housing investments, the company has $192 million of unused general business tax credits in varying amounts dating back to 1999. The ability to offset these credits against future taxable income will expire between the years 2019 and 2022. The company expects to utilize the credits in future years. In addition, the company has $74 million of alternative minimum tax credits with no expiration date. All of these credits have been included in the company's calculation of income tax expense.

Foreign subsidiaries have $340 million in unused net operating losses available to reduce future income taxes, primarily in Mexico, Canada and the United Kingdom. Utilization of these losses began to expire in 2002. Financial statement benefits have been recorded on all but $66 million of these losses, primarily by offsetting them against deferred tax liabilities with the same expiration pattern and country of jurisdiction. No benefits have been recorded on $66 million of the losses because they have been incurred in jurisdictions where utilization is sufficiently in doubt.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($360 million at December 31, 2003), since they are expected to be reinvested indefinitely outside the U.S. It is not possible to predict the amount of U.S. income taxes that might be payable if these earnings were eventually repatriated.

Section 29 Income Tax Credits

In 2003 the Internal Revenue Service (IRS) issued Announcement 2003-46, stating it has reason to question the scientific validity of testing procedures and results related to Section 29 income tax credits. The notice also announced that it would suspend the issuance of new rulings until its review is complete and that rulings could be revoked if the IRS did not determine that the test procedures demonstrate a significant chemical change between the feedstock coal and the synthetic fuel. The IRS completed its review and on October 29, 2003, announced that it would again be issuing private letter rulings based on the previous requirements. Many such rulings have been issued since that date, including one involving operations owned by the company. The Permanent Subcommittee on Investigations of the U.S. Senate's Committee on Governmental Affairs has initiated an investigation on the subject of these income tax credits. In January 2004, the company received a letter from the Committee requesting certain information about its synthetic fuel operations and it is in the process of responding to this inquiry.

As part of its recently commenced normal audit program for the company for the period 1998-2001, the IRS notified the company of its intention to audit the synthetic fuel operations of SET and SEF. From acquisition of the facilities in 1998 through December 31, 2003, the company has recorded Section 29 income tax credits of $251 million of which $107 million were recorded for the year ended December 31, 2003. The company believes disallowance of Section 29 income tax credits is unlikely.

Luz del Sur

The Peruvian tax authorities (SUNAT) had assessed additional taxes for 1999 based on their challenge of Luz del Sur's revaluation of its assets and also previously announced that they would assess additional taxes for the years 1996 through 1998 for the same concept. The Peruvian Tax Court recently ruled that no additional taxes could be assessed for 1996 through 1998 and that any additional taxes for 1999 could only be assessed if the SUNAT showed that Luz del Sur had revalued its assets beyond their market value. If the SUNAT is successful in its challenge, income tax deductions for depreciation will be reduced, resulting in additional income taxes, interest and penalties aggregating as much as $10 million for the company's share for the period being questioned (1999) and $12 million for subsequent periods. The company believes that it has substantial defenses to such challenges and that the imposition of any additional taxes is not probable.

Spanish Holding Company

The IRS has issued Notice 2003-50, stating that regulations will be issued that will adversely affect foreign tax credit utilization by companies with "stapled-stock" affiliates. The company's intermediate parent company for many of its non-domestic subsidiaries is such a company. Although not probable, the most adverse resolution of this issue could result in a charge to net income of $13 million by the company.

Resolution of Certain Internal Revenue Service Matters

The company favorably resolved matters related to various prior years' returns during 2003. The primary issue involving the treatment of utility balancing accounts for the California Utilities was resolved following the issuance of an IRS Revenue Ruling and resolution of factual issues involving these claims with the IRS. The total effect on after-tax earnings and future cash flows for all IRS issues was $118 million, of which $79 million was at SDG&E and $29 million was at SoCalGas.

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 has funded and unfunded noncontributory defined benefit plans that together cover substantially all of its employees. The plans provide defined benefits based on years of service and final average salary.

The company also has other postretirement benefit plans covering substantially all of its employees. The life insurance plans are noncontributory and the health care plans are contributory, with participants' contributions adjusted annually. Other postretirement benefits include retiree life insurance, medical benefits for retirees and their spouses and Medicare Part B reimbursement for certain retirees.

The company maintains dedicated assets in support of its Supplemental Executive Retirement Plan.

During 2002, the company had amendments reflecting retiree cost of living adjustments, which resulted in an increase in the pension plan benefit obligation of $51 million. Amendments to other postretirement benefit plans related to the transfer of employees to SDG&E and changes to their specific benefits resulted in a decrease in the benefits obligation of $7 million. The amortization of these changes will affect pension expense in future years.

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

There were no amendments to the company's pension and other postretirement benefit plans in 2003.

December 31 is the measurement date for the pension and other postretirement benefit plans.

The following tables provide a reconciliation of the changes in the plans' projected benefit obligations during the latest two years, the fair value of assets and a statement of the funded status as of the latest two year ends:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2003**	2002	**2003**	2002
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	**$2,290**	$2,010	**$ 797**	$ 590
Service cost	**52**	57	**19**	13
Interest cost	**152**	149	**55**	42
Actuarial loss	**285**	197	**116**	191
Benefit payments	**(201)**	(187)	**(33)**	(32)
Plan amendments	**—**	51	**—**	(7)
Other	**—**	13	**—**	—
Net obligation at December 31	**2,578**	2,290	**954**	797
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	**1,984**	2,449	**409**	469
Actual return on plan assets	**453**	(281)	**90**	(50)
Employer contributions	**27**	3	**53**	22
Benefit payments	**(201)**	(187)	**(33)**	(32)
Fair value of plan assets at December 31	**2,263**	1,984	**519**	409
Benefit obligation, net of plan assets at December 31	**(315)**	(306)	**(435)**	(388)
Unrecognized net actuarial loss	**273**	283	**317**	266
Unrecognized prior service cost	**83**	93	**(13)**	(14)
Unrecognized net transition obligation	**1**	1	**—**	—
Net recorded asset (liability) at December 31	**$ 42**	$ 71	**$(131)**	$(136)

The following table provides the amounts recognized on the Consolidated Balance Sheets (in Noncurrent Sundry Assets**,** Deferred Credits and Other Liabilities, and Postretirement Benefits Other Than Pensions) at December 31:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	**2003**	2002	**2003**	2002
Prepaid benefit cost	**$ 178**	$ 203	**$ —**	$ —
Accrued benefit cost	**(136)**	(132)	**(131)**	(136)
Additional minimum liability	**(118)**	(93)	**—**	—
Intangible asset	**9**	12	**—**	—
Accumulated other comprehensive income, pretax	**109**	81	**—**	—
Net recorded asset (liability)	**$ 42**	$ 71	**$(131)**	$(136)

The accumulated benefit obligation for defined benefit pension plans was $2.4 billion and $2 billion at December 31, 2003 and 2002, respectively. The following table provides information concerning pension plans with benefit obligations in excess of plan assets as of December 31.

	Projected Benefit Obligation Exceeds the Fair Value of Plan Assets		Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	
(Dollars in millions)	**2003**	2002	**2003**	2002
Projected benefit obligation	**$2,341**	$2,091	**$815**	$736
Accumulated benefit obligation	**$2,126**	$1,849	**$793**	$684
Fair value of plan assets	**$2,011**	$1,757	**$538**	$468

The following table provides the components of net periodic benefit costs (income) for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
(Dollars in millions)	**2003**	2002	2001	**2003**	2002	2001
Service cost	**$ 52**	$ 57	$ 49	**$ 19**	$ 13	$ 11
Interest cost	**152**	149	141	**55**	42	41
Expected return on assets	**(161)**	(204)	(219)	**(35)**	(39)	(39)
Amortization of:						
Transition obligation	**1**	1	1	**9**	9	10
Prior service cost	**9**	7	6	**(1)**	(1)	(1)
Actuarial (gain) loss	**9**	(18)	(39)	**10**	—	(3)
Special termination benefit	**—**	—	13	**—**	—	—
Curtailment cost (credit)	**—**	—	1	**—**	—	—
Settlement credit	**—**	—	(19)	**—**	—	—
Regulatory adjustment	**(14)**	32	51	**(4)**	25	30
Total net periodic benefit cost (income)	**$ 48**	$ 24	$ (15)	$ 53	$ 49	$ 49

The significant assumptions related to the company's pension and other postretirement benefit plans are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	**6.00%**	6.50%	**6.00%**	6.50%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31:				
Discount rate	**6.50%**	7.25%	**6.50%**	7.25%
Expected return on plan assets	**7.50%**	8.00%	**7.30%**	7.80%
Rate of compensation increase	**4.50%**	4.50%	**4.50%**	4.50%

The expected long-term rate of return on plan assets is derived from historical returns for broad asset classes consistent with expectations from a variety of sources, including pension consultants and investment advisors.

	2003	2002
ASSUMED HEALTH CARE COST TRENDS RATES AT DECEMBER 31:		
Health-care cost trend rate	**30.00%***	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	**5.50%**	6.50%
Year that the rate reaches the ultimate trend	**2008**	2004

* This is the weighted average of the increases for all health plans. The 2003 rate for these plans ranged from 15% to 40%.

Assumed health-care cost trend rates have a significant effect on the amounts reported for the health-care plan costs. 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	$ 13	$ (11)
Effect on the health-care component of the accumulated other postretirement benefit obligation	$152	$(121)

Pension Plan Investment Strategy

The asset allocation for the company's pension trust (which includes other postretirement benefit plans, except for those described below) at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2004	**2003**	2002
U.S. Equity	45%	**45%**	44%
Foreign Equity	25%	**30%**	26%
Fixed Income	30%	**25%**	30%
Total	100%	**100%**	100%

The company's goal is to remain within a reasonable risk tolerance shown above. Its investment strategy is to stay fully invested at all times and maintain its strategic asset allocation, keeping the investment structure relatively simple. The equity portfolio is balanced to maintain risk characteristics similar to the S&P 1500 with respect to market capitalization, industry and sector exposures. The foreign equity portfolios are managed to track the MSCI Europe, Pacific Rim and Emerging Markets indexes. Bond portfolios are managed with respect to the Lehman Aggregate Index. The plan does not invest in Sempra Energy securities.

Investment Strategy for SoCalGas' Other Postretirement Benefit Plans

The asset allocation for SoCalGas' other postretirement benefit plans at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31, 2003	2002
U.S. Equity	70%	**71%**	63%
Fixed Income	30%	**27%**	34%
Cash	—	**2%**	3%
Total	100%	**100%**	100%

SoCalGas' other postretirement benefit plans, which are distinct from other postretirement benefit plans included in the company's pension trust (see above), are funded by cash contributions from SoCalGas and the retirees. The asset allocation is designed to match the long-term growth of the plan's liability. This plan is managed using 100% index funds.

Investment Strategy for SDG&E's Postretirement Health Plans

The asset allocation for SDG&E's postretirement health plans at December 31, 2003 and 2002 and the target allocation for 2004 by asset categories are as follows:

Asset Category	Target Allocation 2004	Percentage of Plan Assets at December 31, 2003	2002
U.S. Equity	25%	**26%**	23%
Foreign Equity	5%	**5%**	4%
Fixed Income	70%	**69%**	73%
Total	100%	**100%**	100%

SDG&E's postretirement health plans, which also are distinct from other postretirement benefit plans included in the company's pension trust (see above), pay premiums to the health maintenance organization and point-of-service plans from company and participant contributions. The company's investment strategy is to match the long-term growth rate of the liability primarily through the use of tax-exempt California municipal bonds.

Future Payments

The company expects to contribute $32 million to the pension plans and $62 million to its other postretirement benefit plans in 2004.

The following table reflects the total benefits expected to be paid to current employees and retirees from the plans or from the company's assets, including both the company's share of the benefit cost and, where applicable, the participants' share of the costs, which is funded by participant contributions to the plans.

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2004	$ 164	$ 35
2005	$ 167	$ 41
2006	$ 200	$ 44
2007	$ 184	$ 47
2008	$ 192	$ 49
Thereafter	$1,078	$270

Savings Plans

The company offers trusteed savings plans to all eligible employees. Eligibility to participate in the plans is immediate for salary deferrals. Employees may contribute, subject to plan provisions, from one percent to 25 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 contributions are equal to 50 percent of the first 6 percent of eligible base salary contributed by employees and, if certain company goals are met, an additional amount related to incentive compensation payments.

Employer contributions are invested in company stock and must remain so invested until termination of employment or until the employee's attainment of age 55, when they may be transitioned into other investments. At the direction of the employees, the employees' contributions are invested in company stock, mutual funds, institutional trusts or guaranteed investment contracts. The plans of certain non-wholly owned subsidiaries prohibit investments in Sempra Energy stock. In this case, the employer matching contributions are invested to mirror the employee-directed contributions. 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 $22 million in 2003, $20 million in 2002 and $17 million in 2001. The market value of company stock held by the savings plan was $675 million and $533 million at December 31, 2003 and 2002, respectively.

Employee Stock Ownership Plan

All contributions to the ESOP Trust (See Note 5) are made by the company; there are no contributions made by the participants. As the company makes contributions, 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. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.4 million shares and 2.6 million shares, respectively, of Sempra Energy common stock, with fair values of $71.6 million and $61.0 million, at December 31, 2003 and 2002, 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 2003, 2002 and 2001, 1,359,500, 544,100, and 777,500 shares of restricted company stock, respectively, were awarded to key employees. The corresponding weighted average market values of the shares at the time of grant were $24.42, $24.77 and $23.37, respectively. Subject to earlier forfeitures upon termination of employment, the 2003 award is scheduled to vest at the end of four years if performance-based goals are satisfied. The 2002 and 2001 awards are scheduled to vest at the end of seven years, but are also 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 except for senior officers, whose dividends are conditional. Compensation expense for the issuance of restricted stock was $16 million in 2003, $7 million in 2002 and $5 million in 2001.

In 2003, 2002 and 2001, Sempra Energy granted to officers and key employees 1,848,000, 3,444,300 and 2,934,800 stock options, respectively. The option prices were equal to the market price of common stock at the dates of grant. The options vest over four-year periods and expire 10 years from the dates of grant, subject to earlier expiration upon termination of employment. Compensation expense (or reduction thereof) for stock option grants (all associated with outstanding options with dividend equivalents that were issued before 2000—see below) and similar awards was $6 million, ($2 million) and $7 million in 2003, 2002 and 2001, respectively.

As of December 31, 2003, 13,410,138 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 with the stock option grants. This provides 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 that have included dividend equivalents have made the dividend equivalents dependent 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 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 123, the company adopted only its disclosure requirements and continues to account for stock-based compensation in accordance with the provisions of APB Opinion 25. See additional discussion of SFAS 148, the amendment to SFAS 123, in Note 1.

STOCK OPTION ACTIVITY

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITH DIVIDEND EQUIVALENTS			
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
Exercised	(172,358)	$19.87	
Cancelled	(68,124)	$24.03	
December 31, 2002	3,079,865	$22.48	2,777,590
Exercised	**(876,391)**	**$20.81**	
Cancelled	**(17,649)**	**$24.72**	
Transfer (see table below)	**(1,536,775)**	**$23.24**	
December 31, 2003	**649,050**	**$22.89**	**649,050**

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
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
Granted	3,444,300	$24.71	
Exercised	(223,430)	$17.70	
Cancelled	(84,137)	$21.70	
December 31, 2002	13,011,187	$22.18	5,287,437
Granted	**1,848,000**	**$24.44**	
Exercised	**(1,050,199)**	**$20.16**	
Cancelled	**(111,906)**	**$23.83**	
Transfer (see table above)	**1,536,775**	**$23.24**	
December 31, 2003	**15,233,857**	**$22.69**	**8,610,732**

Additional information on options outstanding at December 31, 2003, is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Remaining Life	Weighted Average Exercise Price
Outstanding Options			
$ 16.12-$ 19.06	3,348,195	6.04	$18.79
$ 20.36-$ 22.65	5,082,028	6.14	$21.76
$ 23.45-$ 27.64	7,452,684	5.12	$25.05
	15,882,907	5.64	$22.68
Exercisable Options			
$ 16.12-$ 19.06	2,302,520		$18.75
$ 20.36-$ 22.65	3,734,303		$21.50
$ 23.45-$ 27.64	3,222,959		$25.65
	9,259,782		$22.26

The grant-date market value of each option grant (including dividend equivalents where applicable) was estimated using a modified Black-Scholes option-pricing model. Weighted average grant-date market values for options granted in 2003, 2002 and 2001 were $4.31, $4.45 and $4.29, respectively.

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

	2003	2002	2001
Stock price volatility	**25%**	22%	24%
Risk-free rate of return	**1.8%**	4.8%	4.6%
Annual dividend yield	**2.2%**	4.1%	4.3%
Expected life	**6 Years**	6 Years	6 Years

NOTE 10. FINANCIAL INSTRUMENTS

Fair Value

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

	2003		2002	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	**$ 236**	**$ 352**	$ 271	$ 346
First mortgage bonds	**$1,561**	**$1,578**	$1,386	$1,452
Notes payable	**1,700**	**1,842**	1,300	1,424
Equity units	**600**	**680**	600	577
SDG&E rate-reduction bonds	**263**	**284**	329	357
Debt incurred to acquire limited partnerships	**110**	**128**	145	169
Mesquite Power debt	**630**	**630**	—	—
Other long-term debt	**414**	**436**	608	623
Total long-term debt	**$5,278**	**$5,578**	$4,368	$4,602
Due to unconsolidated affiliates	**$ 362***	**$ 392**	$ 162	$ 185
Preferred stock of subsidiaries	**$ 203***	**$ 184**	$ 204	$ 168
Mandatorily redeemable trust preferred securities	**$ —***	**—**	$ 200	$ 205

* $200 million of mandatorily redeemable trust preferred securities have been reclassified to Due to Unconsolidated Affiliates and $24 million of mandatorily redeemable preferred stock of subsidiaries have been reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets.

The fair values of investments in limited partnerships accounted for under the equity and cost methods 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 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 of subsidiaries 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

The company follows the guidance of SFAS 133 and related amendments SFAS 138 and 149 (collectively SFAS 133) to account for its derivative instruments and hedging activities. Derivative instruments and related hedges are recognized as either assets or liabilities on the balance sheet, measured at fair value. Changes in the fair value of derivatives are recognized in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure.

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. The ineffective portion is reported in earnings immediately. The effect on other comprehensive income for the years ended

December 31, 2003 and 2002 was not material. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in the Statements of Consolidated Income.

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in commodity prices, which are subject to significant and often volatile fluctuation. Derivative 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. The company classifies its forward contracts as follows:

Contracts that meet the definition of normal purchase and sales generally are long-term contracts that are settled by physical delivery and, therefore, are eligible for the normal purchases and sales exception of SFAS 133. The contracts are accounted for under accrual accounting and recorded in Revenues or Cost of Sales on the Statements of Consolidated Income when physical delivery occurs. Due to the adoption of SFAS 149, the company has determined that its natural gas contracts entered into after June 30, 2003 generally do not qualify for the normal purchases and sales exception.

Electric and Natural 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 Consolidated Balance Sheets 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 when certain criteria are met. When a contract no longer meets the requirements of SFAS 133, the unrealized gains and losses and the related regulatory asset or liability will be amortized over the remaining contract life.

The following were recorded on the Consolidated Balance Sheets at December 31 related to derivatives:

(Dollars in millions)	**2003**	2002
Fixed-priced contracts and other derivatives:		
Current liabilities	**$148**	$153
Noncurrent liabilities	**680**	813
Total	**828**	966
Current assets	**26**	3
Noncurrent assets	**—**	42
Total	**26**	45
Net liabilities	**$802**	$921

Regulatory assets and liabilities related to derivatives held by the California Utilities at December 31 were:

(Dollars in millions)	**2003**	2002
Regulatory assets and liabilities:		
Current regulatory assets	**$144**	$151
Noncurrent regulatory assets	**650**	812
Total	**794**	963
Current regulatory liabilities	**1**	2
Net regulatory assets	**$793**	$961

As of December 31, 2003, the difference between net liabilities and net regulatory assets was primarily due to $30 million related to a derivative contract associated with the purchase of the Cameron LNG facility offset by $23 million related to a fixed-to-floating interest rate swap. At December 31, 2002, the difference was primarily due to market value adjustment of $42 million related to two fixed-to-floating interest rate swaps. The market value adjustment in 2002 included a reversing effect for the cancellation of one of the swap agreements on September 30, 2002. $2 million of losses in 2003 and $4 million of income in 2002 were recorded in Operating Revenues and $1 million of income in 2002 was recorded in Other Income—Net in the Statements of Consolidated Income.

Market Risk

The company's policy is to use physical and financial derivative instruments to reduce its exposure to fluctuations in interest rates, foreign currency exchange rates and commodity prices. The company also uses and trades derivative instruments in its trading and marketing of energy and other commodities. Transactions involving these instruments are with major exchanges and other firms believed to be creditworthy. The use of these instruments exposes the company to market and credit risks, 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. This is described in Note 5.

Energy Derivatives

The company utilizes derivative instruments to reduce its exposure to unfavorable changes in energy prices, which are subject to significant and often volatile fluctuation. Derivative 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.

Energy Contracts

The California Utilities record transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and 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 majority of the California Utilities' contracts result in physical delivery, which is infrequent at the trading operations.

Sempra Energy Trading and Sempra Energy Solutions

SET derives revenue from market making and trading activities, as a principal, in natural gas, electricity, petroleum products, metals and other commodities, for which it quotes bid and ask 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. SET utilizes derivative instruments to reduce its exposure to unfavorable changes in market prices, which are subject to significant and often volatile fluctuation. These instruments include futures, forwards, swaps and options, and represent contracts with counterparties under which 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. Sempra Energy guarantees many of SET's transactions.

SES derives a major portion of its revenue from delivering electric and natural gas supplies to its commercial and industrial customers. Such contracts are hedged to preserve margin and reduce market risk. The derivative instruments used to hedge the transactions include swaps, forwards, futures, options or combinations thereof.

Trading instruments are recorded by both SET and SES on a trade-date basis and the majority of such derivative instruments are adjusted daily to current market value with gains and losses recognized in Other Operating Revenues on the Statements of Consolidated Income. These instruments are included on the Consolidated Balance Sheets as Trading Assets or Trading Liabilities and include amounts due from commodity clearing organizations, amounts due to or from trading counterparties, unrealized gains and losses from exchange-traded futures and options, derivative OTC swaps, forwards and options. Unrealized gains and losses on OTC transactions reflect amounts that 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 netting arrangement. Other derivatives which qualify as hedges are accordingly recorded under hedge accounting.

As a result of the rescission of EITF 98-10 (see Note 1), energy commodity inventory is being recorded at the lower of cost or market; however metals inventories continue to be recorded at fair value in accordance with ARB No. 43. As of December 31, 2003 and 2002, trading assets included commodity inventory of $1.4 billion and $2.0 billion, respectively. Note 2 discusses SET acquisitions made in 2002, some of which were affected by EITF 98-10.

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.

Based on quarterly measurements, the average fair values during 2003 for trading assets and liabilities approximate $5.1 billion and $4.4 billion, respectively. For 2002, the amounts were $4.9 billion and $3.7 billion, respectively.

The carrying values of trading assets and trading liabilities approximate the following:

(Dollars in millions)	December 31, 2003	2002
TRADING ASSETS		
SET:		
Unrealized gains on swaps and forwards	**$1,043**	$1,226
OTC commodity options purchased	**459**	480
Due from trading counterparties	**2,184**	1,279
Due from commodity clearing organizations and clearing brokers	**134**	49
Commodities owned	**1,420**	1,968
Total	**5,240**	5,002
SES:		
Unrealized gains on swaps and forwards	**113**	96
Intercompany eliminations	**(103)**	(34)
Total	**$5,250**	$5,064
TRADING LIABILITIES		
SET:		
Unrealized losses on swaps and forwards	**$1,095**	$ 816
OTC commodity options written	**226**	569
Due to trading counterparties	**2,195**	1,196
Repurchase obligations	**866**	1,511
Commodities not yet purchased	**56**	—
Total	**4,438**	4,092
SES:		
Unrealized losses on swaps and forwards	**35**	6
Intercompany eliminations	**(16)**	(4)
Total	**$4,457**	$4,094

At SET, market risk arises from the potential for changes in the value of physical and financial instruments resulting from fluctuations in prices and basis for natural gas, electricity, petroleum, petroleum products, metals and other commodities. 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 reduced by SES' hedging strategy as described above.

SET's credit risk from physical and financial instruments as of December 31, 2003 is represented by their positive fair value after consideration of collateral. Options written do not expose SET to credit risk. Exchange-traded futures and options are not deemed to have significant credit exposure since 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, 2003 and 2002, expressed in terms of net replacement value. These exposures are net of collateral in the form of customer margin and/or letters of credit of $569 million and $240 million at December 31, 2003 and 2002, respectively.

(Dollars in millions)	December 31, 2003	2002
Counterparty credit quality*		
SET:		
Commodity exchanges	**$ 134**	$ 49
AAA	**5**	69
AA	**310**	194
A	**463**	316
BBB	**345**	559
Below investment grade	**357**	504
Total	**$1,614**	$1,691
SES:		
AA	**$ 6**	$ 8
A	**21**	11
BBB	**26**	24
Below investment grade and not rated	**68**	86
Total	**$ 121**	$ 129

* As determined by rating agencies or internal models intended to approximate rating-agency determinations.

NOTE 11. PREFERRED STOCK OF SUBSIDIARIES

(Dollars in millions, except call/redemption price)	Call/ Redemption Price	December 31, 2003	2002
Not subject to mandatory redemption:			
Pacific Enterprises:			
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:			
$25 par value, authorized 1,000,000 shares:			
6% Series, 28,041 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:			
$20 par value, authorized 1,375,000 shares:			
5% Series, 375,000 shares outstanding	$ 24.00	**8**	8
4.5% Series, 300,000 shares outstanding	$ 21.20	**6**	6
4.4% Series, 325,000 shares outstanding	$ 21.00	**7**	7
4.6% 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		**79**	79
Total not subject to mandatory redemption		**179**	179
Subject to mandatory redemption:			
SDG&E:			
Without par value: $1.7625 Series, 950,000 and 1,000,000 shares outstanding at December 31, 2003 and December 31, 2002, respectively	$ 25.00	**24***	25
Total preferred stock		**$203**	$204

* Reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities.

PE preferred stock is callable at the applicable redemption price for each series, plus any unpaid dividends. The preferred stock is subject to redemption at PE's option at any time upon not less than 30 days' notice, at the applicable redemption price for each series, together with 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.

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 callable at December 31, 2003. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2004 to 2007; the remaining 750,000 shares must be redeemed in 2008. On January 15, 2004, SDG&E redeemed 50,000 shares at $25 per share.

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 2003, 2002 and 2001, the effect of dilutive options was equivalent to an additional 2,742,000, 1,059,000 and 1,745,000 shares, respectively. This is based on 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. The calculation excludes options covering 0.1 million, 6.0 million and 2.1 million shares for 2003, 2002 and 2001, respectively, for which the exercise price was greater than the average market price for common stock during the respective year.

Additional dilution could arise from the Equity Units described below. Through December 31, 2003, the price of the company's common stock was high enough to cause such dilution on only two days and, therefore, the Equity Units had no dilutive effect. On January 31, 2004, the common stock price was $31.14. If the price had averaged that for the full year of 2003, the Equity Units would have reduced the company's earnings per share in 2003 by $0.01.

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:

	2003	2002	2001
Common shares outstanding, January 1	**204,911,572**	204,475,362	201,927,524
Common stock issuance	**16,500,000**	—	—
Savings plan issuance*	**1,436,526**	—	—
Shares released from ESOP	**170,613**	130,486	134,645
Stock options exercised	**1,926,590**	395,788	1,009,948
Long-term incentive plan	**1,359,500**	544,100	777,500
Common stock investment plan**	**728,241**	212,411	762,439
Shares repurchased	**(262,286)**	(818,639)	(76,264)
Shares forfeited and other	**(172,137)**	(27,936)	(60,430)
Common shares outstanding, December 31	**226,598,619**	204,911,572	204,475,362

* In prior years, the plan purchased shares in the open market to cover these contributions.

** Participants in the Direct Stock Purchase Plan may reinvest dividends to purchase newly issued shares.

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 the amounts that are available for dividends and loans to the company from the California Utilities. At December 31, 2003, SDG&E and SoCalGas could have provided a total of $290 million and $175 million, respectively, to Sempra Energy, through dividends and loans. At December 31, 2003, SDG&E and SoCalGas had loans to Sempra Energy net of intercompany payables, of $75 million and $21 million, respectively.

Equity Units

During the second quarter of 2002, the company issued $600 million of Equity Units. Each unit consists of $25 principal amount of the company's 5.60% senior notes due May 17, 2007 and a contract to purchase for $25 on May 17, 2005, between .8190 and .9992 of a share of the company's common stock (with the precise number to be determined by the then-prevailing market price). The number of shares to be issued ranges from 20 million to 24 million. The Equity Units are recorded as Long-Term Debt on the Consolidated Balance Sheets. Through December 31, 2003, $55 million had been charged to the common stock account in connection with the transaction.

Common Stock Offering

On October 14, 2003, Sempra Energy completed a common stock offering of 16.5 million shares priced at $28 per common share, resulting in net proceeds of $448 million. The proceeds were used primarily to pay off short-term debt.

NOTE 13. ELECTRIC INDUSTRY REGULATION

Background

The restructuring of California's electric utility industry has significantly affected the company's electric utility operations, and the power crisis of 2000-2001 caused the CPUC to significantly modify its plan for restructuring the electricity industry. 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 customer bills to be substantially higher than normal. These higher prices were initially passed through to customers and resulted in bills that in most cases were double or triple those from 1999 and early 2000. This resulted in several legislative and regulatory responses, including California Assembly Bill (AB) 265. AB 265 imposed a ceiling on the cost of the electric commodity that SDG&E could pass on to its small-usage customers from June 1, 2000 to December 31, 2002.

SDG&E accumulated the amount that it paid for electricity in excess of the ceiling rate in an interest-bearing balancing account (the AB 265 undercollection) and began recovering these amounts in rates charged to customers following the end of the rate-ceiling period. At December 31, 2003, the AB 265 undercollection was $63 million (included in Regulatory Balancing Accounts—Net on the Consolidated Balance Sheets) and is being recovered in current rates.

Another legislative response to the power crisis resulted in the purchase by the DWR of a substantial portion of the power requirements of California's electricity users. Since early 2001, the DWR has procured power for the utility procurement customers of each of the California investor-owned utilities (IOUs) and the CPUC has established the allocation of the power and its related cost responsibility among the IOUs. Beginning on January 1, 2003, the IOUs resumed some of its electric commodity procurement, whereas previously the DWR had been purchasing the IOUs' entire net short position.

Department of Water Resources

The DWR's operating agreement with SDG&E, approved by the CPUC, governs SDG&E's administration of the allocated DWR contracts. The agreement provides that SDG&E is acting as a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. Legal and financial responsibility and risks associated with these activities will continue to reside with the DWR. Therefore, revenues and costs associated with the contracts were not included in the Statements of Consolidated Income during 2003. From February 2001 until December 2002, the DWR was purchasing similar amounts of power for SDG&E; the cost of that power was not included in the Statements of Consolidated Income in 2001 or 2002. The reasonableness of the IOU's administration and dispatch of the allocated contracts will be reviewed by the CPUC in an annual proceeding.

In September 2003, the CPUC approved a $1 billion refund to consumers of the three major California IOUs as a result of the DWR's lowering its revenue requirement for 2003. The refund was returned to customers in the form of a one-time bill credit. SDG&E's portion was 13.51 percent or about $135 million. The bill credit had no effect on SDG&E's net income and net cash flows because customer savings are coming from lower charges by the DWR, and SDG&E is merely transmitting the electricity from the DWR to the customers, without taking title to the electricity.

On January 8, 2004, the CPUC issued a decision on the final true-up of DWR's 2001/2002 energy costs among California's three major investor-owned electric utilities, resulting in SDG&E's customers being allocated $59 million of additional costs. The amount from this true-up is recoverable from ratepayers and will be included with SDG&E's allocated share of DWR's 2004 revenue requirement and incorporated into electric charges for 2004, which are expected to be decided in the first half of 2004. This true-up will have a short-term effect on SDG&E's cash flow but will not otherwise affect its results of operations, since SDG&E merely passes through the costs to its customers.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating DWR's Revenue Requirement beginning in 2004 through the remaining life of the DWR contracts. An interim allocation based on the current 2003 methodology was utilized beginning January 1, 2004, and is in effect until a decision is reached on a permanent methodology (expected in the second quarter of 2004). Once a permanent methodology is established, the impacts of the decision will be applied retroactively back to January 1, 2004. This delay could have an effect on SDG&E's rates and cash flows, but not on its net income.

Power Procurement

In October 2001, the CPUC initiated an Order Instituting Ratemaking (OIR) to establish ratemaking mechanisms that would enable California investor-owned electric utilities to resume purchasing electric energy and related services and hedging instruments to fulfill their obligation to serve and meet the needs of their customers. In so doing, the CPUC acknowledged that the utilities desired assurance of more timely regulatory review and cost recovery for their procurement activities and costs. In connection therewith, the OIR directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003. The net short position is the difference between the amount of electricity needed to cover a utility's customer demand and the power provided by owned generation and existing contracts, including the long-term DWR power contracts allocated to the customers of each IOU by the CPUC (see above).

The OIR also implemented recent legislation regarding procurement and renewables portfolio standards and establishes a process for review and approval of the utilities' long-term (20-year) procurement plans. In December 2002, the CPUC adopted SDG&E's 2003 short-term procurement plan. That plan addressed SDG&E's procurement activities in calendar year 2003, authorized contract terms for up to five years for transactions entered into under the plans, and allowed for the hedging of first quarter 2004 residual net short positions with transactions entered into in 2003. SDG&E was required to purchase approximately 10 percent of its customer requirements in 2003, based on the allocation of the DWR power approved by the CPUC in December 2002. The CPUC authorized SDG&E to acquire a variety of resource types and demand side resources. A semiannual cost review and rate revision mechanism is established, and a trigger is established for more frequent changes if undercollected commodity costs exceed five percent of annual, non-DWR generation revenues, to provide for timely recovery of any undercollections. Approval of SDG&E's 2003 short-term procurement plan provided for SDG&E's return to procurement of its customers' needs on January 1, 2003, consistent with the intent of the legislature and the CPUC.

SDG&E filed its 20-year long-term resource plan covering its anticipated procurement needs between 2004 and 2023 and its short-term procurement plans for its anticipated procurement activities in 2004. In decisions issued in December 2003 and January 2004, the CPUC approved the 2004 procurement plan and provided policy guidance for the filing of an updated 20-year resource plan in the spring of 2004.

On December 18, 2003, the CPUC issued a decision adopting SDG&E's procurement plan for 2004. The decision delayed until 2004 further CPUC direction on comprehensive policy guidance for the IOUs' long-term resource plans. In the decision, the CPUC continued its moratorium (subject to certain exceptions) on the IOUs' ability to deal with their own affiliates in procurement transactions.

SDG&E's 20-year resource plan identified the near-term need for firm capacity resources within its service territory to support transmission grid reliability. As a result, SDG&E issued a Request for Proposals (RFP) for the years 2005-2007 of 69 MW in 2005 increasing to 291 MWs in 2007.

In October 2003, SDG&E filed a motion in the Procurement OIR that now requests the CPUC to authorize SDG&E to enter into five new electric resource contracts. They include:

The 550-megawatt combined-cycle Palomar power plant in Escondido, California to be constructed by SER for completion in 2006.

The 45-MW Ramco combustion turbine which SDG&E is proposing to acquire as a turnkey project and intends to use for intermediate load requirements beginning June 2005.

(SDG&E will not take ownership of these two facilities unless appropriate cost recovery and ratemaking mechanisms are instituted by the CPUC to ensure that SDG&E recovers all reasonable costs of, and a reasonable return on, the investments.)

A power purchase agreement (PPA) to buy up to 570 MW over ten years starting in 2008 from a power plant that Calpine Corporation (Calpine) would complete on its site within SDG&E's service territory. (SDG&E would recommend the Calpine PPA only if the CPUC orders the implementation of certain critical conditions intended to make the Calpine PPA a positive economic benefit to SDG&E's customers.)

One contract each for a demand-response resource and a renewable resource.

The capital cost related to the five contracts proposed by SDG&E is $640 million. Hearings concluded on February 20, 2004, and a decision is expected in May 2004. Given the CPUC's prior denial of the company's request for approval of additional transmissions facilities, the company believes that customer requirements for electricity could not be met without the requested resources or similar additions.

A June 2003 CPUC decision in the Procurement OIR directed each IOU to procure from renewable sources at least one percent of its 2003 total energy sales, increasing to 20 percent by 2017. SDG&E procured four percent of its 2003 total energy sales from renewable sources and existing contracts will increase this to five percent in 2004 and nine percent in 2007. A 2002 CPUC resolution permits the company to credit toward future years' compliance any excess over its one-percent annual requirement.

On July 11, 2003, the CPUC adopted a proposed decision continuing the level of the Direct Access (DA) cost responsibility surcharge (CRS) cap effective July 1, 2003 at 2.7 cents per kilowatt hour (kWh), subject to possible revision in the next DA CRS cap review proceeding. In each periodic DA CRS cap review proceeding, the cap is subject to adjustment to the extent necessary to maintain the goal of refunding to utility customers the full amounts to which they are entitled by the end of the DWR contract term in 2011. The DA CRS has no impact on SDG&E; however, the surcharge may affect SES' ability to attract and maintain customers in California.

SONGS

Through December 31, 2003, the operating and capital costs of SONGS Units 2 and 3 were recovered through the ICIP mechanism which allowed SDG&E to receive 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affected net income. For the year ended December 31, 2003, ICIP contributed $53 million to SDG&E's net income. Beginning in 2004, the CPUC has provided for traditional rate-making treatment, under which the SONGS ratebase would start over at January 1, 2004, essentially eliminating earnings from SONGS except from future increases in ratebase.

FERC Actions

DWR Contract

On June 25, 2003, the FERC issued orders upholding the company's long-term energy supply contract with the DWR, as well as contracts between the DWR and other power suppliers. The order affirmed a previous FERC conclusion that those advocating termination or alteration of the contract would have to satisfy a "heavy" burden of proof, and cited its long-standing policy to recognize the sanctity of contracts. In the order, the CPUC noted that CPUC and court precedent clearly establish that allegations that contracts have become uneconomic by the passage of time do not render them contrary to the public interest under the Federal Power Act. The CPUC pointed out that the contracts were entered into voluntarily in a market-based environment. The CPUC found no evidence of unfairness, bad faith or duress in the original contract negotiations. It said there was no credible evidence that the contracts placed the complainants in financial distress or that ratepayers will bear an excessive burden. In December 2003, appeals of this matter filed by a number of parties, including the California Energy Oversight Board and the CPUC, were consolidated and assigned to the Ninth Circuit Court of Appeals (the Court). The company expects that the Court will affirm the FERC decision.

Refund Proceedings

The FERC is investigating prices charged to buyers in the PX and ISO markets by various electric suppliers. The FERC is seeking to determine the extent to which individual sellers have yet to be paid for power supplied during the period of October 2, 2000 through June 20, 2001 and to estimate the amounts by which individual buyers and sellers paid and were paid in excess of competitive market prices. Based on these estimates, the FERC could find that individual net buyers, such as SDG&E, are entitled to refunds and individual net sellers, such as SET, are required to provide refunds. To the extent any such refunds are actually realized by SDG&E, they would reduce SDG&E's rate-ceiling balancing account. To the extent that SET is required to provide refunds, they could result in payments by SET after adjusting for any amounts still owed to SET for power supplied during the relevant period (or receipts if refunds are less than amounts owed to SET).

In December 2002, a FERC Administrative Law Judge (ALJ) issued preliminary findings indicating that the California PX and ISO owe power suppliers $1.2 billion (the $3.0 billion that the California PX and ISO still owe energy companies less $1.8 billion that the energy companies charged California customers in excess of the preliminarily determined competitive market clearing prices). On March 26, 2003, the FERC largely adopted the ALJ's findings, but expanded the basis for refunds by adopting a staff recommendation from a separate investigation to change the natural gas proxy component of the mitigated market clearing price that is used to calculate refunds. The March 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion. The FERC recently released its final instructions, and ordered the ISO and PX to recalculate the precise number through their settlement models. California is seeking $8.9 billion in refunds from its electricity suppliers and has appealed the FERC's preliminary findings and requested rehearing of the March 26 order. SET and other power suppliers have joined in appeal of the FERC's preliminary findings and requested rehearing.

SET had established reserves of $29 million for its likely share of the original $1.8 billion. SET is unable to determine its possible share of the additional refund amount. Accordingly, it has not recorded any additional reserves but the company does not believe that any additional amounts that SET may be required to pay would be material to the company's financial position or liquidity.

Manipulation Investigation

The FERC is also investigating whether there was manipulation of short-term energy markets in the West that would constitute violations of applicable tariffs and warrant disgorgement of associated profits. In this proceeding, the FERC's authority is not confined to the October 2, 2000 through June 20, 2001 period relevant to the refund proceeding. In May 2002, the FERC ordered all energy companies engaged in electric energy trading activities to state whether they had engaged in various specific trading activities in violation of the PX and ISO tariffs (generally described as manipulating or "gaming" the California energy markets).

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. First, FERC directed 43 entities, including SET and SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. Second, the FERC directed more than 20 entities, including SET, to show cause why their activities during the period January 1, 2000 to June 20, 2001 did not constitute gaming and/or anomalous market behavior in violation of the tariffs. Remedies for confirmed violations could include disgorgement of profits and revocation of market-based rate authority. The FERC has encouraged the entities to settle the issues and on October 31, 2003, SET agreed to pay $7.2 million in full resolution of these investigations. The entire amount has been recorded as of December 31, 2003. The entire proceeding, including the settlement, is subject to final approval by the FERC, which is expected during 2004. SDG&E and the FERC resolved the matter by SDG&E's paying $28 thousand into a FERC-established fund.

On June 25, 2003, the FERC also determined that it was appropriate to initiate an investigation into possible physical and economic withholding in the California ISO and PX markets. For the purpose of investigating economic withholding, the FERC used an initial screen of all bids exceeding $250 per MW between May 1, 2000 and October 2, 2001. Both SDG&E and SET have received data requests from the FERC staff and have provided responses. The FERC staff will prepare a report to the FERC, which will be the basis to decide whether additional proceedings are warranted. SET and SDG&E believe that their bids and bidding procedures were consistent with ISO and PX tariffs and protocols and applicable FERC price caps. On August 1, 2003, the FERC staff issued an initial report that determined there was no need to further investigate particular entities, including SET, for physical withholding of generation.

NOTE 14. OTHER REGULATORY MATTERS

Natural Gas Industry Restructuring

In December 2001 the CPUC issued a decision related to natural gas industry restructuring (GIR), with implementation anticipated during 2002. On January 12, 2004, after many delays and changes, an ALJ issued a proposed decision that would implement the 2001 decision. The proposed decision would result in revising noncore balancing account treatment to exclude the balancing of SoCalGas' transmission costs; other noncore costs/revenues would continue to be fully balanced until the decision in the next Biennial Cost Allocation Proceeding (BCAP) (see below). On February 11, 2004, a member of the CPUC issued an alternative decision that would vacate the December 2001 decision and defer GIR matters to the Natural Gas Market OIR (see below). A CPUC decision could be issued in March 2004.

Natural Gas Market OIR

The Natural Gas Market OIR was approved on January 22, 2004, and will be addressed in two concurrent phases. The schedule calls for a Phase I decision by summer 2004 and a Phase II decision by the end of 2004. In Phase I the CPUC's objective is to develop a process enabling the CPUC to review and pre-approve new interstate capacity contracts before they are executed. In addition, the California Utilities must submit proposals on any LNG project to which interconnection is planned, providing costs and terms, including access to the pipelines in Mexico. Phase II will primarily address emergency reserves and ratemaking policies. The OIR invites proposals on how utilities should provide emergency reserves consisting of slack intrastate pipeline capacity, contracts for additional capacity on the interstate pipelines and an emergency supply of natural gas storage. The CPUC's objective in the ratemaking policy component of Phase II is to identify and propose changes to policies that create incentives that are consistent with the goal of providing adequate and reliable long-term supplies and that do not conflict with energy efficiency programs. The focus of the Gas OIR is 2006 to 2016. Since GIR (see above) would end in August 2006 and there is overlap between GIR and the Gas OIR issues, a number of parties (including SoCalGas) are advising the CPUC not to implement GIR.

The company believes that regulation needs to consider sufficiently the adequacy and diversity of supplies to California, transportation infrastructure and cost recovery thereof, hedging opportunities to reduce cost volatility, and programs to encourage and reward conservation.

Cost of Service

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs. The California Utilities are requesting revenue increases of $121 million. The CPUC's Office of Ratepayer Advocates (ORA) filed its prepared testimony on the applications in August 2003, recommending numerous rate decreases that would reduce annual revenues by $162 million from their current level. The Utility Consumers' Action Network (UCAN), a consumer-advocacy group, has proposed rates for SDG&E and The Utility Reform Network has proposed rates for SoCalGas that would reduce annual revenues by $88 million and $178 million, respectively, from their current level. Hearings concluded in November 2003. On December 19, 2003, settlements were filed with the CPUC that, if approved, would resolve most of the cost of service issues. The SoCalGas settlement was signed by SoCalGas and all parties active in its application. The SDG&E settlement was signed by SDG&E, ORA and other parties, but not by UCAN, the City of Chula Vista and other parties. The CPUC adopted a schedule for briefing and commenting on the proposed settlements that concluded on February 19, 2004. The SoCalGas settlement would reduce rates by $33 million from 2003 rates. The SDG&E settlement would reduce its electric rates by $19.6 million from 2003 rates and increase its natural gas rates by $1.8 million from 2003 rates. As part of the proposed settlement, SDG&E and the ORA would resolve their dispute concerning the allocation of the gain on sale of SDG&E's surplus property in Blythe, California, by increasing SDG&E's forecast of miscellaneous revenues by $1.3 million annually, thereby lowering its retail revenue requirement by that amount. The CPUC may accept one or both of the settlements or may adopt an outcome differing from both of the settlements. Resolution is likely in the second quarter of 2004.

On December 18, 2003, the CPUC issued a decision that creates memorandum accounts as of January 1, 2004, to record the difference between actual revenues and those that are later authorized in the CPUC's final decision in this case. The difference would then be amortized in rates. The

California Utilities have also filed for continuation through 2004 of existing performance-based regulation (PBR) mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but deferred action on applying any rewards or penalties for performance relative to these targets to a decision to be issued later in 2004 in a second phase of these applications discussed below.

The CPUC has established a procedural schedule for the second phase of these applications, addressing issues related to PBR (see below). The procedural schedule calls for hearings to be held in June 2004, with a decision during 2004. The scope of the second phase includes: (a) a formula for setting authorized cost of service for 2005 and succeeding years until the next full Cost of Service proceeding is scheduled; (b) whether and how rates should be adjusted if earned returns vary from authorized returns; and (c) prospective targets and rewards/penalties for service quality and safety.

An October 2001 decision denied the California Utilities' request to continue equal sharing between ratepayers and shareholders of the estimated savings for the 1998 business combination that created Sempra Energy and, instead, ordered that all of the estimated 2003 merger savings go to ratepayers. In 2002, merger savings to shareholders for the fourth quarter and for the year were $4 million and $17 million, respectively, at SoCalGas and $2 million and $8 million, respectively, at SDG&E. Pursuant to the decision, SoCalGas and SDG&E will return the 2003 merger savings related to natural gas operations of $83 million and $15 million, respectively, to ratepayers over a twelve-month period beginning January 1, 2004. The merger savings related to electric operations were previously returned to ratepayers.

Performance-Based Regulation

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted PBR for SDG&E effective in 1994 and for SoCalGas effective in 1997. PBR has resulted in modification to 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, rather than relying solely on expanding utility plant to increase earnings.

PBR consists of three primary components. The first is a mechanism to adjust rates in years between general rate cases or cost of service cases. Similar to the pre-PBR Attrition Proceeding, it annually adjusts general rates from those of the prior year to provide for inflation, changes in the number of customers and efficiencies.

The second component is a mechanism whereby any earnings in excess of those authorized plus a narrow band above that are shared with customers in varying degrees depending upon the amount of the additional earnings.

The third component consists of a series of measures of utility performance. Generally, if performance is outside of a band around the specified benchmark, the utility is rewarded or penalized certain dollar amounts.

The three areas that are eligible for PBR rewards or penalties are operational incentives based on measurements of safety, reliability and customer satisfaction; demand-side management (DSM) rewards based on the effectiveness of the programs; and natural gas procurement rewards or penalties. The CPUC is also considering a new reward/penalty related to electricity procurement, now that the utilities are resuming this activity. However, as noted under Cost of Service, Phase II of the California Utilities' current cost of service proceeding is not scheduled for completion until late 2004. As a result, it is possible that some or all of the safety, reliability and customer satisfaction incentive mechanisms (i.e., those that are reviewed in the Cost of Service proceeding) would not be in effect for 2004. Even if that were to occur, it is not expected that the effect would be other than a one-year moratorium on the mechanisms.

In July 2003, the CPUC issued a decision relative to SDG&E's Year 11 natural gas PBR application, which will permanently extend the PBR mechanism with some modification. The decision approved the Joint Parties' Motion for an Order Adopting Settlement Agreement filed by SDG&E and the ORA, which will apply to Year 10 and beyond. The effect of the modifications is to reduce slightly the potential size of future PBR rewards or penalties.

The Gas Cost Incentive Mechanism (GCIM) allows SoCalGas to receive a share of the savings it achieves by buying natural gas for customers below monthly benchmarks. The mechanism permits full recovery of all costs within a tolerance band above the benchmark price and refunds savings within a tolerance band below the benchmark price. The costs outside the tolerance band are shared between customers and shareholders.

Since the 1990s, IOUs have been eligible to earn awards for implementing and administering energy conservation and efficiency programs. The California Utilities have offered these programs to customers and have consistently achieved significant earnings from the program. On October 16, 2003, the CPUC issued a decision that the pre-1998 DSM earnings proceeding would not be reopened, leaving the earnings mechanism unchanged. The CPUC may adjust amounts determined pursuant to the earnings mechanism consistent with the application of known, standard measurement and verification protocols.

The CPUC has consolidated the 2000, 2001 and 2002 award applications. The 2003 award applications were filed on May 1, 2003. On May 2, 2003, the CPUC released RFPs to conduct a review of the IOUs' studies and reported program milestones/accomplishments used as the basis for the awards claims and program expenditures. The review should be completed in the second quarter of 2004. Additionally, the low-income awards will be subject to an independent review expected to commence in 2005. The majority of the outstanding claims are on hold pending completion of the independent review.

Incentive Awards Approved in 2003

PBR and GCIM rewards are not included in the company's earnings before CPUC approval is received. The following table reflects awards approved in 2003 (dollars in millions):

Program	SoCalGas	SDG&E	Total
GCIM/Natural Gas PBR	$48.2	$ 5.3	$53.5
Distribution/Other PBR	1.1	18.2	19.3
Total	$49.3	$23.5	$72.8

Pending Incentive Awards

At December 31, 2003, the following performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

Program	SoCalGas	SDG&E	Total
GCIM/Natural Gas PBR	$ 6.3	$ 1.9	$ 8.2
DSM/Energy Efficiency*	9.8	35.6	45.4
Total	$16.1	$37.5	$53.6

* Dollar amounts shown do not include interest, franchise fees or uncollectible amounts.

Cost of Capital

Effective January 1, 2003, SoCalGas' authorized rate of return on common equity (ROE) is 10.82 percent and its return on ratebase (ROR) is 8.68 percent. Effective January 1, 2003, SDG&E's authorized ROE is 10.9 percent and its ROR is 8.77 percent, for SDG&E's electric distribution and natural gas businesses. The electric-transmission cost of capital is determined under a separate FERC proceeding discussed below. These rates will continue to be effective until market interest-rate changes are large enough to trigger an automatic adjustment or until the CPUC orders a periodic review.

The objective of SDG&E's market-indexed capital adjustment mechanism is to revise SDG&E's rates to reflect changes in the six-month average of double-A rated utility bond rates, without lengthy Commission proceedings. The benchmark average is currently 7.24 percent, the six-month average at September 30, 2002, the year of SDG&E's last cost of capital proceeding. If in any year the difference between the current six-month average at September 30th and the benchmark exceeds 100 basis points, SDG&E's authorized ROE is adjusted by one-half of the difference, and the embedded costs of debt and preferred equity are adjusted to current levels. In addition, the triggering six-month average becomes the new benchmark until another automatic adjustment occurs. The six-month average was 6.32 percent at September 30, 2003 and, therefore, no triggering has occurred. The rate has not changed significantly since then.

SoCalGas' automatic adjustment mechanism provides for a trigger in any month when the 12-month trailing average of 30-year Treasury bond rates varies by greater than 150 basis points from the benchmark, and the current Global Insight forecast of the 30-year Treasury bond rate 12 months ahead varies by greater than 150 basis points from the benchmark. When these criteria are met, SoCalGas' authorized ROE is adjusted by one-half of the difference between the trailing 12-month average and the benchmark, and the embedded costs of debt and preferred equity are adjusted to current levels. Any time an automatic adjustment occurs, the new trailing 12-month average becomes the new benchmark. The benchmark is currently 5.38 percent, the 12-month trailing average of the 30-year Treasury bond as of October 2002. At December 31, 2003, the 12-month average of the 30-year Treasury bond was 4.92 percent and the estimated Global Insight year-ahead forecast was 5.90 percent and, therefore, no triggering has occurred. The rates have not changed significantly since then.

Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California-Arizona border between March 2000 and May 2001. If the investigation determines that the conduct of any party to the investigation contributed to the natural gas price spikes, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. On December 10, 2003, Southern California Edison filed testimony alleging that SoCalGas significantly contributed to the price spikes and exercised market power and recommended to the CPUC that SoCalGas divest its storage assets and revise its GCIM to an incentive mechanism that would simply reward SoCalGas if it managed to procure natural gas supplies in the producing basins at a price below market. Hearings are scheduled to begin in late March 2004 with a decision expected by late 2004. The company believes that the CPUC will find that SoCalGas acted in the best interests of its core customers.

Biennial Cost Allocation Proceeding

The BCAP determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the California Utilities and adjusts rates to reflect variances in customer demand as compared to the forecasts previously used in establishing transportation rates. SoCalGas and SDG&E filed with the CPUC their 2005 BCAP applications in September 2003, requesting updated transportation rates effective January 1, 2005. The most recent BCAP decision allocating the California Utilities non-commodity natural gas costs of service and revising their respective natural gas transportation rates and rate designs was issued in April 2000 and is still in effect. In November 2003, an Assigned Commissioner Ruling delayed the current BCAP applications until a decision is issued in the GIR implementation proceeding discussed above. As a result, SoCalGas is required to amend its BCAP application within 21 days of a decision in the GIR and SDG&E is required to amend its BCAP application seven days thereafter. As a result of the deferrals and the forecasted significant decline in noncore gas throughput on SoCalGas' system, in December 2002 the CPUC issued a decision approving 100 percent balancing account protection for SoCalGas' risk on local transmission and distribution revenues from January 1, 2003 until the CPUC issues its next BCAP decision. SoCalGas is seeking to continue this balancing account protection through 2006. A CPUC decision on GIR could result in revising noncore balancing account treatment to exclude the balancing of transmission costs; other noncore costs/revenues would continue to be fully balanced until the BCAP decision.

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. In January 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 requirements, as the IOUs have previously acknowledged in connection with the holding companies' formations. In January 2002 the CPUC ruled on jurisdictional issues, deciding that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed. The company's request for rehearing on the issues was denied by the CPUC and the company subsequently filed appeals in the California Court of Appeal. On November 26, 2003 the California Court of Appeal agreed to hear the company's appeal. Oral argument is set for March 5, 2004.

CPUC Investigation of Compliance with Affiliate Rules

In February 2003, the CPUC opened an investigation of the business activities of SDG&E, SoCalGas and Sempra Energy to determine if they have complied with statutes and CPUC decisions in the management, oversight and operations of their companies. In September 2003, the CPUC suspended the procedural schedule until it completes an independent audit to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of SDG&E and SoCalGas. The audit will cover years 1997 through 2003, is expected to commence in March 2004 and should be completed by the end of 2004. The scope of the audit will be broader than the annual affiliate audit. In accordance with existing CPUC requirements, the California Utilities' transactions with other Sempra Energy affiliates have been audited by an independent auditing firm each year, with results reported to the CPUC, and there have been no material adverse findings in those audits.

FERC Standards of Conduct

On November 25, 2003, the FERC established standards of conduct governing the relationship between transmission providers and their energy affiliates. They broaden the definition of an energy affiliate. Under the standards, SDG&E is a transmission provider and SoCalGas is an energy affiliate of SDG&E. The standards require transmission providers to offer service to all customers on a non-discriminatory basis. SER, SES and SET are also considered energy affiliates of SDG&E, and, among other things, SDG&E must apply the standards of conduct prohibiting unduly preferential information sharing with the energy affiliates. Impacts, if any, of the standards are being determined for SEI and SER.

FERC Transmission Cost of Service

On May 2, 2003, the FERC accepted SDG&E’s request for modification of its Transmission Owner Tariff to adopt a transmission rate formula that would allow SDG&E to recover its actual prudent costs for transmission service. New transmission rates, which are subject to refund based on the FERC’s final order, became effective October 1, 2003.

On December 18, 2003, the FERC approved the transmission formula, with rates effective October 1, 2003, whereby SDG&E’s rates would be adjusted annually to cover actual prudent costs, including an ROE of 11.25 percent on its actual equity as of December 31 of the prior year. SDG&E’s revenue requirements for its retail customers for the initial 12-month period beginning October 1, 2003, will be $142.1 million. SDG&E will fully recover its cancelled Valley-Rainbow Project costs of $19 million over a ten-year amortization period, with no return component. The transmission rate formula will be in effect through June 30, 2007.

Recovery of Certain Disallowed Transmission Costs

In August 2002 the FERC issued Opinion No. 458, which effectively disallowed SDG&E’s recovery of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink under the Participation Agreements and charges assessed to SDG&E under the ISO FERC tariff for transmission line losses and grid management charges related to energy schedules of Arizona Public Service Co. (APS) and the Imperial Irrigation District (IID), its Southwest Powerlink co-owners. As a result, SDG&E is incurring unreimbursed costs of $4 million to $8 million per year. On November 17, 2003, SDG&E petitioned the United States Court of Appeals for review of these FERC orders and argued that the disallowed costs should be allowed for recovery through the Transmission Revenue Balancing Account Adjustment. On February 12, 2004, on the FERC’s motion, the court remanded the case back to the FERC for further consideration, “based on the FERC’s representation that it intends to act expeditiously on remand.” The FERC has not yet issued further orders in this matter.

In a separate but related matter, on July 6, 2001, SDG&E filed an arbitration claim against the ISO, claiming the ISO should not charge SDG&E for the transmission losses attributable to energy schedules on the APS and IID shares of the Southwest Powerlink. As of October 2003 amounts under the claim totaled $22 million, including interest. The independent arbitrator found in SDG&E’s favor on this matter. The ISO appealed this result to the FERC and a FERC decision is expected in 2004. SDG&E has also commenced a private arbitration to reform the Participation Agreements to remove prospectively SDG&E’s obligation to provide services giving rise to unreimbursed ISO tariff charges.

Southern California Fires

Several major wildfires that began on October 26, 2003 severely damaged some of SDG&E’s infrastructure, causing a significant number of customers to be without utility services. On October 27, 2003, Governor Gray Davis declared a "state of emergency" for counties within SoCalGas' and SDG&E's service territory.

The declaration of a state of emergency authorizes a public utility to establish a catastrophic event memorandum account (CEMA) to record all incremental costs (costs not already included in rates) associated with the repair of facilities and the restoration of service. Electric distribution and natural gas related costs are recovered through the CEMA. Electric transmission related costs are recovered through the annual true-up FERC proceeding. The CEMA related costs are recoverable in rates separate from ordinary costs currently recovered in rates. The CPUC is required to hold expedited hearings in response to the utilities' request for recovery. Total fire-related costs are estimated to be $70 million and $5 million for SDG&E and SoCalGas, respectively, with $60 million and $1 million, respectively, incurred during 2003, the majority of which were capital related. At December 31, 2003, the CEMA account included $14 million of incremental operating and maintenance costs. The company expects to file a CEMA application sometime in 2004. The company expects no significant effect on earnings from the fires.

NOTE 15. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California Utilities buy natural gas under short-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. The California Utilities transport natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SoCalGas has commitments with pipeline companies for firm pipeline capacity under contracts that expire at various dates through 2007.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2004 and 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties.

At December 31, 2003, the future minimum payments under natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2004	$221	$767	$ 988
2005	211	11	222
2006	125	11	136
2007	21	2	23
2008	20	3	23
Thereafter	207	—	207
Total minimum payments	$805	$794	$1,599

Total payments under natural gas contracts were $2.2 billion in 2003, $1.4 billion in 2002 and $2.6 billion in 2001.

Purchased-Power Contracts

In January 2001, the California Assembly passed AB X1 to allow the DWR to purchase power under long-term contracts for the benefit of California consumers. In accordance with AB X1, SDG&E entered into an agreement with the DWR under which the DWR purchased 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 purchased-power contracts) through December 31, 2002. Starting on January 1, 2003, SDG&E and the other IOUs resumed their electric commodity procurement function based on a CPUC decision issued in October 2002. In April 2003, the CPUC approved an operating agreement between the DWR and SDG&E that bestows upon SDG&E the role of a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions for the DWR contracts. For additional discussion of this matter see Note 13.

For 2004, SDG&E expects to receive 49 percent of its customer power requirement from DWR allocations. Of the remaining requirements, SONGS is expected to account for 21 percent, long-term contracts for 19 percent and spot market purchases for 11 percent. The contracts expire on various dates through 2025. Prior to January 1, 2001, the cost of these contracts was recovered by bidding them into the 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 addition, during 2002 SDG&E entered into contracts which will provide five percent of its 2004 total energy sales from renewable sources. These contracts expire on various dates through 2021.

At December 31, 2003, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2004	$ 214
2005	224
2006	233
2007	240
2008	218
Thereafter	2,235
Total minimum payments	$3,364

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. Excluding DWR-allocated contracts, total payments under the contracts were $396 million in 2003, $235 million in 2002 and $512 million in 2001.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2004 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 3 percent to 6 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 included $36 million at December 31, 2003 and $35 million at December 31, 2002, related to these leases. The associated accumulated amortization was $23 million and $21 million, respectively. SDG&E terminated its capital lease agreement for nuclear fuel in mid-2001 and now owns its nuclear fuel.

At December 31, 2003, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

(Dollars in millions)	Operating Leases	Capitalized Leases
2004	$ 97	$ 4
2005	85	3
2006	77	1
2007	76	1
2008	69	1
Thereafter	213	1
Total future rental commitments	$617	11
Imputed interest (6% to 10%)		(3)
Net commitments		$ 8

In connection with the quasi-reorganization described in Note 1, 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 $35 million at December 31, 2003. These leases are included in the above table at the amounts provided in the lease.

Rent expense for operating leases totaled $98 million in 2003, $90 million in 2002 and $92 million in 2001. Depreciation expense for capitalized leases is included in Depreciation and Amortization on the Statements of Consolidated Income.

Global Construction Projects

Global has several subsidiaries which have developed or are in the process of constructing various capital projects in the United States and in Mexico. The following is a summary of construction projects developed or under development by the respective business units.

SER

SER acquires, develops and operates power plants throughout the U.S. and Mexico. As of the end of 2003, SER had five power plants in operations.

The 1,250-MW Mesquite Power plant commenced operations in two phases during 2003; the first phase of commercial operations began in June 2003 and the second phase started in December 2003. See further discussion on the Mesquite Power plant in Notes 1 and 2.

In the third quarter of 2003, SER completed construction and commenced operations of its $350 million 600-MW TDM power plant. The environmental issues concerning this facility are described under "Litigation" and in Note 2. TDM's natural gas from Ehrenberg, Arizona to the interconnection with Gasoducto Bajanorte is being delivered via the North Baja Pipeline. The transportation is provided through an agreement between SER and North Baja Pipeline LLC. Under the agreement, SER is obligated to pay a monthly reservation charge for the transport of certain quantities over a 20-year period. The future commitments related to this contract are $83 million.

In the third quarter of 2003, SER completed construction of the 550-MW Elk Hills power project located in Bakersfield, California. SER owns 50 percent of Elk Hills and has invested $219 million in Elk Hills through December 31, 2003.

On October 31, 2002, SER acquired the 305-MW Twin Oaks Power plant. In connection with the acquisition, SER also assumed a contract which includes annual commitments to purchase lignite coal either until an aggregate minimum volume has been achieved or through 2025. As of December 31, 2003, SER's future minimum payments under the lignite coal agreement totaled $455 million, for which payments of $29 million are due for 2004, $29 million for 2005, $25 million for 2006, $25 million for 2007, $25 million for 2008 and $322 million thereafter. The minimum payments have been adjusted for allowed shortfalls and 90 percent minimum contract requirements under the contract.

In August 2003, SER obtained approvals by the California Energy Commission for the company's planned 550-MW Palomar power plant in Escondido, California. The estimated two-year construction project will commence when power contracts for the project have been signed. SER currently is seeking contracts that would support advancement of the project. In January 2004, SDG&E contracted with SER to purchase the power plant from SER when construction is complete in 2006. The plant will then be owned and operated by SDG&E under CPUC regulation.

As of December 31, 2003, SER has no additional construction commitments concerning the facilities described above but has additional commitments of $7 million related to two natural gas turbines for use in future power plant development.

SELNG

SELNG is in the process of developing Energía Costa Azul, a major new LNG receiving terminal that will bring natural gas supplies into northwestern Mexico and Southern California. This is discussed in Note 2.

In April 2003, SELNG acquired Cameron LNG for $36 million. Additional payments are contingent on meeting certain benchmarks and milestones and the performance of the project. At December 31, 2003, the company has recorded a liability of $30 million related to this matter. The total cost of the project is expected to be about $700 million. The project could begin commercial operations as early as 2007.

SELNG currently leases land in Hackberry, Louisiana for the development of the Cameron LNG terminal. In connection with the purchase of Cameron LNG, SELNG and the lessor agreed to certain lease amendments, including an increase in the annual rent, addition of wharfage fees and extension of the lease term for another 30 years. The lease amendments are contingent upon obtaining project financing or commencement of construction. As of December 31, 2003, SELNG is still operating under the original land lease, which is up for renewal in February 2005. Accordingly, rent payments subsequent to January 2005 are not included in the table of future minimum rental payment obligations. Should the terms of the amended lease be triggered, total rent payments and wharfage fees would be $38 million over 30 years. See Note 2 for further discussion on the LNG facilities.

SEI

In 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico with a pipeline built by PG&E Corporation (PG&E) that connects to Arizona. The 30-inch pipeline can deliver up to 500 million cubic feet per day of natural gas to new generation facilities in Baja California, including SER's TDM power plant discussed above. Capacity on the pipeline is over 90 percent subscribed. The company had no additional construction costs or other commitments for this pipeline at December 31, 2003.

SER’s Contract with the DWR

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 MW of power to the state. SER may, but is not obligated to, deliver this electricity from its portfolio of plants in the western United States and Baja California, Mexico. If SER elects to use these plants to supply the DWR, those sales would comprise more than two-thirds of the projected capacity of the plants. 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. Information concerning the validity of this contract is provided under “Litigation—DWR Contract.” Information concerning the FERC’s orders upholding this contract and the pending appeal is provided in FERC Actions in Note 13.

Impact of Direct Access on SES

On March 21, 2002, the CPUC affirmed its decision prohibiting new direct access contracts after September 20, 2001, but rejected a proposal to make the prohibition retroactive to July 1, 2001. Contracts in place as of September 20, 2001 may be renewed or assigned to new parties. On November 7, 2002, the CPUC issued a decision adopting DA exit fees with an interim cap of 2.7 cents per kWh for rates effective January 1, 2003. The CPUC is conducting further proceedings to determine whether, and to what extent, the interim cap should be revised after July 1, 2003. The CPUC’s decisions concerning direct access could affect the motivation of potential customers to enter into contracts for SES to sell them electricity in California.

Environmental Issues

The company has identified no significant environmental issues outside the United States, except for the additional environmental impact studies the DOE is conducting of the TDM power plant. Additional information regarding the environmental studies is provided below under “Litigation.” The following discussion is related to environmental matters within the United States.

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 have occurred at the California Utilities. However, now that SER owns and operates several power plants and SELNG is developing LNG regasification terminals, additional environmental issues may arise. 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 (PRP) under the federal Superfund laws and comparable state laws. Costs incurred at the California Utilities to operate the facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Significant costs incurred to 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 $14 million in 2003, $8 million in 2002 and $6 million in 2001. The cost of compliance with these regulations over the next five years is not expected to be significant.

At the California Utilities, costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the expectation that these costs will be 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 (29 completed as of December 31, 2003 and 16 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 PRP (investigations and remediations are continuing) and mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS (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 the 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, 2003, the company's accrued liability for environmental matters was $61.4 million, of which $48.7 million related to manufactured-gas sites, $10.5 million to cleanup at SDG&E's former fossil-fueled power plants, $2.1 million to waste-disposal sites used by the company (which has been identified as a PRP) and $0.1 million to other hazardous waste sites. The accruals for the manufactured-gas and waste-disposal sites are expected to be paid ratably over the next three years. The accruals for SDG&E's former fossil-fueled power plants are expected to be paid ratably over the next two years.

Nuclear Insurance

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. The insurance policy provides $300 million in coverage, which is the maximum amount available. In addition to this primary financial protection, the Price-Anderson Act provides for up to $10.6 billion of secondary financial protection if the liability loss exceeds the insurance limit. Should any of the licensed/commercial reactors in the United States experience a nuclear liability loss which exceeds the $300 million insurance limit, all utilities owning nuclear reactors could be assessed under the Price-Anderson Act to provide the secondary financial protection. SDG&E and the other co-owners of SONGS could be assessed up to $201 million under the Price- Anderson Act. SDG&E's share would be $40 million unless a default were to occur by any other SONGS co-owner. In the event the secondary financial protection limit were insufficient to cover the liability loss, the Price-Anderson Act provides for Congress to enact further revenue-raising measures to pay claims. These measures could include an additional assessment on all licensed reactor operators.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance. The coverage also provides the SONGS owners up to $490 million for outage expenses/replacement power incurred because of accidental property damage. This coverage is limited to $3.5 million per week for the first 52 weeks, and $2.8 million per week for up to 110 additional weeks. There is a deductible waiting period of 12 weeks prior to receiving indemnity payments. The insurance is provided through a mutual insurance company owned by utilities with nuclear facilities. Under the policy's risk sharing arrangements, insured members are subject to retrospective premium assessments if losses at any covered facility exceed the insurance company's surplus and reinsurance funds. Should there be a retrospective premium call, SDG&E could be assessed up to $7.4 million.

Both the nuclear liability and property insurance programs include industry aggregate limits for terrorism-related SONGS losses, including replacement power costs.

Litigation

During 2003, the company recorded $49 million of after-tax charges related to litigation costs and a SoCalGas sublease. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations. Except for the matters referred to below, 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.

DWR Contract

In May 2003, the San Diego Superior Court granted SER's motion for summary judgment on its complaint regarding its contract with the DWR (and the DWR's cross-complaint seeking to void the 10-year energy-supply contract). The court determined that "(a) Sempra is entitled to provide electrical energy from any source, including Market Sources, (b) Sempra is not in breach of the Agreement as framed by the pleadings in this matter, (c) DWR is obligated to take delivery and pay for deliveries under the Agreement, and (d) Sempra has no obligation to complete any specific Project." The DWR filed a motion for a new trial claiming irregularities in the Court's judgment. The Court subsequently clarified its earlier summary judgment ruling and effectively denied the motion for new trial. An amended judgment was entered by the Court. The DWR has filed a notice of appeal on the judgments and the Court's clarification. A decision by the appellate court is expected sometime during 2005. The DWR continues to accept all scheduled power from SER and, although it has disputed billings in an immaterial amount and the manner of certain deliveries, it has paid all amounts that have been billed under the contract.

Antitrust Litigation

Class-action and individual lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso Energy Corp. (El Paso) and several of its affiliates, unlawfully sought to control natural gas and electricity markets. In March 2003, plaintiffs in these cases and the applicable El Paso entities announced that they had reached a $1.5 billion settlement, of which $125 million is allocated to customers of the California Utilities. The Court approved that settlement in December 2003. The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated.

Natural Gas Cases: Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that El Paso and certain Sempra Energy subsidiaries unlawfully sought to control the natural gas market in their respective states. In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, including Sempra Energy, the California Utilities and other company subsidiaries, seeking damages resulting from an alleged conspiracy to drive up or control natural gas prices, eliminate competition and increase market volatility, breach of contract and wire fraud. On January 27, 2004, the U.S. District Court dismissed the Sierra Pacific Resources case against all of the defendants, determining that this is a matter for the FERC.

Electricity Cases: Various lawsuits, which seek class-action certification, allege that Sempra Energy and certain company subsidiaries (SDG&E, SET and SER, depending on the lawsuit) unlawfully manipulated the electric-energy market. In January 2003, the applicable federal court granted a motion to dismiss a similar lawsuit on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act. That ruling has been appealed in the Ninth Circuit Court of Appeals, which is expected to hear the appeal in the first quarter of 2004. Similar suits filed in Washington and Oregon were voluntarily dropped by the plaintiffs without court intervention in June 2003. In addition, in May 2003, the Port of Seattle filed an action alleging that a number of energy companies, including Sempra Energy, SER and SET, unlawfully manipulated the electric energy market and committed wire fraud. That action has been transferred to San Diego Federal District Court and is currently pending a motion to dismiss on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act.

SER, SET and SDG&E, along with all other sellers in the western power market, have been named defendants in a complaint filed at the FERC by the California Attorney General's office seeking refunds for electricity purchases based on alleged violations of FERC tariffs. The FERC has dismissed the complaint. The California Attorney General has filed an appeal in the 9th Circuit.

Price Reporting Practices

In the fourth quarter of 2002, Sempra Energy and SoCalGas were named as defendants in a lawsuit filed in Los Angeles Superior Court against various trade publications and other energy companies alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications. On July 8, 2003, the Superior Court granted the defendants' demurrer on the grounds that the claims contained in the complaint were subject to the Filed Rate Doctrine and were preempted by the Federal Power Act. Plaintiffs filed an amended complaint, and in September 2003 defendants filed a demurrer to the amended complaint, which was granted in part. In December 2003, the plaintiffs dismissed both Sempra Energy and SoCalGas from the lawsuit. In May 2003 and again in February 2004, similar actions were filed in San Diego Superior Court against Sempra Energy and SET, and the May 2003 action has been removed to Federal District Court. Another lawsuit containing identical allegations was filed against Sempra Energy and SET in Federal District Court in November of 2003. In addition, in August 2003, a lawsuit was filed in the Southern District of New York against Sempra Energy and SES, alleging that the prices of natural gas options traded on the NYMEX were unlawfully increased under the Federal Commodity Exchange Act by defendants' manipulation of transaction data to natural gas trade publications. In November of 2003, another suit containing identical allegations was filed and consolidated with the New York action. In December 2003, plaintiffs dismissed Sempra Energy from these cases and in January 2004, SES was also dismissed. On January 20, 2004, plaintiffs filed an amended consolidated complaint that named SET as a defendant in this lawsuit.

In January 2004, the Commodity Futures Trading Commission (CFTC) issued a subpoena to SoCalGas and SET in connection with the CFTC's "Activities Affecting the Price of Natural Gas in the Fall of 2003" investigation. The company is cooperating with the CFTC in the investigation.

Other

On August 21, 2003, the CPUC denied a rehearing requested by opponents of its December 2002 decision that had approved a settlement with SDG&E allocating between SDG&E customers and shareholders the profits from intermediate-term purchase power contracts that SDG&E had entered into during the early stages of California's electric utility industry restructuring. As previously reported, the settlement provided $199 million of these profits to customers, by reductions to balancing account undercollections in prior years. The settlement provided the remaining $173 million of profits to SDG&E shareholders, of which $57 million had been recognized for financial reporting purposes in prior years. As a result of the decision, SDG&E recognized additional after-tax income of $65 million in the third quarter of 2003. UCAN, a consumer-advocacy group which had requested the CPUC rehearing, appealed the decision to the California Court of Appeals and the court agreed to hear the case. Oral arguments are likely to occur in March or April 2004. A decision is expected by the third quarter of 2004. The company expects that the Court of Appeals will affirm the CPUC's decision.

SER was a defendant in an action brought by Occidental Energy Ventures Corporation (Occidental) with respect to the Elk Hills power project being jointly developed by the two companies. On

September 30, 2003, the arbitration proceeding found in favor of SER, determining that SER had not breached its joint development contract with Occidental.

In May 2003, a federal judge issued an order finding that the DOE's abbreviated assessment of two Mexicali power plants, including SER's TDM plant, failed to evaluate the plants' environmental impact adequately and called into question the U.S. permits they received to build their cross-border transmission lines. In July 2003, the judge ordered the DOE to conduct additional environmental studies and denied the plaintiffs' request for an injunction blocking operation of the transmission lines, thus allowing the continued operation of the TDM plant. The DOE has until May 15, 2004, to demonstrate why the court should not set aside the permits.

In 1999, Sempra Energy and PSEG each acquired a 44-percent interest in Luz Del Sur, a Peruvian electric distribution company. Local law required that assets built with government funds be purchased by the local utility and added to rate base. A dispute arose between the government and Luz Del Sur over the amount of compensation due for the 194 projects transferred to Luz Del Sur by the government. The government claims the amount owed was $36 million. Luz Del Sur argued that the amount was less and the matter was settled with the government for approximately $10 million. Following a change in the Peruvian government, a criminal charge was filed against certain government officials, and utility officials as accomplices, including the chief executive officer and chief financial officer of Luz Del Sur, alleging that the settlements were inadequate. In September 2003 a Peruvian court ordered the prosecutor's case to be dismissed. Although the prosecutor has indicated no evidence of wrongdoing in the case, the prosecutor has appealed this decision and the case rests in a higher Peruvian court. A decision is expected during the first half of 2004.

At December 31, 2003, SET remains due approximately $100 million from energy sales made in 2000 and 2001 through the ISO and the PX markets. The collection of these receivables depends on satisfactory resolution of the financial difficulties being experienced by other California IOUs as a result of the California electric industry crisis. SET has submitted relevant claims in the PG&E and PX bankruptcy proceedings. The company believes adequate reserves have been recorded.

FERC Actions

Information regarding FERC actions related to the company is provided in Note 13.

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. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

Electric Distribution System Conversion

Under a CPUC-mandated program, the cost of which is included in utility rates, 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, 2003, the aggregate unexpended amount of this commitment was $90 million. Capital expenditures for underground conversions were $28 million in 2003, $33 million in 2002 and $12 million in 2001.

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 and counterparties, substantially all of whom are located in their service territories, which together cover most of Southern California and a portion of central California.

As described above, SER has a contract with the DWR to supply up to 1,900 MW of power to the state over 10 years, beginning in 2001. SER would be at risk for the amounts of outstanding billings and the continued viability of the contract if the DWR were to default on its payments under this contract. At any given time, the average outstanding billings related to this contract is $50 million to $60 million.

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 netting arrangements whenever possible and, where appropriate, obtains collateral or other security such as lock-box liens and downgrade triggers. 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 16. SEGMENT INFORMATION

The company has four separately managed reportable segments comprised of SoCalGas, SDG&E, SET and SER. The California Utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SoCalGas is a natural gas distribution utility, serving customers throughout most of Southern California and part of central California. SDG&E provides electric service to San Diego and southern Orange counties and natural gas service to San Diego County. SET, based in Stamford, Connecticut, is a wholesale trader of physical and financial energy products and other commodities, and a trader and wholesaler of metals, serving a broad range of customers in the United States, Canada, Europe and Asia. SER acquires, develops and operates power plants throughout the U.S. and Mexico.

The accounting policies of the segments are described in Note 1, and segment performance is evaluated by management based on reported net income. California Utility transactions are based on rates set by the CPUC and FERC.

(Dollars in millions)	Years ended December 31, 2003	2002	2001
OPERATING REVENUES			
Southern California Gas Company	**$3,544**	$2,858	$3,716
San Diego Gas & Electric	**2,311**	1,725	2,362
Sempra Energy Trading	**1,144**	821	1,047
Sempra Energy Resources	**671**	349	178
All other	**274**	332	458
Intersegment revenues	**(57)**	(37)	(31)
Total	**$7,887**	$6,048	$7,730
INTEREST INCOME			
Southern California Gas Company	**$ 34**	$ 5	$ 22
San Diego Gas & Electric	**42**	10	21
Sempra Energy Trading	**12**	11	11
Sempra Energy Resources	**14**	4	6
All other	**132**	84	73
Intercompany elimination	**(130)**	(72)	(50)
Total	**$ 104**	$ 42	$ 83
DEPRECIATION AND AMORTIZATION			
Southern California Gas Company	**$ 289**	$ 276	$ 268
San Diego Gas & Electric	**242**	230	207
Sempra Energy Trading	**23**	21	27
Sempra Energy Resources	**13**	2	1
All other	**48**	67	76
Total	**$ 615**	$ 596	$ 579
INTEREST EXPENSE			
Southern California Gas Company	**$ 45**	$ 44	$ 68
San Diego Gas & Electric	**73**	77	92
Sempra Energy Trading	**30**	43	14
Sempra Energy Resources	**25**	6	7
All other	**265**	196	192
Intercompany elimination	**(130)**	(72)	(50)
Total	**$ 308**	$ 294	$ 323
INCOME TAX EXPENSE (BENEFIT)			
Southern California Gas Company	**$ 150**	$ 178	$ 169
San Diego Gas & Electric	**148**	91	141
Sempra Energy Trading	**62**	60	131
Sempra Energy Resources	**29**	36	(18)
All other	**(342)**	(219)	(210)
Total	**$ 47**	$ 146	$ 213
NET INCOME (LOSS)			
Southern California Gas Company	**$ 209**	$ 212	$ 207
San Diego Gas & Electric	**334**	203	177
Sempra Energy Trading	**98**	126	196
Sempra Energy Resources	**94**	60	(27)
All other	**(86)**	(10)	(35)
Total	**$ 649**	$ 591	$ 518

(Dollars in millions)	At December 31 or years ended December 31, 2003	2002	2001
ASSETS			
Southern California Gas Company	**$ 5,412**	$ 5,403	$ 4,986
San Diego Gas & Electric	**6,463**	6,285	6,542
Sempra Energy Trading	**5,923**	5,614	2,997
Sempra Energy Resources	**2,252**	1,347	577
All other	**2,780**	2,579	3,094
Intersegment receivables	**(821)**	(986)	(720)
Total	**$22,009**	$20,242	$17,476
CAPITAL EXPENDITURES			
Southern California Gas Company	**$ 318**	$ 331	$ 294
San Diego Gas & Electric	**444**	400	307
Sempra Energy Trading	**51**	21	45
Sempra Energy Resources	**142**	356	225
All other	**94**	106	197
Total	**$ 1,049**	$ 1,214	$ 1,068
GEOGRAPHIC INFORMATION			
Long-lived assets			
United States	**$10,380**	$ 9,548	$ 8,911
Latin America	**1,121**	1,062	836
Europe	**87**	18	10
Canada	**—**	3	24
Total	**$11,588**	$10,631	$ 9,781
Operating revenues			
United States	**$ 7,211**	$ 5,503	$ 7,169
Latin America	**315**	168	280
Europe	**323**	328	250
Canada	**10**	28	15
Asia	**28**	21	16
Total	**$ 7,887**	$ 6,048	$ 7,730

NOTE 17. QUARTERLY FINANCIAL DATA (UNAUDITED)

(Dollars in millions, except per share amounts)	Quarters ended March 31	June 30	September 30	December 31
2003				
Operating revenues	**$1,923**	**$1,840**	**$2,058**	**$2,066**
Operating expenses	**1,708**	**1,637**	**1,751**	**1,852**
Operating income	**$ 215**	**$ 203**	**$ 307**	**$ 214**
Income before cumulative effect of changes in accounting principles	**$ 117**	**$ 116**	**$ 211**	**$ 251**
Net income	**$ 88**	**$ 116**	**$ 211**	**$ 234**
Average common shares outstanding (diluted)	**207.8**	**210.2**	**212.3**	**227.2**
Income per common share before cumulative effect of changes in accounting principles (diluted)	**$ 0.56**	**$ 0.55**	**$ 1.00**	**$ 1.11**
Net income per common share (diluted)	**$ 0.42**	**$ 0.55**	**$ 1.00**	**$ 1.03**
2002				
Operating revenues	$1,475	$1,488	$1,385	$1,700
Operating expenses	1,224	1,260	1,075	1,502
Operating income	$ 251	$ 228	$ 310	$ 198
Income before extraordinary item	$ 146	$ 145	$ 150	$ 134
Net income	$ 146	$ 147	$ 150	$ 148
Average common shares outstanding (diluted)	206.4	207.1	205.4	205.6
Income per common share before extraordinary item (diluted)	$ 0.71	$ 0.70	$ 0.73	$ 0.65
Net income per common share (diluted)	$ 0.71	$ 0.71	$ 0.73	$ 0.72

Reclassifications have been made to certain of the amounts since they were presented in the Quarterly Reports on Form 10-Q.

QUARTERLY COMMON STOCK DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2003				
Market price				
High	**$26.00**	**$29.40**	**$30.33**	**$30.90**
Low	**$22.25**	**$24.05**	**$27.31**	**$26.36**
2002				
Market price				
High	$25.92	$26.25	$24.11	$24.62
Low	$22.15	$21.52	$15.50	$16.70

Dividends declared were $0.25 in each quarter.

FORM 10-K

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

Sempra Energy

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