Sempra Energy®

FINANCIAL REPORT

2002

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 2000 through 2002, 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 Annual Report.

The company, headquartered in San Diego, California, is a Fortune 500 energy services company whose principal subsidiaries are San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas), collectively referred to as the California Utilities, and Sempra Energy Global Enterprises (Global), itself a holding company owning most of the company's other subsidiaries.

Business Combination

Sempra Energy was formed to serve as a holding company for Pacific Enterprises (PE), the parent corporation of SoCalGas, and Enova Corporation (Enova), the parent corporation of SDG&E, in a tax-free business combination that became effective on June 26, 1998.

The California Utilities

SDG&E provides service to 3.1 million consumers through 1.3 million electric meters in San Diego and southern Orange counties, and 789,000 natural gas meters in San Diego County. SDG&E's service area encompasses 4,100 square miles, covering 26 cities. SoCalGas is the nation's largest natural gas distribution utility and provides service to 18.9 million customers through 5.3 million meters. SoCalGas' service territory encompasses 23,000 square miles, from San Luis Obispo on the north to the Mexican border in the south, and 535 cities. Within that territory it does not provide retail service in the City of Long Beach or SDG&E's service territory in San Diego County but does provide wholesale service to the retail providers in these areas. Together, the two utilities serve more than 21 million customers through approximately 7 million gas and electric meters.

Sempra Energy Global Enterprises

Global's primary subsidiaries, headquartered in San Diego unless otherwise noted, are as follows:

Sempra Energy Trading (SET), headquartered in Stamford, Connecticut, is a trading company that markets and trades physical and financial commodity products, including natural gas, power, petroleum products and base metals. During 2002, SET completed acquisitions that add base metals trading and warehousing to its business. See further discussion under "Investments" below. SET has more than 2,100 customers worldwide, including most of the major oil, gas and power companies in North America, Europe and Asia.

Sempra Energy Resources (SER) acquires, develops and operates power plants for the competitive market. On October 31, 2002, SER acquired a coal-fired power plant from Texas-New Mexico Power

Company, as further discussed under “Capital Expenditures” below. SER’s other merchant power plants use state-of-the-art, combined-cycle power generation technology and clean-burning natural gas to generate electricity for the wholesale market and retail electric providers, such as utilities, marketers and large energy users. It currently has two merchant power plants in operation (aggregating 525 megawatt (mW)), three under construction (aggregating 2,135 mW), and seven (not all of which will be built) that are at or beyond the permitting stage (aggregating 4,750 mW). The following table lists the mW of each power plant currently in operation, under construction or under development:

Power Plant	Generating Capacity	Location
In operation:		
Twin Oaks Power	305	Bremond, TX
El Dorado (50% owned)	220	Boulder City, NV
Total mW	525	
Under construction:		
Mesquite Power	1,250	Arlington, AZ
Termoeléctrica De Mexicali	600	Mexicali, Baja California, Mexico
Elk Hills Power (50% owned)	285	Bakersfield, CA
Total mW	2,135	
Permitting Stage:		
Bonnet Carre’	1,200	La Place, LA
Cedar Power	600	Dayton, TX
MC Energy	600	Dobbin, TX
Copper Mountain Power	600	Boulder City, NV
Eastalco	600	Frederick, MD
South Shore Power	600	Lake Township, MI
Palomar	550	Escondido, CA
Total mW	4,750	
Total mW	7,410	

Sempra Energy International (SEI) develops, operates and owns energy projects in international markets. SEI currently is involved in joint or solo ventures that provide natural gas or electricity to more than 2.7 million customers in Argentina, Chile, Mexico, Peru and the United States.

Sempra Energy Solutions (SES) sells energy commodities and provides an integrated mix of energy services, including facility management, supply and price-risk management, energy efficiency, energy asset management, performance contracting, and infrastructure ownership to assist commercial and industrial businesses in the changing energy environment.

Other

Sempra Energy Financial (SEF) invests in limited partnerships which own 1,300 affordable-housing properties throughout the United States, including Puerto Rico and the Virgin Islands. It also holds an interest in a limited partnership that produces synthetic fuel from coal.

Through other subsidiaries, the company is involved in other energy-related products and services.

RESULTS OF OPERATIONS

Overall Operations

Operating Income—2002 Compared to 2001

California Utility Revenues and Cost of Sales. 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. For the fourth quarter, natural gas revenues increased to $968 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. These changes were primarily attributable to changes in natural gas prices, as discussed below in “California Utility Operations.”

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. For the fourth quarter, electric revenues increased to $312 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. These changes were mainly due to the effect of the California Department of Water and Resource’s (DWR’s) purchasing the net short position of SDG&E, and changes in electric commodity costs and operating costs, as discussed in “California Utility Operations.”

Other Operating Revenues. Other operating revenues, which consist primarily of revenues from Global, decreased to $1.5 billion in 2002 from $1.7 billion in 2001. This decrease was primarily due to lower revenues from SET and SEI, partially offset by an increase in SER’s sales to the DWR. For the fourth quarter of 2002, other operating revenues increased to $408 million in 2002 from $242 million in 2001, due primarily to increases at SET and SER. See further discussion in “Sempra Energy Global Enterprises” below.

Other Cost of Sales. Other cost of sales, which consists primarily of cost of sales at Global, decreased to $709 million in 2002 from $873 million in 2001 primarily due to the lower operating revenues as noted above for SET and SEI, offset by increased costs associated with SER’s contract with the DWR as discussed below in “Sempra Energy Resources.” For the fourth quarter, other cost of sales increased to $206 million in 2002 from $174 million in 2001 due primarily to increased operating revenues at SET and SER. See “Sempra Energy Global Enterprises” below for further discussion of the change in other cost of sales.

Other Operating Expenses. Other operating expenses, primarily those of the California Utilities, increased to $1.9 billion in 2002 from $1.8 billion in 2001. The increase is due primarily to increased operating costs at the California Utilities and at SET. See further discussion below in “California Utility Operations” and “Sempra Energy Global Enterprises.” Additionally, in 2001, there was a $30 million pre-tax charge for the surrender of a natural gas distribution franchise in Nova Scotia, offset by a $33 million pre-tax gain on the sale of a subsidiary, Energy America.

Operating Income—2001 Compared to 2000

California Utility Revenues and Cost of Sales. Natural gas revenues increased to $4.4 billion in 2001 from $3.3 billion in 2000, and the cost of natural gas distributed increased to $2.5 billion in 2001 from $1.6 billion in 2000, primarily as the result of higher average costs and higher natural gas volumes in 2001. For the fourth quarter, natural gas revenues decreased to $773 million in 2001 from $969 million in 2000, and the cost of natural gas distributed decreased to $319 million in 2001 from $511 million in 2000. These decreases were attributable to the overall decrease in natural gas costs during the fourth quarter of 2001.

Electric revenues decreased to $1.7 billion in 2001 from $2.2 billion in 2000, and the cost of electric fuel and purchased power decreased to $0.8 billion in 2001 from $1.3 billion in 2000. For the fourth quarter, electric revenues decreased to $284 million in 2001 from $717 million in 2000, and the cost of electric fuel and purchased power decreased to $87 million in 2001 from $485 million in 2000. These decreases were attributable to the DWR's purchasing SDG&E's net short position for most of 2001, as compared to higher electric commodity costs paid directly by SDG&E in 2000. See additional discussion below in "California Utility Operations."

Other Operating Revenues. Other operating revenues increased to $1.7 billion in 2001 from $1.3 billion in 2000, primarily due to higher revenues from SET. For the fourth quarter of 2001, other operating revenues decreased to $242 million from $481 million in 2000 primarily due to lower revenues from SET, resulting from the decreased volatility in energy commodity markets in the fourth quarter of 2001. See additional discussion below in "Sempra Energy Global Enterprises."

Other Cost of Sales. Other cost of sales increased to $873 million in 2001 from $648 million in 2000, as discussed below in "Sempra Energy Global Enterprises."

Other Operating Expenses. Other operating expenses increased to $1.8 billion in 2001 from $1.6 billion in 2000, as discussed below in "California Utility Operations" and "Sempra Global Enterprises."

Other Income

Other income, which primarily consists of interest income from short-term investments, equity earnings from unconsolidated subsidiaries and interest on regulatory balancing accounts, was $57 million, $86 million and $127 million in 2002, 2001 and 2000, respectively. The decrease in 2002 was primarily due to lower interest income from short-term investments and lower equity earnings from international investments, partially offset by increased earnings from SER's investment in the El Dorado power plant, as well as $22 million (pretax) in business interruption insurance proceeds related to outages at SER's El Dorado plant during 2001. The decrease in 2001 was primarily due to lower earnings from the El Dorado power plant and the 2000 gain on the sale of SoCalGas' minority investment in Plug Power, partially offset by higher interest income 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 $16 million, $3 million and $42 million for 2002, 2001, and 2000, respectively. The increase in 2002 was due primarily to lower net regulatory interest expense. The decrease in 2001 from 2000 was due primarily to decreased equity earnings from unconsolidated subsidiaries.

Interest Expense

Interest expense was $294 million, $323 million and $286 million in 2002, 2001 and 2000, respectively. 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. The increase in 2001 was primarily due to interest expense incurred on long-term debt issued in December of 2000 and June of 2001, and on higher short-term commercial paper borrowings in 2001.

Interest expense for the fourth quarter was $70 million, $63 million and $70 million in 2002, 2001 and 2000, respectively. 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. The decrease in 2001 was due to lower debt balances and interest rates.

Income Taxes

Income tax expense was $146 million, $213 million and $270 million in 2002, 2001 and 2000, respectively. The effective income tax rates were 20.2 percent, 29.1 percent and 38.6 percent, respectively. The decreases in income tax expense and the effective rate for 2002 compared to 2001 were primarily due to the favorable resolution of income-tax issues at SDG&E in the second quarter of 2002 and increased income tax credits from synthetic fuel investments in 2002. The decreases in income tax expense and in the effective tax rate for 2001 compared to 2000 were primarily due to the favorable settlement of various tax issues and higher income tax credits, partially offset by the fact that any income tax benefits from certain losses outside the United States, primarily related to the Nova Scotia franchise surrender noted above, were not yet recordable in 2001.

Income tax expense for the fourth quarter was $3 million in 2002, compared to a benefit of $40 million in 2001 and expense of $103 million in 2000. The increase in 2002 was due primarily to increased income before taxes, as well as the resolution in 2001 of prior-year tax issues. The decrease in 2001 compared to 2000 was due to the 2001 prior-year tax resolution, and lower income before taxes in the fourth quarter of 2001. 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.

Net Income

Net income was $591 million, or $2.87 per diluted share of common stock, in 2002, compared to $518 million, or $2.52 per diluted share of common stock in 2001, and $429 million, or $2.06 per diluted share of common stock in 2000. Net income in 2002 includes an extraordinary item of $16 million ($0.08 per diluted share of common stock) net of tax, related to SET's acquisitions in 2002. ($2 million of the after-tax gain was recorded in the quarter ended June 30, 2002, and $14 million in the quarter ended December 31, 2002.) Excluding the effects of the extraordinary item, the increase in net income in 2002 was primarily due to improved results at SER, lower interest expense, the 2001 after-tax charge of $25 million for the surrender of the Nova Scotia natural gas distribution franchise and the effects of the income-tax matters referred to above, partially offset by lower income in 2002 from SET and the $20 million after-tax gain on sale of Energy America in 2001. The increase in 2001 compared to 2000 was primarily due to higher earnings from SET, as a result of higher volatility in the energy markets during the first half of 2001 and a substantial increase in trading volumes. Also contributing to the increase was the gain on the sale of Energy America, the favorable settlement of income tax issues and the effect in 2000 of a $30 million after-tax charge at SDG&E for regulatory issues. These factors were partially offset by the surrender of the Nova Scotia natural gas distribution franchise, and lower income from SER and SEI. See additional discussion in "California Utility Operations", "Sempra Energy Trading" and "Sempra Energy International" below.

Net income for the fourth quarter was $148 million, or $0.72 per diluted share of common stock in 2002, compared with $107 million, or $0.52 per diluted share of common stock in 2001, and $95 million, or $0.47 per diluted share of common stock in 2000. Net income for the fourth quarter of 2002 includes the extraordinary item related to SET's acquisitions that increased net income by $14 million ($0.07 per diluted share of common stock). Excluding the effects of the extraordinary item, the increase in quarterly earnings in 2002 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. The increase in quarterly earnings for 2001 compared to 2000 was primarily attributable to the favorable settlement of various income tax issues, partially offset by lower prices and reduced volatility in the energy markets, and development costs of new power plants.

Book value per share was $13.79, $13.16 and $12.35, at December 31, 2002, 2001 and 2000, respectively. The increases in 2002 and 2001 were primarily the result of net income exceeding the sum of dividends and the foreign currency translation losses related to the Argentine peso (See Note 1 of the notes to Consolidated Financial Statements).

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 regulated primarily by the California Public Utilities Commission (CPUC). It is the responsibility of the CPUC to regulate investor-owned utilities (IOUs) in a manner that serves the best interests of their customers while providing the IOUs the opportunity to earn a reasonable return on investment.

In 1996, California enacted legislation restructuring California's electric industry. The legislation and related decisions of the CPUC were intended to stimulate competition and reduce electric rates. As part of the framework for a competitive electric-generation market, the legislation established the California Power Exchange (PX) and the Independent System Operator (ISO). The PX served as a wholesale power pool and the ISO scheduled power transactions and access to the electric transmission system. Supply/demand imbalances and a number of other factors resulted in abnormally high electric commodity costs beginning in mid-2000 and continuing into 2001. Due to subsequent industry restructuring developments, the PX suspended its trading operations in January 2001. As a result of the passage of Assembly Bill (AB) X1 in February 2001, the DWR began to purchase power from generators and marketers to supply a portion of the power requirements of the state's population that is served by IOUs. Through December 31, 2002, the DWR was purchasing SDG&E's full net short position (the power needed by SDG&E's customers other than that provided by SDG&E's nuclear generating facilities or its previously existing purchased power contracts). 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.

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. In December 2001, the CPUC issued a decision related to natural gas industry restructuring, adopting several provisions that the California Utilities believe will make natural gas service more reliable, more efficient and better tailored to the desires of customers. The CPUC anticipated implementation during 2002; however, implementation has been delayed.

In connection with restructuring of the electric and natural gas industries, the California Utilities received approval from the CPUC for Performance-Based Ratemaking (PBR). Under PBR, income potential is tied to achieving or exceeding specific performance and productivity measures, such as demand side management and customer growth, rather than solely to expanding utility plant.

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

The tables below summarize the California Utilities' natural gas and electric volumes and revenues by customer class for the years ended December 31, 2002, 2001 and 2000.

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

	Natural Gas Sales		Transportation & Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
2002:						
Residential	**289**	**$2,089**	**2**	**$ 8**	**291**	**$2,097**
Commercial and industrial	**117**	**635**	**294**	**183**	**411**	**818**
Electric generation plants	**—**	**—**	**264**	**51**	**264**	**51**
Wholesale	**—**	**—**	**16**	**4**	**16**	**4**
	406	**$2,724**	**576**	**$246**	**982**	**2,970**
Balancing accounts and other						**285**
Total						**$3,255**
2001:						
Residential	297	$2,797	2	$ 6	299	$2,803
Commercial and industrial	113	903	262	174	375	1,077
Electric generation plants	—	—	417	104	417	104
Wholesale	—	—	40	10	40	10
	410	$3,700	721	$294	1,131	3,994
Balancing accounts and other						377
Total						$4,371
2000:						
Residential	284	$2,446	3	$ 13	287	$2,459
Commercial and industrial	107	760	339	225	446	985
Electric generation plants	—	—	373	130	373	130
Wholesale	—	—	25	18	25	18
	391	$3,206	740	$386	1,131	3,592
Balancing accounts and other						(287)
Total						$3,305

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

	2002		2001		2000	
	Volumes	**Revenue**	Volumes	Revenue	Volumes	Revenue
Residential	**6,266**	**$ 649**	6,011	$ 775	6,304	$ 730
Commercial	**6,053**	**633**	6,107	753	6,123	747
Industrial	**1,883**	**160**	2,792	325	2,614	310
Direct access	**3,448**	**117**	2,464	84	3,308	99
Street and highway lighting	**88**	**9**	89	10	74	7
Off-system sales	**5**	**—**	413	88	899	59
	17,743	**1,568**	17,876	2,035	19,322	1,952
Balancing and other		**(306)**		(359)		232
Total	**17,743**	**$1,262**	17,876	$1,676	19,322	$2,184

Although commodity-related revenues from the DWR's purchasing of SDG&E's net short position are not included in revenue, the associated volumes and distribution revenue are included herein.

California Utility Operations—2002 Compared to 2001

Natural Gas Revenue and Cost of Gas Distributed. 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 revenue is primarily due to lower natural gas prices and decreased transportation for electric generation plants and the loss of approximately 100 million cubic feet per day in load on the San Diego system when the North Baja pipeline began service in September 2002. The decrease in cost of natural gas distributed was primarily due to lower average natural gas commodity prices. For the fourth quarter, natural gas revenues increased to $968 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.

Under the current regulatory framework, changes in core-market natural gas prices (natural gas purchased for customers that are primarily residential and small commercial and industrial customers, without alternative fuel capability) or consumption levels do not affect net income, since core customer rates generally recover the actual cost of natural gas on a substantially concurrent basis and consumption levels are fully balanced. 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. See further discussion in Notes 1 and 14 of the notes to Consolidated Financial Statements.

Electric Revenue and Cost of Electric Fuel and Purchased Power. 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 purchases of SDG&E's net short position for a full year in 2002, the effect of lower electric commodity costs and decreased off-system sales. Under the current regulatory framework, changes in commodity costs normally do not affect net income. The commodity costs associated with the DWR's purchases and the corresponding sale to SDG&E's customers are not included in the Statements of Consolidated Income as SDG&E was merely transmitting the electricity from the DWR to the customers. Similarly, in 2001, PX/ISO power revenues have been netted against purchased-power expense to avoid double counting as SDG&E sold power to the PX/ISO and then purchased power therefrom.

For the fourth quarter, electric revenues increased to $312 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 the San Onofre Nuclear Generating Station (SONGS).

Other Operating Expenses. Other operating expenses increased to $1.4 billion in 2002 from $1.3 billion in 2001. For the fourth quarter, other operating expenses increased to $445 million in 2002 from $366 million in 2001. The increases were primarily due to higher labor and employee benefits costs and increases in other operating costs, including operating costs that are associated with SDG&E's nuclear generating facilities and balancing account costs at SoCalGas.

California Utility Operations—2001 Compared to 2000

Natural Gas Revenue and Cost of Gas Distributed. Natural gas revenues increased to $4.4 billion in 2001 from $3.3 billion in 2000, and the cost of natural gas distributed increased to $2.5 billion in 2001 from $1.6 billion in 2000. These increases were due to higher average natural gas commodity prices and higher volumes of natural gas sales in 2001. For the fourth quarter, natural gas revenues decreased to $773 million in 2001 from $969 million in 2000, and the cost of natural gas distributed decreased to $319 million in 2001 from $511 million in 2000. These decreases were attributable to the lower natural gas costs in the fourth quarter of 2001.

Electric Revenue and Cost of Electric Fuel and Purchased Power. Electric revenues decreased to $1.7 billion in 2001 from $2.2 billion in 2000, and the cost of electric fuel and purchased power decreased to $0.8 billion in 2001 from $1.3 billion in 2000. For the fourth quarter, electric revenues decreased to $284 million in 2001 from $717 million in 2000, and the cost of electric fuel and purchased power decreased to $87 million in 2001 from $485 million in 2000. These decreases were primarily due to the DWR's purchasing of SDG&E's net short position starting in February 2001, offset by a $30 million after-tax charge for regulatory issues in 2000 related to a potential regulatory disallowance for the acquisition of wholesale power in the newly deregulated California market.

Other Operating Expenses. Other operating expenses increased to $1.3 billion in 2001 from $1.1 billion in 2000. For the fourth quarter, other operating expenses increased to $366 million in 2001 from $338 million in 2000. These increases were primarily due to increased wages and employee benefits costs, as well as increases in the operating costs that are associated with balancing accounts and, therefore, do not affect net income.

Sempra Energy Global Enterprises

The following table is a summary of Global's operating revenues, cost of sales, operating expenses and operating income (loss) by business unit.

	For the Years ended December 31		
Dollars in millions	**2002**	2001	2000
OPERATING REVENUES			
Sempra Energy Trading	**$ 821**	$1,047	$ 822
Sempra Energy Resources	**349**	178	11
Sempra Energy International	**176**	289	159
Sempra Energy Solutions	**177**	180	103
Other	**2**	59	243
Total	**$1,525**	$1,753	$1,338
COST OF SALES			
Sempra Energy Trading	**$ 293**	$ 320	$ 266
Sempra Energy Resources	**218**	185	2
Sempra Energy International	**148**	257	141
Sempra Energy Solutions	**56**	92	57
Other	**—**	26	211
Total	**$ 715**	$ 880	$ 677
OPERATING EXPENSES			
Sempra Energy Trading	**$ 304**	$ 370	$ 269
Sempra Energy Resources	**44**	21	19
Sempra Energy International	**49**	70	40
Sempra Energy Solutions	**66**	68	51
Other	**20**	32	42
Total	**$ 483**	$ 561	$ 421
OPERATING INCOME (LOSS)			
Sempra Energy Trading	**$ 203**	$ 330	$ 256
Sempra Energy Resources	**84**	(29)	(13)
Sempra Energy International	**(34)**	(51)	(30)
Sempra Energy Solutions	**43**	4	(18)
Other	**(20)**	(3)	(21)
Total	**$ 276**	$ 251	$ 174

Operating income (loss) is also net of depreciation and amortization expense, and taxes other than income taxes. It does not include foreign-currency gains, interest income, equity earnings from unconsolidated subsidiaries and other items that are included in "other income—net" in the Statements of Consolidated Income.

Revenues and cost of sales for the other business units of Global were higher in 2000 due to the sale of Energy America in January 2001.

Global—2002 Compared to 2001

Operating Revenues. Operating revenues for Global decreased to $1.5 billion in 2002 from $1.8 billion in 2001. This decrease was primarily due to lower revenues from SET as a result of decreased volatility in energy commodity markets and decreased energy commodity prices during 2002, partially offset by increased revenues from new acquisitions. Additionally, SEI experienced lower revenues as a result of decreased prices for power from its Rosarito pipeline. 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 recommenced in April 2002 at favorable contract rates under its long-term contract. For the fourth quarter of 2002, other operating revenues increased to $416 million from $294 million in 2001. The increase was primarily due to increased revenues at SET as a result of higher volatility in energy commodity markets in the fourth quarter of 2002, as well as the increased revenues at SER.

Cost of Sales. Other cost of sales decreased to $715 million in 2002 from $880 million in 2001. This decrease was primarily due to the lower operating revenues discussed above for SET and SEI, and lower costs for SES related to project deliveries, offset by increased costs associated with SER's contract with the DWR. For the fourth quarter, other cost of sales increased to $207 million in 2002 from $180 million in 2001, primarily related to the increased operating revenues at SET and SER.

Operating Expenses. Operating expenses for Global decreased to $483 million in 2002 from $561 million in 2001. Operating expenses decreased due primarily to decreased labor costs associated with the lower SET and SEI revenues discussed above. For the fourth quarter, operating expenses increased to $138 million in 2002 from $109 million in 2001, due primarily to increased costs associated with the higher fourth quarter revenues at SET and SER.

Global—2001 Compared to 2000

Operating Revenues. Operating revenues for Global increased to $1.8 billion in 2001 from $1.3 billion in 2000. This increase was primarily due to higher revenues from SET as a result of increased volatility and trading volumes in energy commodity markets during the first half of 2001, and due to SER's contracted sale of electricity to the DWR at a discounted price in 2001. This was partially offset by the sale of Energy America in the first quarter of 2001. For the fourth quarter, other operating revenues decreased in 2001 from 2000 primarily due to lower revenues from SET as the result of the decreased volatility in energy commodity markets in the fourth quarter of 2001, as well as the sale of Energy America.

Cost of Sales. Other cost of sales increased to $880 million in 2001 from $677 million in 2000, primarily due to the increase in operating revenues for SET noted above and SER's costs associated with the DWR contract. For the fourth quarter, other cost of sales decreased in 2001 from 2000, primarily due to the decrease in the volatility of energy commodity markets previously mentioned.

Operating Expenses. Operating expenses increased to $561 million in 2001 from $421 million in 2000 due primarily to increased labor costs for SET's operations. For the fourth quarter, operating expense decreased in 2001 from 2000, primarily due to lower volatility of energy commodity markets.

Net Income by Business Unit

Dollars in millions	For the years ended December 31 2002	2001	2000
California Utilities			
Southern California Gas Company	**$212**	$207	$ 206
San Diego Gas & Electric	**203**	177	145
Total Utilities	**415**	384	351
Global Enterprises			
Sempra Energy Trading	**126**	196	155
Sempra Energy Resources	**60**	(27)	29
Sempra Energy International	**26**	25	33
Sempra Energy Solutions	**21**	1	(14)
Interest and other	**(38)**	(22)	(28)
Total Global Enterprises	**195**	173	175
Sempra Energy Financial	**36**	28	28
Parent and other	**(55)**	(67)	(125)
Consolidated	**$591**	$518	$ 429

Southern California Gas Company

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

Net income for SoCalGas increased to $207 million in 2001 from $206 million in 2000 primarily due to higher natural gas volumes in 2001, offset by the gain on sale of SoCalGas' minority investment in Plug Power during 2000. Net income for the fourth quarter of 2001 decreased compared to the fourth quarter of 2000, primarily due to the sale of the investment in Plug Power.

San Diego Gas & Electric

Net income increased to $203 million in 2002 from $177 million in 2001. The increase was primarily due to a $25 million after-tax benefit from the favorable resolution of prior year income-tax issues in the second quarter of 2002 and lower interest expense in 2002, partially offset by the 2001 gain on sale of SDG&E's Blythe property and lower interest income in 2002. 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 and electric distribution and transmission revenues and income tax adjustments in 2002, partially offset by the 2001 Blythe gain.

Net income increased to $177 million in 2001 from $145 million in 2000. The increase was primarily due to the Blythe gain, lower interest expense and a $30 million after-tax charge in 2000 related to a potential regulatory disallowance. These increases were partially offset by lower interest income from affiliates. Net income increased to $45 million for the fourth quarter of 2001, compared to $38 million for the corresponding period in 2000 as a result of the Blythe property sale.

Sempra Energy Trading

SET recorded net income of $126 million in 2002, compared to net income of $196 million and $155 million in 2001 and 2000, respectively. The decrease in net income in 2002 compared to 2001 was primarily due to increased 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. The increase in net income for 2001 compared to 2000 was primarily due to high volatility in energy commodity markets during the first half of 2001 and an increase in trading volumes, partially offset by reduced profitability in Europe.

A summary of SET's net unrealized revenues for trading activities for the years ended December 31, 2002 and 2001 (dollars in millions) follows:

	2002	2001
Balance at beginning of year	**$ 405**	$ (72)
Additions	**442**	1,333
Realized	**(667)**	(856)
Balance at end of year	**$ 180**	$ 405

The estimated fair values for SET's net unrealized trading assets as of December 31, 2002, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	2003	2004 and 2005	2006 and 2007	Thereafter	Total Fair Value
Prices actively quoted	$ 175	$100	$12	$—	$ 287
Prices provided by other external sources	(6)	(3)	(4)	21	8
Prices based on models and other valuation methods	4	9	11	2	26
Over-the-counter revenue (1)	173	106	19	23	321
Exchange contracts (2)	(166)	24	1	—	(141)
Total	$ 7	$130	$20	$23	$ 180

(1) The present value of unrealized revenue to be received or (paid) from outstanding OTC contracts.
(2) Cash (paid) or received associated with open Exchange contracts.

Sempra Energy Resources

SER recorded net income of $60 million in 2002, compared to a net loss of $27 million in 2001 and net income of $29 million in 2000. The increase in results for 2002 was primarily due to SER's sales to the DWR that recommenced in April 2002 at contract rates under its long-term contract, compared to 2001 sales which were at below cost, and the recovery in 2002 of business interruption insurance related to outages 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 in 2001.

Sempra Energy International

Net income for SEI in 2002 was $26 million, compared to $25 million and $33 million for 2001 and 2000, respectively. The increase in net income for 2002 was primarily due to the after-tax charge of $25 million in 2001 following the surrender of Sempra Atlantic Gas' 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. The decrease in net income for 2001 was primarily due to the surrender of the natural gas franchise noted above, partially offset by increased earnings at the Latin American subsidiaries. Additional information concerning the company's international operations is provided in Note 3 of the notes to Consolidated Financial Statements.

Sempra Energy Solutions

SES recorded net income of $21 million in 2002, compared to net income of $1 million in 2001 and a net loss of $14 million in 2000. The increase in net income from 2001 to 2002 is primarily due to increased commodity sales. The loss for 2000 is primarily attributable to start-up costs, which continued in 2001 but which were more than offset by increased commodity sales in 2001.

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 for trading activities for the years ended December 31, 2002 and 2001 (dollars in millions) follows:

	2002	2001
Balance at beginning of year	**$ 55**	$ 1
Additions	**90**	62
Realized	**(55)**	(8)
Balance at end of year	**$ 90**	$55

The estimated fair values for SES' net unrealized trading assets as of December 31, 2002, and the periods during which unrealized revenues are expected to be realized, are (dollars in millions):

Source of fair value	2003	2004 and 2005	2006 and 2007	Thereafter	Total Fair Value
Exchange contracts	$ 1	$—	$ —	$ —	$ 1
Prices actively quoted	48	32	8	1	89
Total	$49	$32	$ 8	$ 1	$90

Sempra Energy Financial

SEF invests as a limited partner in affordable-housing properties. SEF's portfolio includes 1,300 properties throughout the United States, including Puerto Rico and the Virgin Islands. These investments are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also has an investment in a limited partnership which produces synthetic fuel from coal. SEF recorded net income of $36 million in 2002 and $28 million in each of 2001 and 2000. The increase in 2002 was due primarily to increased tax benefits resulting from increased synthetic fuel production. Whether SEF will invest in additional properties will depend on Sempra Energy's income tax position.

Parent and Other

Net losses for Parent and Other were $55 million, $67 million and $125 million in 2002, 2001 and 2000, respectively. The decrease in net losses in 2002 was attributable to the consolidating elimination of intercompany profits. During 2001, certain intercompany mark-to-market revenues recognized by subsidiaries were deferred in consolidation until the completion of the sales to the end customer. In 2002, most of these deferred revenues were no longer deferred. The decrease in net losses from 2000 to 2001 was due primarily to charges in 2000 relating to income tax and credit issues associated with pre-merger operations of subsidiaries that are no longer active.

CAPITAL RESOURCES AND LIQUIDITY

The company's California Utility operations are the major source of liquidity. Funding of other business units' capital expenditures is partly dependent on the California Utilities' paying sufficient dividends to Sempra Energy. Beginning in the third quarter of 2000 and continuing into the first quarter of 2001, SDG&E's liquidity and its ability to make funds available to Sempra Energy were adversely affected by the electric cost undercollections resulting from a temporary ceiling on electric rates legislatively imposed in response to high electric commodity costs. Growth in these undercollections ceased as a result of an agreement with the DWR, under which the DWR was obligated to purchase electricity for SDG&E's customers to fill SDG&E's full net short position consisting of the power and ancillary services required by SDG&E's customers that were not provided by SDG&E's nuclear generating facilities or its previously existing purchased-power contracts. The agreement with the DWR extended through December 31, 2002. Starting on January 1, 2003, SDG&E and other California IOUs resumed their electric commodity procurement function based on a CPUC decision issued in October 2002. In addition, AB 57 and implementing decisions by the CPUC provide for periodic adjustments to rates that would reflect the costs of power and are intended to ensure the timely recovery of any undercollections.

Another issue with potential implications to capital resources and liquidity is the ownership of certain power sale contracts. The company believes that all profits associated with the contracts properly are for the benefit of SDG&E shareholders rather than customers, whereas the CPUC asserted that all the profits should accrue to the benefit of customers. On December 19, 2002, in a 3-to-2 decision, the CPUC approved a proposed settlement that divides the profits from these contracts, $199 million for SDG&E customers and $173 million for SDG&E shareholders. Of the $199 million in profits allocated to customers, $175 million had already been credited to ratepayers in 2001. The remaining $24 million was applied as a balancing account transfer that reduced the AB 265 balancing account in December 2002. The profits allocated to customers reduce SDG&E's AB 265 undercollection, but do not adversely affect SDG&E's financial position, liquidity or results of operations. The term of a commissioner who voted to approve the settlement has expired, and a new commissioner has been appointed. On January 29, 2003, the CPUC's Office of Ratepayer Advocates, the City of San Diego and the Utility Consumers' Action Network, a consumer-advocacy group, filed requests for a CPUC rehearing of the decision. On February 13, 2003, the company filed its opposition to rehearing of the decision. Parties requesting a rehearing and parties to any rehearing may also appeal the CPUC's final decision to the California appellate courts.

For additional discussion, see "Factors Influencing Future Performance-Electric Industry Restructuring and Electric Rates" herein and Note 13 of the notes to Consolidated Financial Statements.

At December 31, 2002, the company had $455 million in cash and $2.25 billion in unused, committed lines of credit available. As of December 31, 2002, $600 million of the lines was supporting commercial paper and variable-rate debt. In addition, in February 2003, the company issued $400 million of senior unsecured notes with a 10-year term at a fixed interest coupon of 6 percent. The proceeds were used to repay short-term debt.

Management believes these amounts, cash flows from operations, and new security issuances will be adequate to finance capital expenditure requirements, shareholder dividends, any new business acquisitions or start-ups, and other commitments. If cash flows from operations were significantly reduced and/or the company was 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 adequately meet the needs of its operating, financing and investing activities.

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 significant dividends to Sempra Energy.

SET provides cash to or requires cash from Sempra Energy as the level of its net trading assets fluctuates with prices, volumes, margin requirements (which are substantially affected by credit ratings and price fluctuations) and the length of its various trading positions. Its status as a source or use of Sempra Energy cash also varies with its level of borrowing from its own sources. During 2002, SET's borrowings from the company varied from a low of $6 million to a high of $754 million, and were $418 million at December 31, 2002. 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" below.

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

SEI is expected to require funding from the company and/or external sources to continue the expansion of its existing natural gas distribution operations in Mexico and its planned development of liquefied natural gas (LNG) facilities.

SES is expected to require moderate amounts of cash in the near future as its commodity and energy services businesses continue to grow.

SEF is expected to continue to be a net provider of cash through reductions of consolidated income tax payments resulting from its investments in affordable housing and synthetic fuel.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $1.4 billion, $0.7 billion and $0.9 billion for 2002, 2001 and 2000, respectively. The increase in cash flows from operations in 2002 compared to 2001 was attributable to SDG&E's collection of a portion of prior purchased-power costs (the remaining balance of which decreased to $392 million at December 31, 2001 and $215 million at December 31, 2002 from a high in mid-2001 of $750 million), the refunds to large customers in 2001 resulting from AB 43X (which extended a temporary 6.5-cents rate cap to include SDG&E's large customers), 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. See further discussion on the 2001 impact of regulatory balancing accounts activity for the California Utilities below.

The decrease in cash flows from operating activities in 2001 compared to 2000 was primarily attributable to the decrease in accounts payable due to lower natural gas costs in 2001 compared to 2000 and the result of balancing account activity at SoCalGas. This included returns of prior overcollections and the temporary effects of higher-than-expected costs of natural gas and public-purpose programs and lower-than-expected sales volumes. The decrease was partially offset by lower accounts receivable balances at the end of 2001. The SoCalGas activity was further offset by the increase in overcollected balancing accounts at SDG&E and the fact that 2001 included refunds by SDG&E to large customers resulting from AB 43X. In 2000, SDG&E paid higher customer refunds for surplus rate-reduction-bond proceeds.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $1.7 billion, $1.0 billion and $0.9 billion for 2002, 2001 and 2000, respectively. 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.

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

Capital Expenditures for Property, Plant and Equipment

Capital expenditures increased to $1.2 billion in 2002, compared with $1.1 billion in 2001. The increase was due to higher expenditures by SER and the California Utilities in 2002. Capital expenditures in 2001 were $300 million higher than in 2000 primarily due to power plant construction costs at SER. See further discussion below.

The California Utilities

Capital expenditures for property, plant, and equipment by the California Utilities were $731 million in 2002 compared to $601 million in 2001 and $522 million in 2000. The increases in 2002 and 2001 were 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. The expansion of SoCalGas' pipeline capacity was completed in 2002.

Sempra Energy Resources

On October 31, 2002, SER purchased a 305-megawatt, coal-fired power plant (renamed Twin Oaks Power) from Texas-New Mexico Power Company for $120 million. SER has a five-year contract to sell substantially all of the output of the 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. See discussion below on SER's 2003 commitments for construction of its power plants.

In September 2001, ground was broken for the Mesquite Power Plant. Located near Phoenix, Arizona, the $690 million, 1,250-megawatt project will provide electricity to wholesale energy markets in the Southwest region. Commercial operations at 50-percent capacity are expected to commence in June 2003 and project completion is anticipated in January 2004. The project is being financed primarily via the synthetic lease agreement described in Note 15 of the notes to Consolidated Financial Statements. Construction expenditures as of December 31, 2002 were $558 million and SER has commitments of $50 million related to this project. Financing under the synthetic lease in excess of $280 million requires 103 percent collateralization through the purchase of U.S. Treasury obligations in similar amounts. During 2002, the company purchased $228 million of U.S. Treasury obligations as collateral, which is included in "Investments" on the Consolidated Balance Sheets.

In February 2001, the company announced plans to construct Termoelectrica de Mexicali, a $350 million, 600-megawatt power plant near Mexicali, Mexico. Fuel for the plant will be supplied via the pipeline from Arizona to Tijuana discussed below. It is anticipated that the electricity produced by the plant will be available for markets in California, Arizona and Mexico via a newly constructed 230,000-volt transmission line. Construction of the power plant began in the second half of 2001. During 2002 and as of December 31, 2002, $158 million and $308 million, respectively, have been invested in the project, which has begun testing and is scheduled for completion by mid-2003.

Sempra Energy International

In the third quarter of 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico, with a pipeline being built by PG&E Corporation that will connect 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 Termoelectrica de Mexicali power plant discussed above. Capacity on the pipeline is fully subscribed. Total capital expenditures of $124 million have been made by SEI through December 31, 2002.

SEI's Mexican subsidiaries Distribuidora de Gas Natural (DGN) de Mexicali, DGN de Chihuahua and DGN de La Laguna Durango built and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico, respectively. At December 31, 2002, SEI owned interests of 60, 95 and 100 percent in the projects, respectively. Through December 31, 2002, DGN de Mexicali, DGN de Chihuahua and DGN de La Laguna Durango have made capital expenditures of $23 million, $57 million and $32 million, respectively. Total capital expenditures for these subsidiaries in 2002 were $15 million. On February 7, 2003, SEI completed its purchase of the remaining interests in DGN de Mexicali, DGN de Chihuahua, Transportadora de Gas Natural, a supplier of natural gas to the Presidente Juarez power plant in Rosarito, Baja California, and other subsidiaries.

In October 2001, Sempra Energy announced plans to develop a major new LNG receiving terminal to bring natural gas supplies into northwestern Mexico and southern California. The plant, Energia Costa Azul, would be located on the Pacific Coast, north of Ensenada, Baja California, Mexico. SEI initially purchased a 300-acre site for the terminal for a purchase price of $19.7 million. Subsequently, it purchased additional land for the terminal for $2.6 million. As currently planned, the plant would have a send-out capacity of approximately 1 billion cubic feet per day of natural gas through a new 40-mile pipeline between the terminal and existing pipelines in the San Diego/Baja California border area. The project is currently estimated to cost $600 million and to commence commercial operations in 2007.

In 2000, SEI invested $159 million in two Argentine natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.).

Other

In February 2003, Sempra LNG Corp., a newly created subsidiary of Global, announced an agreement to acquire the proposed Hackberry, La., LNG project from a subsidiary of Dynegy, Inc. Sempra LNG Corp. initially will pay Dynegy $20 million, with additional payments contingent on the performance of the project. The project has received preliminary approval from the Federal Energy Regulatory Commission (FERC) and expects a final decision later this year. If the project is approved, Sempra LNG Corp. would build an LNG receiving facility capable of processing up to 1.5 billion cubic feet per day of natural gas. The total cost of the project is expected to be about $700 million. The project could begin commercial operations as early as 2007.

Investments

Investments and acquisition costs were $442 million, $111 million and $243 million for 2002, 2001 and 2000, respectively. The increase in 2002 was due to collateral requirements associated with the synthetic lease financing for the construction of the Mesquite Power Plant and SET's acquisition of new businesses. For discussion of the synthetic lease, see Note 15 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. 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. On April 26, 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 the Liverpool, England-based 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. All of these entities were part of the former MG Metals Group, which had been recently acquired by Enron. In January 2003, SET purchased from CMS Energy's marketing and trading unit a substantial portion of its wholesale natural gas trading book for $17 million.

Sempra Energy Resources

During 2002 and 2001, SER invested $39 million and $91 million, respectively, in the Elk Hills Power Project (Elk Hills), a $395 million, 570-megawatt power plant near Bakersfield, California, which is anticipated to be completed in May 2003. SER anticipates its share of the remaining construction costs will be $35 million. Elk Hills, an unconsolidated subsidiary, is being developed in a 50/50 joint venture with Occidental Energy Ventures Corporation (Occidental) and will supply electricity to California. Information concerning litigation with Occidental is provided in Note 15 of the notes to Consolidated Financial Statements.

Other

In August 2000, SES purchased its partner's 50-percent interests in Atlantic-Pacific Las Vegas and Atlantic-Pacific Glendale for a total of $40 million, thereby acquiring full ownership of these companies.

In September 2000, the company acquired for $8 million a significant minority interest in Atlantic Electric and Gas, a United Kingdom retail energy marketer.

See further discussion of investing activities, including the $223 million foreign currency exchange adjustment relating to Argentina, in Note 3 of the notes to Consolidated Financial Statements.

Future Construction Expenditures and Investments

The company expects to make capital expenditures of $1.3 billion in 2003, including $300 million which is not yet committed. Significant capital expenditures are expected to include $750 million for California utility plant improvements and $230 million for SER power plant construction and other capital projects. These expenditures are expected to be financed by operations and security issuances.

Over the next five years, the company expects to make capital expenditures of approximately $4 billion at the California Utilities and is committed to $350 million of capital expenditures at the other subsidiaries, including completion of the three power plants being constructed by SER. In addition, the company is evaluating an additional $2 billion of capital expenditures, which is not yet committed.

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 unprecedented number of existing power plants and other energy-related facilities that are in excess of market demand in certain regions of the country or 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's intention is to finance any sizeable expenditures so as to maintain the company's strong investment-grade ratings and capital structure. Smaller expenditures will be made by the use of existing liquidity.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash provided by financing activities totaled $138 million, $275 million and $192 million for 2002, 2001 and 2000, respectively.

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 new debt issuances in 2002.

Net cash provided by financing activities in 2001 was more than that provided in 2000 due to a $160 million loan obtained from an unconsolidated affiliate in 2001.

Long-Term and Short-Term Debt

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. The 4.80% first-mortgage bonds mature on October 1, 2012. The bonds are not subject to a sinking fund and are not redeemable prior to maturity except through a make-whole mechanism. Proceeds from the bond sale have become part of the company's general treasury funds to replenish amounts previously expended to refund and retire indebtedness and will be used for working capital and other general corporate purposes. 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 (to be determined by the then-prevailing market prices). The company used the net proceeds of the offering to repay a portion of its short-term debt, including debt used to finance the capital expenditure program for Global. In addition, SER drew down $300 million against a line of credit to finance construction projects and acquisitions.

Repayment of long-term debt of $479 million included repayments at maturity of $100 million of SoCalGas' 6.875% first-mortgage bonds and $28 million of SDG&E's 7.625% first-mortgage bonds, and the calling of $10 million of SDG&E's 8.5% first-mortgage bonds. Additionally, the company repaid $200 million of the $300 million borrowed under a line of credit in 2002 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.

On September 30, 2002, SoCalGas cancelled a fixed-to-variable interest-rate swap on $175 million of first-mortgage bonds. The $6 million gain on the transaction is being amortized over the life of the bonds, which mature in 2025.

On September 10, 2002, Global replaced its expiring $1.2 billion revolving line of credit with a $950 million syndicated line. The new revolving line of credit is guaranteed by Sempra Energy and its interest rate varies with market rates and credit ratings. It expires in September 2003, at which time outstanding borrowings may be converted to a one-year term loan. The agreement requires Sempra Energy to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent.

In May 2002, SDG&E and SoCalGas replaced their individual revolving lines of credit with a combined revolving credit agreement under which each utility may individually borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Each utility's revolving credit line expires on May 16, 2003, at which time it may convert its then outstanding borrowings to a one-year term loan, subject to having obtained any requisite regulatory approvals. Borrowings under the agreement, which are available for general corporate purposes including back-up support for commercial paper and variable-rate long-term debt, would bear interest at rates varying with market rates and the borrowing utility's credit rating. The agreement requires each utility to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 60 percent. The rights, obligations and covenants of each utility under the agreement are individual rather than joint with those of the other utility, and a default by one utility would not constitute a default by the other.

In 2001, the company issued $500 million in long-term debt, primarily for capital expenditures by the Global subsidiaries. The net short-term debt increase of $310 million in 2001 primarily represented borrowings through Global. Funds were used to finance construction costs of various power plant and pipeline projects in California, Arizona and Mexico. During 2001, $82 million of the Employee Stock Ownership (ESOP) debt and $25 million of variable-rate unsecured bonds were remarketed at 7.375 percent and 6.75 percent, respectively. In addition, SEI refinanced $160 million of its long-term notes through an Offering Memorandum of Chilquinta Energia Finance Co. LLC, which, like the company's other investments in Peru and Chile, is owned 50 percent by SEI and 50 percent by PSEG Global. Repayments on long-term debt in 2001 included $150 million of first-mortgage bonds, $66 million of rate-reduction bonds and $120 million of unsecured debt.

In 2000, the company issued $500 million of long-term notes and $200 million of mandatorily redeemable trust preferred securities to finance the repurchase of 36.1 million shares of its outstanding common stock. The company issued an additional $300 million of long-term notes during 2000 to repay a portion of its short-term debt. The net increase in short-term debt primarily represents borrowings through Global used to finance the construction of natural gas distribution systems by SEI and borrowings by SET to finance increased trading activities. Repayments on long-term debt in 2000 included $10 million of first-mortgage bonds, $66 million of rate-reduction bonds and $51 million of unsecured debt. In addition, in December 2000, $60 million of variable-rate industrial development bonds were put back by the holders and remarketed in February 2001 at a fixed interest rate of 7 percent.

In February 2003, the company issued $400 million of senior unsecured notes with a 10-year term at a fixed interest rate of 6 percent. The proceeds were used to replace short-term debt.

Capital Stock Transactions

In April and May of 2002, the company publicly offered and sold $600 million of "Equity Units." Each unit consists of $25 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 determined by the then-prevailing market price. The company used the net proceeds of the offering primarily to repay a portion of its short-term debt, including the repayment of $200 million borrowed by SER in April 2002 and other debt used to finance the capital expenditure program for Global.

As noted above, in February 2000, the company completed a self-tender offer, purchasing 36.1 million shares of its outstanding common stock at $20 per share. In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase shares of common stock from time to time in the open market or in privately negotiated transactions. Under this authorization, the company acquired 162,400 shares in July 2000, 60,000 shares in November 2001 and 674,400 shares in July 2002.

Dividends

Dividends paid on common stock amounted to $205 million in 2002, $203 million in 2001 and $244 million in 2000. The lower dividends in 2001 and 2002 were due to the company's repurchase of 36.1 million shares of its outstanding common stock in 2000.

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, 2002, SDG&E and SoCalGas each could have provided $250 million to Sempra Energy (combined loans and dividends). At December 31, 2002, SDG&E and SoCalGas had loans to Sempra Energy of $250 million and $86 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, 2002 was $7.8 billion. The debt-to-capitalization ratio was 59 percent at December 31, 2002. Significant changes in capitalization during 2002 included long-term borrowings and dividends.

Cash and Cash Equivalents

At December 31, 2002, the company had $455 million of cash and $2.35 billion of committed lines of credit, $100 million of which was borrowed. As of December 31, 2002, $600 million of the lines was supporting commercial paper and variable-rate debt. Management believes these amounts and cash flows from operations and new security issuances will be adequate to finance capital expenditures, shareholder dividends, any new business acquisitions or start-ups, and other commitments.

Other information concerning the credit lines and related matters is provided in Notes 4, 5 and 10 of the notes to Consolidated Financial Statements.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2002 (dollars in millions). 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.

	By Period				
Description	2003	2004 and 2005	2006 and 2007	Thereafter	Total
Short-term debt	$ 570	$ —	$ —	$ —	$ 570
Long-term debt	281	1,145	783	2,159	4,368
Mandatorily redeemable trust preferred securities	—	—	—	200	200
Preferred stock of subsidiaries subject to mandatory redemption	—	3	3	19	25
Operating leases	94	205	208	1,385	1,892
Purchased power contracts	257	455	437	2,285	3,434
Natural gas contracts	897	424	135	157	1,613
Construction commitments	162	7	—	95	264
Twin Oaks coal supply	28	54	46	310	438
SONGS decommissioning	20	22	9	258	309
Environmental commitments	16	31	11	—	58
Totals	$2,325	$2,346	$1,632	$6,868	$13,171

Credit Ratings

As of January 31, 2003, credit ratings for Sempra Energy and its primary subsidiaries were as follows:

	S&P	Moody's	Fitch
SEMPRA ENERGY			
Unsecured Debt	A-	Baa1	A
Commercial Paper	A-2	P-2	F1
Trust Preferred Securities	BBB	Baa2	A-
SDG&E			
Secured Debt	A+	A1	AA
Unsecured Debt	A	A2	AA-
Preferred Stock	A-	Baa1	A+
Commercial Paper	A-1	P-1	F1+
SOCALGAS			
Secured Debt	A+	A1	AA
Unsecured Debt	A	A2	AA-
Preferred Stock	A-	Baa1	A+
Commercial Paper	A-1	P-1	F1+
PACIFIC ENTERPRISES			
Preferred Stock	BBB+	—	A+
GLOBAL			
Unsecured Debt guaranteed by Sempra Energy	—	Baa1	—
Sempra Guaranteed Commercial Paper	A-2	P-2	F1

As of January 31, 2003, the company has a stable outlook rating from all three credit rating agencies.

FACTORS INFLUENCING FUTURE PERFORMANCE

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

CALIFORNIA UTILITIES

Electric Industry Restructuring and Electric Rates

Supply/demand imbalances and a number of other factors resulted in abnormally high electric-commodity costs beginning in mid-2000 and continuing into 2001. This caused SDG&E's customer bills to be substantially higher than normal. In response, legislation enacted in September 2000 imposed a ceiling of 6.5 cents/kilowatt hour (kWh) on the cost of electricity that SDG&E could pass on to its small-usage customers on a current basis. SDG&E accumulated the amount that it paid for electricity in excess of the ceiling rate in an interest-bearing balancing account. This undercollection amounted to $447 million, $392 million and $215 million at December 31, 2000, 2001 and 2002, respectively.

In February 2001, the DWR began to purchase power from generators and marketers to supply a portion of the state's power requirements that is served by IOUs. From early 2001 to December 31, 2002, 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 purchase power contracts). In October 2002, the CPUC issued a decision directing the resumption of the electric commodity procurement function by IOUs by January 1, 2003.

An unresolved issue is the ownership of certain power sale profits stemming from intermediate term purchase power contracts entered into by SDG&E during the early stages of California's electric utility industry restructuring. On December 19, 2002, the CPUC rendered a 3-to-2 decision approving the June 2002 proposed settlement previously described in the company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, that divides the profits from these contracts, $199 million for SDG&E customers and $173 million for SDG&E shareholders. Of the $199 million in profits allocated to customers, $175 million had already been credited to ratepayers in 2001. The remaining $24 million was applied as a balancing account transfer that reduced the AB 265 balancing account in December 2002. The profits allocated to customers reduce SDG&E's AB 265 undercollection, but do not adversely affect SDG&E's financial position, liquidity or results of operations. The term of a commissioner who voted to approve the settlement has expired, and a new commissioner has been appointed. On January 29, 2003, the CPUC's Office of Ratepayer Advocates, the City of San Diego and the Utility Consumers' Action Network, a consumer-advocacy group, filed requests for a CPUC rehearing of the decision. On February 13, 2003, the company filed its opposition to rehearing of the decision. Parties requesting a rehearing and parties to any rehearing may also appeal the CPUC's final decision to the California appellate courts.

Operating costs of SONGS Units 2 and 3 (including nuclear fuel and related financing costs) and incremental capital expenditures are recovered through the ICIP mechanism which allows SDG&E to receive approximately 4.4 cents per kilowatt-hour for SONGS generation. Any differences between the actual amounts of these costs and the incentive price affect net income. For the year ended December 31, 2002, ICIP contributed $50 million to SDG&E's net income. The CPUC has rejected an administrative law judge's proposed decision to end ICIP prior to its December 31, 2003 scheduled expiration date. However, the CPUC has also denied the previously approved market-based pricing for SONGS beginning in 2004 and instead provided for traditional rate-making treatment under which the SONGS ratebase would begin at zero, essentially eliminating earnings from SONGS until ratebase grows. The company has applied for rehearing of this decision.

See additional discussion of this and related topics in Note 13 of the notes to Consolidated Financial Statements.

Natural Gas Restructuring and Gas Rates

On December 11, 2001, the CPUC issued a decision adopting the following provisions affecting the structure of the natural gas industry in California, some of which could introduce additional volatility into the earnings of the California Utilities and other market participants: a system for shippers to hold firm, tradable rights to capacity on SoCalGas' major gas transmission lines, with SoCalGas' shareholders at risk for whether market demand for these rights will cover the cost of these facilities; a further unbundling of SoCalGas' storage services, giving SoCalGas greater upward pricing flexibility (except for storage service for core customers) but with increased shareholder risk for whether market demand will cover storage costs; new balancing services, including separate core and noncore balancing provisions; a reallocation among customer classes of the cost of interstate pipeline capacity held by SoCalGas and an unbundling of interstate capacity for natural gas marketers serving core customers; and the elimination of noncore customers' option to obtain natural gas procurement service from the California Utilities. During 2002 the California Utilities filed a proposed implementation schedule and revised tariffs and rules required for implementation. However, protests of these compliance filings were filed and the CPUC has not yet authorized implementation of most of the provisions of its decision. On December 30, 2002, the CPUC deferred acting on a plan to implement its decision.

Allowed Rates of Return

Effective January 1, 2003, SoCalGas' authorized rate of return on ratebase (ROR) is 8.68 percent and its rate of return on common equity (ROE) is 10.82 percent. These rates will be effective until the next periodic review by the CPUC unless market interest-rate changes are large enough to trigger an automatic adjustment prior thereto, which last occurred in October 2002 and adjusted rates downward from the previous 9.49 percent (ROR) and 11.6 percent (ROE) to the current levels. This change results in a revenue requirement decrease of $10.5 million.

Effective January 1, 2003, SDG&E's authorized rate of return on equity is 10.9 percent (increased from 10.6 percent) for SDG&E's electric distribution and natural gas businesses. This change results in a revenue requirement increase of $2.4 million ($1.9 million electric and $0.5 million natural gas) and increases SDG&E's overall rate of return from 8.75 percent to 8.77 percent. These rates remain in effect through 2003.

Either utility can earn more than the authorized rate by controlling costs below approved levels or by achieving favorable results in certain areas such as various incentive mechanisms. In addition, earnings are affected by customer growth.

Cost of Service (COS) and Performance-Based Regulation

The COS and PBR cases for the California Utilities were filed on December 20, 2002. The filings outline projected expenses (excluding the commodity cost of electricity or natural gas consumed by customers or expenses for programs such as low-income assistance) and revenue requirements for 2004 and a formula for 2005 through 2008. SoCalGas' cost of service study proposes an increase in natural gas base rate revenues of $130 million. SDG&E's cost of service study proposes increases in electric and natural gas base rate revenues of $58.9 million and $21.6 million, respectively. The filings also requested a continuance and expansion of PBR in terms of earnings sharing and performance service standards that include both reward and penalty provisions related to customer satisfaction, employee safety and system reliability. The resulting new base rates are expected to be effective on January 1, 2004. A CPUC decision is expected in late 2003. The California Utilities' profitability is dependent upon their ability to control costs within base rates. The California Utilities' PBR mechanisms are in effect through December 31, 2003, at which time the mechanisms will be updated. That update will include, among other things, a reexamination of the California Utilities' reasonable costs of operation to be allowed in rates.

An October 10, 2001 decision denied the California Utilities' request to continue equal sharing between ratepayers and shareholders of the estimated savings for the merger discussed in Note 1 and, instead, ordered that all of the estimated 2003 merger savings go to ratepayers. This decision will adversely affect the California Utilities' 2003 net income by $35 million.

Utility Integration

On September 20, 2001, the CPUC approved Sempra Energy's request to integrate the management teams of the California Utilities. The decision retains the separate identities of each utility and is not a merger. Instead, utility integration is a reorganization that consolidates senior management functions of the two utilities and returns to the utilities the majority of shared support services previously provided by Sempra Energy's centralized corporate center. Once implementation is completed, the integration is expected to result in more efficient and effective operations. In a related development, an August 2002 CPUC interim decision denied a request by the California Utilities to combine their natural gas procurement activities at this time, pending completion of the CPUC's ongoing investigation of market power issues.

SEMPRA ENERGY GLOBAL ENTERPRISES

Electric-Generation Assets

As discussed in "Cash Flows Used In Investing Activities" above, the company is involved in the development of several electric-generation projects that will significantly impact the company's future performance. The power plants that SER is building in Arizona, California and Mexico are on schedule to commence operations by January 2004. SER has approximately 2,700 megawatts of new generation in operation or under construction. The 570-megawatt Elk Hills power project, 50 percent owned by SER and located near Bakersfield, California, is expected to begin commercial operations in May 2003. The 1,250-megawatt Mesquite Power Plant near Phoenix, Arizona, is expected to commence commercial operations at 50-percent capacity in June 2003 and at full capacity in January 2004. Termoelectrica de Mexicali, a 600-megawatt power plant near Mexicali, Baja California, Mexico, is expected to commence commercial operations in the summer of 2003. The 305-megawatt Twin Oaks Power Plant located near Bremond, Texas, was acquired in October 2002. Electricity from the plants will be available for markets in California, Arizona, Texas and Mexico. SER's projected portfolio of plants in the western United States and Baja California may be used to supply power to California under SER's agreement with the DWR. See further discussion concerning SER's contract with the DWR in Note 15 of the notes to Consolidated Financial Statements.

See additional discussion of these projects in "Investments," below and in Notes 2, 3 and 15 of the notes to Consolidated Financial Statements.

Investments

As discussed in "Cash Flows Used In Investing Activities" above, during 2002, SET completed acquisitions that added base metals trading and warehousing to its trading business. These acquisitions are Sempra Metals Limited, Sempra Metals & Concentrates Corp., Henry Bath & Sons Limited and Henry Bath, Inc., and are further described in "Cash Flows From Investing Activities." In addition, on October 31, 2002, SER completed its previously announced acquisition of a 305-megawatt, coal-fired power plant (renamed Twin Oaks Power) from Texas-New Mexico Power Company for $120 million. SER has a five-year contract to sell substantially all of the output of the 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. These acquisitions contributed to Sempra Energy's earnings in 2002.

Also during 2002, SEI purchased over 300 acres of land north of Ensenada, Baja California, for $22.3 million. The land is the planned site of Energia Costa Azul, the LNG receiving terminal SEI is developing to bring natural gas supplies into northwestern Mexico and southern California. As currently planned, the plant would have a send-out capacity of 1 billion cubic feet per day of natural gas through a new 40-mile pipeline between the terminal and existing pipelines in the San Diego/Baja California border area. The plant is expected to cost $600 million and to commence commercial operations in 2007.

In February, 2003, Sempra LNG Corp., a newly created subsidiary of Global, announced an agreement to acquire the proposed Hackberry, La., LNG project from a subsidiary of Dynegy, Inc. Sempra LNG Corp. initially will pay Dynegy $20 million, with additional payments contingent on the performance of the project. The project has received preliminary approval from the FERC and expects a final decision later this year. If the project is approved, Sempra LNG Corp. would build an LNG receiving facility capable of processing up to 1.5 billion cubic feet per day of natural gas. The total cost of the project is expected to be about $700 million. The project could begin commercial operations as early as 2007.

See additional discussion of these investments and projects in "Capital Expenditures for Property, Plant and Equipment" above and in Notes 2, 3 and 15 of the notes to Consolidated Financial Statements.

The devaluation of the Argentine peso, which is noted above and further described in Note 3 of the notes to Consolidated Financial Statements, is expected to have an adverse effect on future earnings of the Argentine operations, but the extent of the effect is not yet determinable.

MARKET RISK

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

The company's policy is to use derivative physical and financial instruments to reduce its exposure to fluctuations in interest rates, foreign-currency exchange rates and commodity prices. The company also uses and trades derivative physical and financial instruments in its energy trading and marketing activities. Transactions involving these financial instruments are with major exchanges and other firms believed to be credit worthy. The use of these instruments exposes the company to market and credit risks which, at times, may be concentrated with certain counterparties. At December 31, 2002, SET was due approximately $100 million from the ISO, for which the company believes adequate reserves have been recorded. Except for the ISO receivable there were no unusual concentrations at December 31, 2002, that would indicate an unacceptable level of risk. Credit risks associated with concentration are discussed below under "Credit Risk."

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, 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.

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

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

	95%	99%
December 31, 2002	$4.6	$6.5
2002 average	6.2	8.7
December 31, 2001	6.9	9.7
2001 average	6.1	8.6

SES derives a substantial 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 carry minimal market risk. Exchange-traded and over-the-counter instruments are used to hedge contracts.

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

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

The following discussion of the company's primary market-risk exposures as of December 31, 2002 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, petroleum, metals, electricity, 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 portion of its revenue from delivering electric and gas supplies to its customers. Such contracts are designed 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 and storage activity. However, the California Utilities may, at times, be exposed to market risk as a result of activities under SDG&E's natural gas PBR and electric procurement 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 and trading framework. As of December 31, 2002, the total VaR of the California Utilities' natural gas and electric positions was not material.

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. With the restructuring of the regulatory process, the CPUC has permitted greater flexibility in the use of debt. As a result, some recent debt offerings have been selected with short-term maturities to take advantage of yield curves, or have used a combination of fixed-rate and floating-rate debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures when appropriate, based upon market conditions.

At December 31, 2002, the California Utilities had $1.9 billion of fixed-rate debt and $0.1 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, 2002, utility fixed-rate debt had a one-year VaR of $394 million and utility variable-rate debt had a one-year VaR of $0.1 million. Non-utility debt (fixed-rate and variable-rate) was $2.3 billion at December 31, 2002, with a one-year VaR of $199 million.

At December 31, 2002, the notional amount of interest-rate swap transactions totaled $500 million. See Notes 5 and 10 of the notes to Consolidated Financial Statements for further information regarding these swap transactions.

In addition the company is ultimately subject to the effect of interest rate fluctuation on the assets of its pension plan.

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 under the oversight of the Energy Risk Management Oversight Committee, assisted by the ERMG and the California Utility's credit department. Using rigorous models, the ERMG continuously calculates current and potential credit risk to counterparties to ensure the risk stays within approved limits. The company avoids concentration of counterparties 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, and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. At December 31, 2002, SET was due approximately $100 million from the ISO, for which the company believes adequate reserves have been recorded. Except for this matter, neither the company nor its subsidiaries are party to any material concentration of credit risk.

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

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

Foreign-Currency-Rate Risk

The company is subject to foreign-currency-rate risk in its international operations. The company has investments in entities whose functional currency is not the U.S. dollar, which exposes the company to foreign exchange movements, primarily in Latin American currencies. As a result of the devaluation of the Argentine peso, as of December 31, 2002, SEI has adjusted its investment in its two unconsolidated Argentine subsidiaries downward by $223 million, which is included in "other comprehensive income (loss)" on the Consolidated Balance Sheets. As the Argentine peso has been significantly devalued and will float freely in the foreign exchange market, the company recognizes that both income and cash flows associated with the investments are likely to be reduced; however, the company believes that they will remain sufficiently positive to support the carrying values of the investments. The company does not anticipate adverse developments that would change this view. On September 5, 2002, SEI filed for international arbitration under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments resulting from government actions. 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, 2002, the company had no significant arrangements of this type.

CRITICAL ACCOUNTING POLICIES

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:

Statement of Financial Accounting Standards (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 otherwise be recorded, absent the principles contained in SFAS 71.

SFAS 133 *"Accounting for Derivative Instruments and Hedging Activities"* and SFAS 138 *"Accounting for Certain Derivative Instruments and Certain Hedging Activities,"* have a significant effect on the balance sheets of the California Utilities but have no significant effect on their income statements because of the principles contained in SFAS 71.

Issue 02-3 of the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) *"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 is being 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 and SFAS 138, which have a similar effect.

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 realized values (including the likelihood of fully realizing the value of the investments in Argentina under the Bilateral Investment Treaty).
- The collectibility of regulatory and other assets.
- The costs to be incurred in fulfilling certain contracts that have been marked to market.
- The likelihood of recovery of various deferred tax assets.

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 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 marked-to-market contracts are based on prior experience. 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.

NEW ACCOUNTING STANDARDS

New pronouncements by the FASB that have recently become effective or are yet to be effective are SFAS 142 through SFAS 149 and Interpretations 45 and 46. They are described in Note 1 of the notes to Consolidated Financial Statements. SFAS 142 affects net income by replacing the amortization of goodwill with periodic reviews thereof for impairment with charges against income when impairment is found. SFAS 143 requires accounting and disclosure changes concerning legal obligations related to future asset retirements. SFAS 144 supercedes SFAS 121 in dealing with other asset impairment issues. SFAS 145 makes technical corrections to previous statements. SFAS 146 deals with exit and disposal activities, replacing EITF Issue 94-3. SFAS 147 deals with acquisitions of financial institutions. SFAS 148 amends SFAS 123 and adds two additional transition methods to the fair value method of accounting for stock-based compensation. SFAS 149 establishes standards for accounting for financial instruments with characteristics of liabilities and equity. Interpretation 45 clarifies that a guarantor is required to recognize a liability for the fair value of the obligation undertaken in issuing a guarantee. Interpretation 46 addresses consolidation by business enterprises of variable-interest entities (previously referred to as "special-purpose entities" in most cases). Pronouncements that have or potentially could have a material effect on future earnings are described below.

SFAS 143, "Accounting for Asset Retirement Obligations": SFAS 143, issued in July 2001, addresses financial accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets. It requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. SFAS 143 is effective for the company beginning in 2003. See further discussion in Note 1 of the notes to Consolidated Financial Statements.

SFAS 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity": On January 22, 2003, the FASB directed its staff to prepare a draft of SFAS 149. The final draft is expected to be issued in March 2003. The statement will establish standards for accounting for financial instruments with characteristics of liabilities, equity, or both. The FASB decided that SFAS 149 will prohibit the presentation of certain items in the mezzanine section (the portion of a balance sheet between liabilities and equity) of the statement of financial position. As such, certain mandatorily redeemable preferred stock, which is currently included in the mezzanine section, may be classified as a liability once SFAS 149 goes into effect. The proposed effective date of SFAS 149 is July 1, 2003 for the company.

EITF Issue 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, EITF Issue 02-3, codified and reconciled existing guidance on the recognition and reporting of gains and losses on energy trading contracts and addressed other aspects of the accounting for contracts involved in energy trading and risk management activities. Among other things, the consensus requires that SES change its method of recording trading activities from gross to net.

In October 2002, the EITF reached a consensus to rescind Issue 98-10 *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities,"* the basis for mark-to-market accounting used for recording energy-trading activities by SET and SES. The consensus requires that all new energy-related contracts entered into subsequent to October 25, 2002, including inventory, should be accounted for under accrual accounting and will not qualify for mark-to-market accounting unless the contracts meet the requirements stated under SFAS 133 *"Accounting for Derivative Instruments and Hedging Activities"* and all contracts entered into on or before October 25, 2002 are similarly affected beginning January 1, 2003. See Note 10 of the notes to Consolidated Financial Statements for additional information concerning SFAS 133 derivatives.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

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

Forward-looking statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others, local, regional, national and international economic, competitive, political, legislative and regulatory conditions and developments; actions by the CPUC, the California Legislature, the DWR and the FERC; 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 pace of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this 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)

	2002	2001	2000	1999	1998
OPERATING REVENUES					
California utilities:					
Gas	**$ 3,255**	$ 4,371	$ 3,305	$ 2,911	$ 2,752
Electric	**1,262**	1,676	2,184	1,818	1,865
Other	**1,503**	1,683	1,271	631	364
Total	**$ 6,020**	$ 7,730	$ 6,760	$ 5,360	$ 4,981
Operating income	**$ 987**	$ 997	$ 884	$ 763	$ 626
Income before extraordinary item	**$ 575**	$ 518	$ 429	$ 394	$ 294
Net income	**$ 591**	$ 518	$ 429	$ 394	$ 294
Income before extraordinary item per common share:					
Basic	**$ 2.80**	$ 2.54	$ 2.06	$ 1.66	$ 1.24
Diluted	**$ 2.79**	$ 2.52	$ 2.06	$ 1.66	$ 1.24
Net income per common share:					
Basic	**$ 2.88**	$ 2.54	$ 2.06	$ 1.66	$ 1.24
Diluted	**$ 2.87**	$ 2.52	$ 2.06	$ 1.66	$ 1.24
Dividends declared per common share	**$ 1.00**	$ 1.00	$ 1.00	$ 1.56	$ 1.56
Pretax income/revenue	**12.0%**	9.5%	10.3%	10.7%	8.7%
Return on common equity	**21.4%**	19.5%	15.7%	13.4%	10.0%
Effective income tax rate	**20.2%**	29.1%	38.6%	31.2%	31.9%
Dividend payout ratio:					
Basic (a)	**35.7%**	39.4%	48.5%	94.0%	125.8%
Diluted (a)	**35.8%**	39.7%	48.5%	94.0%	125.8%
Price range of common shares	**$ 26.25-15.50**	$ 28.61-17.31	$ 24.88-16.19	$ 26.00-17.13	$ 29.31-23.75
AT DECEMBER 31					
Current assets	**$ 7,010**	$ 4,790	$ 6,525	$ 3,090	$ 2,482
Total assets	**$17,757**	$15,080	$15,540	$11,124	$ 10,456
Current liabilities	**$ 7,247**	$ 5,472	$ 7,490	$ 3,236	$ 2,466
Long-term debt (excludes current portion)	**$ 4,083**	$ 3,436	$ 3,268	$ 2,902	$ 2,795
Shareholders' equity	**$ 2,825**	$ 2,692	$ 2,494	$ 2,986	$ 2,913
Common shares outstanding (in millions)	**204.9**	204.5	201.9	237.4	237.0
Book value per common share	**$ 13.79**	$ 13.16	$ 12.35	$ 12.58	$ 12.29
Price/earnings ratio (a)	**8.4**	9.7	11.3	10.5	20.5
Number of meters (in thousands):					
Natural gas	**6,127**	6,053	5,981	5,915	5,837
Electricity	**1,278**	1,258	1,238	1,218	1,192

(a) Based on income before extraordinary item.

Statement of Management's Responsibility for Consolidated Financial Statements

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

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

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

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

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

Neal E. Schmale
Executive Vice President and
Chief Financial Officer

Frank H. Ault
Senior Vice President and Controller

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Sempra Energy:

We have audited the accompanying consolidated balance sheets of Sempra Energy and subsidiaries (the "Company") as of December 31, 2002 and 2001, 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, 2002. 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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

San Diego, California
February 14, 2003

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SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED INCOME

(Dollars in millions, except per share amounts)	Years ended December 31, **2002**	2001	2000
OPERATING REVENUES			
California utilities:			
Natural gas	**$ 3,255**	$ 4,371	$ 3,305
Electric	**1,262**	1,676	2,184
Other	**1,503**	1,683	1,271
Total	**6,020**	7,730	6,760
OPERATING EXPENSES			
California utilities:			
Cost of natural gas distributed	**1,381**	2,549	1,599
Electric fuel and net purchased power	**297**	782	1,326
Other cost of sales	**709**	873	648
Other operating expenses	**1,873**	1,760	1,560
Depreciation and amortization	**596**	579	563
Franchise fees and other taxes	**177**	190	180
Total	**5,033**	6,733	5,876
Operating income	**987**	997	884
Other income — net	**57**	86	127
Preferred dividends of subsidiaries	**(11)**	(11)	(11)
Trust preferred distributions by subsidiary	**(18)**	(18)	(15)
Interest expense	**(294)**	(323)	(286)
Income before income taxes	**721**	731	699
Income taxes	**146**	213	270
Income before extraordinary item	**575**	518	429
Extraordinary item, net of tax (Note 1)	**16**	—	—
Net income	**$ 591**	$ 518	$ 429
Weighted-average number of shares outstanding:			
Basic*	**205,003**	203,593	208,155
Diluted*	**206,062**	205,338	208,345
Income before extraordinary item per share of common stock			
Basic	**$ 2.80**	$ 2.54	$ 2.06
Diluted	**$ 2.79**	$ 2.52	$ 2.06
Net income per share of common stock			
Basic	**$ 2.88**	$ 2.54	$ 2.06
Diluted	**$ 2.87**	$ 2.52	$ 2.06
Common dividends declared per share	**$ 1.00**	$ 1.00	$ 1.00

* In thousands of shares

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, **2002**	2001
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 455**	$ 605
Accounts receivable — trade	**754**	657
Accounts and notes receivable — other	**135**	138
Due from unconsolidated affiliates	**80**	57
Income taxes receivable	**—**	98
Deferred income taxes	**20**	—
Trading assets	**5,064**	2,740
Fixed-price contracts and other derivatives	**3**	57
Regulatory assets arising from fixed-price contracts and other derivatives	**151**	168
Other regulatory assets	**75**	75
Inventories	**134**	124
Other	**139**	71
Total current assets	**7,010**	4,790
Investments and other assets:		
Fixed-price contracts and other derivatives	**42**	27
Due from unconsolidated affiliates	**57**	—
Regulatory assets arising from fixed-price contracts and other derivatives	**812**	784
Other regulatory assets	**532**	1,004
Nuclear-decommissioning trusts	**494**	526
Investments	**1,313**	1,169
Sundry	**665**	564
Total investments and other assets	**3,915**	4,074
Property, plant and equipment:		
Property, plant and equipment	**13,816**	12,806
Less accumulated depreciation and amortization	**(6,984)**	(6,590)
Total property, plant and equipment — net	**6,832**	6,216
Total assets	**$17,757**	$15,080

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2002	2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	**$ 570**	$ 875
Accounts payable — trade	**694**	701
Accounts payable — other	**50**	113
Income taxes payable	**22**	—
Deferred income taxes	**—**	70
Trading liabilities	**4,094**	1,793
Dividends and interest payable	**133**	133
Regulatory balancing accounts — net	**578**	733
Regulatory liabilities	**18**	19
Fixed-price contracts and other derivatives	**153**	171
Current portion of long-term debt	**281**	242
Other	**654**	622
Total current liabilities	**7,247**	5,472
Long-term debt	**4,083**	3,436
Deferred credits and other liabilities:		
Due to unconsolidated affiliate	**162**	160
Customer advances for construction	**91**	72
Post-retirement benefits other than pensions	**136**	145
Deferred income taxes	**800**	847
Deferred investment tax credits	**90**	95
Fixed-price contracts and other derivatives	**813**	788
Regulatory liabilities	**121**	86
Deferred credits and other liabilities	**985**	883
Total deferred credits and other liabilities	**3,198**	3,076
Preferred stock of subsidiaries	**204**	204
Mandatorily redeemable trust preferred securities	**200**	200
Commitments and contingent liabilities (Note 15)		
SHAREHOLDERS' EQUITY		
Preferred stock (50,000,000 shares authorized, none issued)	**—**	—
Common stock (750,000,000 shares authorized; 204,911,572 and 204,475,362 shares outstanding at December 31, 2002 and December 31, 2001, respectively)	**1,436**	1,495
Retained earnings	**1,861**	1,475
Deferred compensation relating to ESOP	**(33)**	(36)
Accumulated other comprehensive income (loss)	**(439)**	(242)
Total shareholders' equity	**2,825**	2,692
Total liabilities and shareholders' equity	**$17,757**	$15,080

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)	Years ended December 31, 2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 591**	$ 518	$ 429
Adjustments to reconcile net income to net cash provided by operating activities:			
Extraordinary item, net of tax	**(16)**	—	—
Depreciation and amortization	**596**	579	563
Foreign currency loss (gain)	**(63)**	—	—
Customer refunds paid	**—**	(127)	(628)
Deferred income taxes and investment tax credits	**(92)**	106	258
Equity in (income) losses of unconsolidated affiliates	**55**	(12)	(62)
Gain on sale of Energy America	**—**	(29)	—
Loss on surrender of Nova Scotia franchise	**—**	30	—
Loss (gain) on sale and disposition of assets	**14**	(14)	—
Fixed-price contracts and other derivatives income	**(5)**	(1)	—
Changes in other assets	**168**	(214)	22
Changes in other liabilities	**40**	99	(108)
Net changes in other working capital components	**83**	(203)	408
Net cash provided by operating activities	**1,371**	732	882
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	**(1,214)**	(1,068)	(759)
Investments and acquisitions of affiliates, net of cash acquired	**(442)**	(111)	(243)
Dividends received from unconsolidated affiliates	**11**	80	30
Net proceeds from sale of assets	**—**	128	24
Loan to affiliate	**—**	(57)	—
Other — net	**(14)**	(11)	24
Net cash used in investing activities	**(1,659)**	(1,039)	(924)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common stock dividends	**(205)**	(203)	(244)
Repurchases of common stock	**(16)**	(1)	(725)
Issuances of common stock	**13**	41	12
Issuance of trust preferred securities	**—**	—	200
Issuances of long-term debt	**1,150**	675	813
Payments on long-term debt	**(479)**	(681)	(238)
Loan from unconsolidated affiliate	**—**	160	—
Increase (decrease) in short-term debt — net	**(307)**	310	386
Other — net	**(18)**	(26)	(12)
Net cash provided by financing activities	**138**	275	192
Increase (decrease) in cash and cash equivalents	**(150)**	(32)	150
Cash and cash equivalents, January 1	**605**	637	487
Cash and cash equivalents, December 31	**$ 455**	$ 605	$ 637

See notes to Consolidated Financial Statements.

(Dollars in millions)	Years ended December 31, **2002**	2001	2000
CHANGES IN OTHER WORKING CAPITAL COMPONENTS			
(Excluding cash and cash equivalents, and debt due within one year)			
Accounts and notes receivable	**$ (121)**	$ 353	$(655)
Net trading assets	**66**	(362)	(290)
Income taxes — net	**86**	(121)	120
Due to/from affiliates — net	**(69)**	—	—
Inventories	**(11)**	33	(97)
Regulatory balancing accounts	**115**	70	545
Regulatory assets and liabilities	**1**	39	(2)
Other current assets	**102**	69	(84)
Accounts payable	**(103)**	(302)	733
Other current liabilities	**17**	18	138
Net change in other working capital components	**$ 83**	$(203)	$ 408
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	**$ 279**	$ 302	$ 291
Income tax payments, net of refunds	**$ 140**	$ 138	$ 104
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Acquisition of subsidiaries:			
Assets acquired	**$1,134**	$ —	$ 40
Cash paid, net of cash acquired	**(119)**	—	(39)
Liabilities assumed	**$1,015**	$ —	$ 1

See notes to Consolidated Financial Statements.

SEMPRA ENERGY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
For the years ended December 31, 2002, 2001 and 2000

(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, 1999		$1,966	$1,101	$(42)	$ (39)	$2,986
Net income	$429		429			429
Comprehensive income adjustments:						
Foreign currency translation losses (Note1)	(2)				(2)	(2)
Available-for-sale securities	(10)				(10)	(10)
Pension	2				2	2
Comprehensive income	$419					
Common stock dividends declared			(201)			(201)
Sale of common stock		11				11
Repurchase of common stock		(558)	(167)			(725)
Long-term incentive plan		1				1
Common stock released from ESOP				3		3
Balance at December 31, 2000		1,420	1,162	(39)	(49)	2,494
Net income	$518		518			518
Comprehensive income adjustments:						
Foreign currency translation losses (Note 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)**
Repurchase of common stock		**(16)**				**(16)**
Sale of common stock		**18**				**18**
Common stock released from ESOP				**3**		**3**
Balance at December 31, 2002		**$1,436**	**$1,861**	**$(33)**	**$(439)**	**$2,825**

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Business Combination

Sempra Energy (the company) was formed as a holding company for Enova Corporation (Enova) and Pacific Enterprises (PE) in connection with a business combination of Enova and PE that was completed on June 26, 1998.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Sempra Energy and all majority-owned subsidiaries. Investments in affiliated companies at 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, PE divested its merchandising operations and most of its oil and natural gas exploration and production business. In connection with the divestitures, PE effected a quasi-reorganization for financial reporting purposes as of December 31, 1992. Certain of the liabilities established in connection with the quasi-reorganization, including various income tax issues, were favorably resolved in 2001, resulting in restoring $35 million to shareholders' equity in that year. This did not affect the calculation of net income or comprehensive income. The remaining liabilities will be resolved in future years. Management believes the provisions established for these matters are adequate.

Use of Estimates in the Preparation of the Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of 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 future reductions in rates for amounts due to customers. To the extent that portions of the utility operations cease to be subject to SFAS 71, or recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets and liabilities would be written off. In addition, SFAS 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* affects utility plant and regulatory assets such that a loss must be recognized whenever a regulator excludes all or part of an asset's cost from ratebase. The application of SFAS 144 continues to be evaluated in connection with industry restructuring. Information concerning regulatory assets and liabilities is described below in "Revenues", "Regulatory Balancing Accounts," and "Regulatory Assets and Liabilities," and industry restructuring is described in Notes 13 and 14.

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2002, represent net payables (payables net of receivables) of $184 million and $394 million for SoCalGas and SDG&E, respectively. The corresponding amounts at December 31, 2001 were net payables of $158 million and $575 million for SoCalGas and SDG&E, respectively. The undercollected electric commodity costs accumulated under Assembly Bill (AB) 265 are anticipated to be recovered in rates (recovery is expected to occur before the end of 2005) and are included in "regulatory balancing accounts—net" at December 31, 2002.

Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. As a result of California's electric-restructuring law, fluctuations in certain costs and consumption levels that had been balanced now affect earnings from electric operations. In addition, fluctuations in certain costs and consumption levels affect earnings for SDG&E's natural gas operations. As SoCalGas' natural gas operations are mostly balanced, such fluctuations do not affect earnings. In December 2002, the CPUC issued a decision approving 100 percent balancing account treatment for variances between forecast and actual for SoCalGas' noncore revenues and throughput. The change eliminates the impact on earnings from any throughput and revenue variances compared to adopted forecast levels, effective January 1, 2003. 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 (which represent probable future revenues associated with certain costs that will be recovered from customers through the rate-making process) and regulatory liabilities (which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process). They are amortized over the periods in which the costs are recovered from or refunded to customers in regulatory revenues.

Regulatory assets (liabilities) as of December 31 consist of the following:

(Dollars in millions)	**2002**	2001
SDG&E		
Fixed-price contracts and other derivatives	**$ 638**	$ 715
Recapture of temporary discount*	**326**	409
Undercollected electric commodity costs**	**—**	392
Deferred taxes recoverable in rates	**190**	162
Unamortized loss on retirement of debt — net	**49**	52
Employee benefit costs	**35**	39
Other	**5**	26
Total	**1,243**	1,795
SoCalGas		
Environmental remediation	**43**	55
Fixed-price contracts and other derivatives	**325**	232
Unamortized loss on retirement of debt — net	**38**	41
Deferred taxes refundable in rates	**(164)**	(158)
Employee benefit costs	**(142)**	(132)
Other	**8**	5
Total	**108**	43
PE — Employee benefit costs	**80**	88
Total PE consolidated	**188**	131
Total	**$1,431**	$1,926

* 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 2004.

** The undercollected electric commodity costs accumulated under Assembly Bill 265 are anticipated to be recovered in rates before the end of 2005 and are included in regulatory balancing accounts—net at December 31, 2002.

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

	2002	2001
Current regulatory assets	**$ 226**	$ 243
Noncurrent regulatory assets	**1,344**	1,788
Current regulatory liabilities	**(18)**	(19)
Noncurrent regulatory liabilities	**(121)**	(86)
Total	**$1,431**	$1,926

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

Cash and Cash Equivalents

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

Collection Allowance

The allowance for doubtful accounts receivable was $12 million, $22 million and $26 million at December 31, 2002, 2001 and 2000, respectively. The company recorded a provision for doubtful accounts of $13 million, $21 million and $25 million in 2002, 2001 and 2000, respectively.

The allowance for realization of trading assets was $53 million, $23 million and $8 million, at December 31, 2002, 2001 and 2000, respectively. The company recorded a provision for trading assets of $0.2 million, $15 million and $7 million in 2002, 2001 and 2000, 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 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 settlement of the contracts. Unrealized gains and losses on OTC transactions are reported separately as assets and liabilities unless a legal right of setoff exists under an enforceable master netting arrangement. Additionally, as a result of SET's acquisitions in 2002, the company acquired $0.8 billion of base metals inventory. As of December 31, 2002 and 2001, trading assets include commodity inventory of $2.0 billion and $165 million, respectively. In accordance with Emerging Issues Task Force (EITF) Issue 02-3, commodity inventory purchased on or before October 25, 2002 is carried at fair value, the majority of the inventory purchased after October 25, 2002 (base metals) is carried at fair value, and the remainder of the inventory purchased after October 25, 2002 is carried at average cost. On a limited basis, average cost includes the use of fair value for the quantity on hand at October 24, 2002, since historical cost data is not available for that portion. See Note 2 for further discussion of the acquisitions made. See further discussion of EITF Issue 02-3 below.

Futures and exchange-traded option transactions are recorded as contractual commitments on a trade-date basis and are carried at current market value based on current closing exchange quotations. Derivative commodity swaps and forward transactions are accounted for as contractual commitments on a trade-date basis and are carried at fair value derived from current dealer quotations and underlying commodity-exchange quotations. OTC options are carried at fair value based on the use of valuation models that utilize, among other things, current interest, commodity and volatility rates. For long-dated forward transactions, current market values are derived using internally developed valuation methodologies based on available market information. Where market rates are not quoted, current interest, commodity and volatility rates are estimated by reference to current market levels. Given the nature, size and timing of transactions, estimated values may differ significantly from realized values. Changes in market values are recorded in the calculation of net income. 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. Refer to "New Accounting Standards" below for a discussion of the rescission of EITF 98-10.

Inventories

At December 31, 2002, inventory, excluding amounts presented in trading assets, included natural gas of $77 million and materials and supplies of $57 million. The corresponding balances at December 31, 2001 were $68 million and $56 million, respectively. Natural gas at the California Utilities ($74 million and $68 million at December 31, 2002 and 2001, respectively) is valued by the last-in first-out (LIFO) method. When the California Utilities' inventory is consumed, differences between this LIFO valuation and replacement cost will be reflected in customer rates. Materials and supplies at the California Utilities are generally valued at the lower of average cost or market.

Property, Plant and Equipment

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

The cost of utility plant includes labor, materials, contract services and related items, and an allowance for funds used during construction (AFUDC). The cost of most retired depreciable utility plant, plus removal costs minus salvage value, is charged to accumulated depreciation.

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)	**2002**	2001	**2002**	2001	2000
California utilities:					
Natural gas operations	**$ 7.7**	$ 7.5	**4.25%**	4.25%	4.29%
Electric distribution	**3.0**	2.9	**4.66%**	4.67%	4.67%
Electric transmission	**0.9**	0.8	**3.17%**	3.19%	3.21%
Other electric	**0.6**	0.3	**9.37%**	8.46%	8.33%
Total	**12.2**	11.5			
Other operations	**1.6**	1.3	**various**	various	various
Total	**$13.8**	$12.8			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $4.5 billion and $2.2 billion, respectively, at December 31, 2002, and were $4.2 billion and $2.1 billion, respectively, at December 31, 2001. 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, shown in the Statements of Consolidated Income, although it is not a current source of cash. AFUDC amounted to $34 million, $17 million and $13 million for 2002, 2001 and 2000, respectively. Total carrying costs capitalized, including AFUDC and the impact of Sempra Energy Resources' (SER) construction projects, were $63 million, $28 million and $16 million for 2002, 2001 and 2000, 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 is less than the carrying amount of the assets. If that comparison indicates that the assets' carrying value may be permanently impaired, such potential impairment is measured based on the difference between the carrying amount and the fair value of the assets based on quoted market prices or, if market prices are not available, on the estimated discounted cash flows. This calculation is performed at the lowest level for which separately identifiable cash flows exist. See further discussion of SFAS 144 in "New Accounting Standards".

Nuclear-Decommissioning Liability

At December 31, 2002 and 2001, deferred credits and other liabilities include $139 million and $151 million, respectively, of accrued decommissioning costs associated with SDG&E's interest in San Onofre Nuclear Generating Station (SONGS) Unit 1, which was permanently shut down in 1992. The corresponding liability for SONGS Units 2 and 3 decommissioning (included in accumulated depreciation and amortization) is $355 million and $375 million at December 31, 2002 and 2001, respectively. Additional information on SONGS decommissioning costs is included below in "New Accounting Standards."

Comprehensive Income

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

Stock-Based Compensation

At December 31, 2002, the company has stock-based employee compensation plans, which are described more fully in Note 9**.** The company accounts for those 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.

The following table illustrates the effect on net income and earnings per share if the company had applied the fair value recognition provisions of SFAS 123, *"Accounting for Stock-Based Compensation,"* and SFAS 148, "*Accounting for Stock-Based Compensation—Transition and Disclosure***.**"

Dollars in millions, except per share amounts	Years Ended December 31		
	2002	2001	2000
Net income as reported	**$ 591**	$ 518	$ 429
Stock-based employee compensation expense determined under the fair value based method, net of related income taxes	**(8)**	(1)	—
Pro forma net income	**$ 583**	$ 517	$ 429
Earnings per share:			
Basic – as reported	**$2.88**	$2.54	$2.06
Basic – pro forma	**$2.84**	$2.54	$2.06
Diluted – as reported	**$2.87**	$2.52	$2.06
Diluted – pro forma	**$2.83**	$2.52	$2.06

Revenues

Revenues of the California Utilities are 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 these revenues are 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) 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 as SDG&E sold power into the PX/ISO and then purchased power therefrom. 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 one-year to three-year terms. Operating revenue includes amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

Operating costs of SONGS Units 2 and 3 (including nuclear fuel and nuclear fuel financing costs) and incremental capital expenditures are recovered through the Incremental Cost Incentive Pricing (ICIP) mechanism which allows SDG&E to receive approximately 4.4 cents per kilowatt-hour (kWh) through 2003. Any differences between these costs and the incentive price affect net income and, for the year ended December 31, 2002, the ICIP contributed $50 million to SDG&E's net income. The CPUC has rejected an administrative law judge's proposed decision to end ICIP prior to its December 31, 2003 scheduled expiration date. However, the CPUC has also denied the previously approved market-based pricing for SONGS beginning in 2004 and instead provided for traditional rate-making treatment, under which the SONGS ratebase would begin at zero, essentially eliminating earnings from SONGS until ratebase grows. The company has applied for rehearing of this decision.

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

As a writer of options, SET generally receives an option premium and then manages the risk of an unfavorable change in the value of the underlying commodity by entering into related transactions or by other means. Forward and future transactions are contracts for delayed delivery of commodities in which the counterparty agrees to make or take delivery at a specified price. Commodity swap transactions may involve the exchange of fixed and floating payment obligations without the exchange of the underlying commodity. These financial instruments represent contracts with counterparties whereby payments are linked to or derived from market indices or on terms predetermined by the contract, which may or may not be financially settled by SET. All of SET's derivative transactions are held for trading and marketing purposes and were recorded at current fair value. Any post October 25, 2002 non-derivative contracts are being accounted for on an accrual basis. Hence, the related profit or loss will be recognized as the contract is performed. Inventory purchased after October 25, 2002 is being carried on a lower of cost or market basis.

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 Issue 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 2002, electric energy sales to the DWR accounted for a significant portion of total SER revenues.

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

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 devaluation 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 downward by $103 million and $120 million in 2002 and 2001, respectively. These non-cash adjustments did not affect net income, but did reduce comprehensive income and increase accumulated other comprehensive income (loss). Additional information concerning these investments is described in Note 3.

Related Party Transactions—*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 (8.863% at December 31, 2002) and are due on December 11, 2003. The total balance outstanding under the notes was $57 million at December 31, 2002 and 2001. At December 31, 2002, this amount is included in non-current assets, under the caption "Due from unconsolidated affiliates." Additionally, at December 31, 2002 SET had $79 million due from its affiliate, Atlantic Electric & Gas and the company had $1 million due from other affiliates. This amount is included in current assets, under the caption "Due from unconsolidated affiliates".

New Accounting Standards

SFAS 142, "Goodwill and Other Intangible Assets": In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS 142, which provides guidance on how to account for goodwill and other intangible assets after an acquisition is complete, and is effective for the company in 2002. 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 and $35 million in 2001 and 2000, respectively. 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. Fair value was determined 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.

The following table shows what net income and earnings per share would have been if amortization related to goodwill that is no longer being amortized had also not been amortized in prior periods. (This comparison ignores the fact that a 2002 goodwill impairment charge would have been larger if goodwill had not been amortized in prior periods.)

	Years ended December 31,		
Dollars in millions, except for the per share amounts	**2002**	2001	2000
Reported income before extraordinary item	**$ 575**	$ 518	$ 429
Add: goodwill amortization, net of tax	**—**	15	21
Pro forma adjusted income before extraordinary item	**$ 575**	$ 533	$ 450
Reported net income	**$ 591**	$ 518	$ 429
Add: goodwill amortization, net of tax	**—**	15	21
Pro forma adjusted net income	**$ 591**	$ 533	$ 450
Reported basic earnings per share	**$2.88**	$2.54	$2.06
Add: goodwill amortization, net of tax	**—**	.07	.10
Pro forma adjusted basic earnings per share	**$2.88**	$2.61	$2.16
Reported diluted earnings per share	**$2.87**	$2.52	$2.06
Add: goodwill amortization, net of tax	**—**	.07	.10
Pro forma adjusted diluted earnings per share	**$2.87**	$2.59	$2.16

During 2002, SET completed several acquisitions as further discussed in Note 2. As a result of SET's acquisitions, the company recorded $21 million of goodwill on the Consolidated Balance Sheets and $16 million as an after-tax extraordinary gain for 2002.

The change in the carrying amount of goodwill (included in noncurrent sundry assets on the Consolidated Balance Sheets) for the years ended December 31, 2002 and 2001 are as follows:

(Dollars in millions)	SET	Other	Total
Balance as of January 1, 2001	$131	$57	$188
Amortization of goodwill	(11)	(5)	(16)
Balance as of December 31, 2001	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

SET is the only reportable segment that has goodwill. In addition, unamortized goodwill related to unconsolidated subsidiaries (included in investments on the Consolidated Balance Sheets), primarily those located in South America, was $294 million at both December 31, 2002 and 2001 before foreign currency translation adjustments. Including foreign currency translation adjustments, these amounts were $219 million and $233 million, respectively. Unamortized other intangible assets were not material at December 31, 2002 and 2001.

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. This applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of 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. SFAS 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. The items noted below were identified by the company to have a material asset retirement obligation.

Adoption of SFAS 143 will change the accounting for the decommissioning of the company's share of SONGS. Prior to the adoption of SFAS 143, the company recorded the obligation for decommissioning over the lives of the plants. At December 31, 2002, the company's share of decommissioning cost for the SONGS' units has been estimated to be $309 million in 2002 dollars, based on a 2001 cost study filed with the CPUC. The adoption of this standard, effective January 1, 2003, will require a cumulative adjustment to adjust plant assets and decommissioning liabilities to the values they would have been had this standard been employed from the in-service dates of the plants. Upon adoption of SFAS 143 in 2003, the company will record an addition of $70 million to utility plant, representing the company's share of SONGS estimated future decommissioning costs (as discounted to the present value at the date the various units began operation), and a corresponding retirement obligation liability of $309 million. The nuclear decommissioning trusts' balance of $494 million at December 31, 2002 represents amounts collected for future decommissioning costs and earnings thereon, and has a corresponding offset in accumulated depreciation ($355 million related to SONGS Units 2 and 3) and deferred credits ($139 million related to SONGS Unit 1). The difference between the amounts results in a regulatory liability of $214 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. See further discussion of SONGS' decommissioning and the related nuclear decommissioning trusts in Note 6.

As of January 1, 2003, the company had additional asset retirement obligations estimated to be $23 million associated with the retirement of a power plant and a storage field.

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."* SFAS 144 applies to all long-lived assets, including discontinued operations. SFAS 144 requires that those long-lived assets classified as held for sale be measured at the lower of carrying amount (cost less accumulated depreciation) or fair value less cost to sell. Discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The company has identified no material effects to the financial statements from the implementation of SFAS 144.

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, the amendment to SFAS 123 will not have any effect on the company's financial statements. See Note 9 for additional information regarding stock-based compensation.

SFAS 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity": On January 22, 2003, the FASB directed its staff to prepare a draft of SFAS 149. The final draft is expected to be issued in March 2003. The statement will establish standards for accounting for financial instruments with characteristics of liabilities, equity, or both. Subsequent to the issuance of SFAS 149, certain investments that are currently classified as equity in the financial statements might have to be reclassified as liabilities. In addition, the FASB decided that SFAS 149 will prohibit the presentation of certain items in the mezzanine section (the portion of a balance sheet between liabilities and equity) of the statement of financial position. For example, certain mandatorily redeemable preferred stock, which is currently included in the mezzanine section, may be classified as a liability once SFAS 149 goes into effect. The proposed effective date of SFAS 149 is July 1, 2003 for the company.

EITF Issue 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 Issue 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. This 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 net and required no change.

The following table shows the impact of changing from gross to net presentations for energy trading activities on the company's revenues for prior years (dollars in millions):

	Years ended December 31,	
	2001	2000
Revenues as previously reported	**$8,078**	$7,037
Adjustment	**(348)**	(277)
Revenues as restated	**$7,730**	$6,760

In October 2002, the EITF reached a consensus to rescind Issue 98-10 *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities,"* the basis for fair value accounting used for recording energy-trading activities by SET and SES. The consensus requires that all new energy-related contracts entered into subsequent to October 25, 2002 should not be accounted pursuant to Issue 98-10. Instead, those contracts should be accounted for at historical cost and will not qualify for mark-to-market accounting unless the contracts meet the requirements stated under SFAS 133 *"Accounting for Derivative Instruments and Hedging Activities"*. Contracts entered into through October 25, 2002 are to be accounted for at fair value through December 31, 2002. Except for inventory, capacity contracts and natural gas storage, the company's transactions recorded at fair value by EITF Issue 98-10 will still be recorded at fair value based on SFAS 133 (see Note 10 for additional information concerning SFAS 133 derivatives). Furthermore, the EITF decided to retain the guidance in Issue 02-3, which states that energy trading contracts and derivative instruments under SFAS 133 must be presented on a net basis in the income statement whether or not physically settled. Adoption of this statement will result in a cumulative-effect charge in the first quarter of 2003 (preliminarily estimated to be less than $20 million after tax) and likely will have a material impact on the company's financial statements in future periods from the delay in profit recognition on transactions that were covered by EITF 98-10 but are not covered by SFAS 133.

FASB Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": In November 2002, the FASB issued Interpretation 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. Initial recognition and measurement provisions of the Interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. As of December 31, 2002, substantially all of the company's guarantees were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries to a third party. The only significant guarantee for which disclosure is required is that of the synthetic lease for the Mesquite Power Plant, which is also affected by FASB Interpretation 46, as described below.

FASB Interpretation 46, "Consolidation of Variable Interest Entities": In January 2003, the FASB issued Interpretation 46, which addresses consolidation by business enterprises of variable-interest entities. The interpretation is effective immediately for variable-interest entities created after January 31, 2003. For variable-interest entities created before February 1, 2003, the interpretation is effective for fiscal or interim periods beginning after June 15, 2003. As of December 31, 2002, the company had commitments of $70 million related to a synthetic lease agreement to finance the construction of the Mesquite Power Plant. As a synthetic lease, neither the plant asset nor the related liability is included on the Consolidated Balance Sheets. If they were, property, plant and equipment and long-term debt would each have been increased by $545 million at December 31, 2002, reflecting reimbursements for costs incurred on the project, including costs subject to collateralization requirements. Under Interpretation 46, the company would be required to increase property, plant and equipment and long-term debt by the total cost incurred and subject to collateralization requirements under the synthetic lease beginning July 1, 2003. See further discussion of the synthetic lease agreement in Note 15.

Other Accounting Standards: During 2002 and 2001 the FASB and the EITF issued several statements that are currently not applicable to the company. 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,"* which addresses accounting for restructuring and similar costs. SFAS 146 supersedes previous accounting guidance, principally EITF Issue 94-3, "*Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).*" In October 2002, the FASB issued SFAS 147, "*Accounting for Certain Financial Institutions—an amendment of SFAS 72 and 144 and FASB Interpretation 9,"* which applies to acquisitions of financial institutions.

NOTE 2: RECENT ACQUISITIONS AND INVESTMENTS

Sempra Energy Trading

During 2002, SET completed 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. On April 26, 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 Liverpool, England-based 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.

All of these entities were part of the former MG Metals Group, which had recently been acquired by Enron. Related to these acquisitions, the company recognized an extraordinary after-tax gain of $16 million and goodwill of $21 million, which is expected to be fully deductible for tax purposes.

In January 2003, SET purchased from CMS Energy's marketing and trading unit a substantial portion of its wholesale natural gas trading book for $17 million.

Sempra Energy Resources

On October 31, 2002, SER purchased a 305-megawatt, coal-fired power plant (renamed Twin Oaks Power) from Texas-New Mexico Power Company for $120 million. SER has a five-year contract to sell substantially all of the output of the 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. The wholly owned 1,250-megawatt Mesquite Power Plant near Phoenix, Arizona, is expected to commence commercial operations at 50-percent capacity in June 2003 and at full capacity in January 2004. This project has been financed through a synthetic lease agreement. Under this agreement, SER is reimbursed monthly for most project costs. Through December 31, 2002, SER had received $500 million under this facility. All amounts above $280 million require collateralization through purchases of U.S. Treasury obligations, which must at least equal 103 percent of the amount drawn. That collateralization was $228 million at December 31, 2002, and is included in "Investments" on the Consolidated Balance Sheets.

Sempra Energy International

SEI's Mexican subsidiaries Distribuidora de Gas Natural (DGN) de Mexicali, DGN de Chihuahua and DGN de La Laguna Durango built and operate natural gas distribution systems in Mexicali, Chihuahua and the La Laguna-Durango zone in north-central Mexico, respectively. At December 31, 2002, SEI owned interests of 60, 95 and 100 percent in the projects, respectively. Through December 31, 2002, DGN de Mexicali, DGN de Chihuahua and DGN de La Laguna Durango have made capital expenditures of $23 million, $57 million and $32 million, respectively. Total capital expenditures for these subsidiaries in 2002 were $15 million. On February 7, 2003, SEI completed its purchase of the remaining interests in DGN de Mexicali, DGN de Chihuahua, Transportadora de Gas Natural, a supplier of natural gas to the Presidente Juarez power plant in Rosarito, Baja California, and other subsidiaries.

NOTE 3. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Investments, other than housing partnerships, in which the company has an interest of twenty percent to fifty percent are accounted for under the equity method. The company has no investments where its ability to influence or control an investee differs from its ownership percentage. The company's pro rata shares of the subsidiaries' net assets are included under the caption "Investments" on the Consolidated Balance Sheets, and are adjusted for the company's share of each investee's earnings/losses, dividends and foreign currency translation effects. Earnings are recorded as equity earnings on the Statements of Consolidated Income within the caption "Other income — net." In accordance with EITF D-46, the company accounts for investments in housing partnerships made after May 18, 1995 according to the American Institute of Certified Public Accountants' Statement of Position 78-9 *"Accounting for Investments in Real Estate,"* which generally requires the use of the equity method unless the investor has virtually no influence over the partnership operating and financial policies. Investments in housing partnerships accounted for by the cost method are amortized over ten years based on the expected residual value. The company's investments in unconsolidated subsidiaries accounted for by the equity and cost methods are summarized as follows:

	Investments at December 31	
(dollars in millions)	**2002**	2001
Equity method investments:		
Chilquinta Energia (including Luz del Sur)	**$ 504**	$ 484
Sodigas Pampeana and Sodigas Sur	**17**	140
Elk Hills power project	**172**	133
El Dorado Energy	**73**	57
Sempra Energy Financial housing partnerships	**206**	228
Sempra Energy Financial synthetic fuel partnerships	**8**	9
Other	**—**	4
Total	**980**	1,055
Cost method investments:		
Sempra Energy Financial housing partnerships	**57**	81
Other	**3**	33
Total	**60**	114
Other:		
Mesquite Power Plant project (see Note 15)		
Collateralized U.S. Treasury obligations	**228**	—
Reimbursable project costs	**45**	—
Total	**273**	—
Total investments	**$1,313**	$1,169

For equity method investments, costs in excess of equity in net assets were $219 million and $233 million at December 31, 2002 and 2001, 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 has ceased in 2002. Costs in excess of the underlying equity in net assets will continue to be reviewed for impairment in accordance with Accounting Principles Board 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 Resources

In December 2000, SER obtained approvals from the appropriate state agencies to construct the Elk Hills Power Project (Elk Hills), a $395 million, 570-megawatt power plant near Bakersfield, California, which is anticipated to be completed by May 2003. Elk Hills is being developed in a joint venture with Occidental Energy Ventures Corporation (Occidental). Information concerning litigation with Occidental is provided in Note 15.

In 2000, El Dorado Energy, a 50/50 partnership between SER and Reliant Energy Power Generation, completed construction of a $280 million, 440-megawatt merchant power plant near Las Vegas, Nevada.

In December 2000, SER obtained approval from the appropriate state agencies to construct the Mesquite Power Plant. Located near Phoenix, Arizona, Mesquite Power is a $690 million, 1,250-megawatt project which will provide electricity to wholesale energy markets in the Southwest region. Ground was broken in September 2001. Commercial operations at 50-percent capacity are expected to commence in June 2003 and project completion is anticipated in January 2004. The project is being financed primarily via the synthetic lease agreement described in Note 15. Construction expenditures as of December 31, 2002 were $558 million. Financing under the synthetic lease in excess of $280 million requires collateralization through the purchase of U.S. Treasury obligations, which must at least equal 103 percent of the amount drawn. During 2002, the company purchased $228 million of U.S. Treasury obligations as collateral, which is included in "Investments" on the Consolidated Balance Sheets.

Sempra Energy International

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

In October 2000, SEI increased its existing investment in two Argentine natural gas utility holding companies (Sodigas Pampeana S.A. and Sodigas Sur S.A.) from 21.5 percent to 43 percent. Shortly after December 31, 2001, the Argentine peso, the functional currency of the companies' operations, began to float freely in the foreign exchange market. As a result of the decline in the value of the Argentine peso, SEI has reduced the carrying value of its investment by reducing shareholders' equity by $223 million, which is included in accumulated other comprehensive income (loss). These non-cash adjustments, which began at the end of 2001 and continued into the early part of 2002, did not affect net income, but did reduce comprehensive income and did increase 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) are continuing to adversely affect the operations of these Argentine utilities. On September 5, 2002, SEI filed for international arbitration under the 1994 Bilateral Investment Treaty between the United States and Argentina for recovery of the diminution of the value of its investments resulting from the government actions. SEI had its Request for Arbitration registered on December 6, 2002, and expects the International Center for Settlement of Investment Disputes to recognize the filing and set the matter for arbitration, but resolution is expected to take more than a year. Sempra Energy also has political-risk insurance that could recover a portion of the diminution.

SEI and the majority owner of the Argentine companies have an agreement whereby, under certain, specified circumstances, SEI could compel the majority owner to purchase SEI's interest or the majority owner could compel SEI to sell its interest to the majority owner.

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, including Puerto Rico and the Virgin Islands. These investments are accounted for in accordance with EITF Issue 94-1 *"Accounting for Tax Benefits Resulting from Investments in Affordable Housing Projects."* These investments are expected to provide income tax benefits (primarily from income tax credits) over 10-year periods. SEF also 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.

NOTE 4. SHORT-TERM BORROWINGS

At December 31, 2002, the company had available $2.25 billion in unused, committed lines of credit to provide liquidity and support commercial paper. As of December 31, 2002, $600 million of the lines was supporting commercial paper and variable-rate debt. Borrowings under these lines are subject to compliance with certain covenants. Under the most restrictive of these covenants Sempra Energy and its subsidiaries could have issued in excess of $3 billion of additional debt at December 31, 2002.

Committed Lines of Credit

At December 31, 2002, Global had a $950 million syndicated revolving line of credit guaranteed by Sempra Energy. The revolving credit commitment expires in September 2003, at which time outstanding borrowings may be converted to a one-year term loan. The agreement requires Sempra Energy to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 65 percent.

Borrowings under the agreement bear interest at rates varying with market rates and Sempra Energy's credit rating. Global's line of credit was unused at December 31, 2002, and is available to support commercial paper and variable-rate long-term debt. Global had $422 million and $705 million of commercial paper, guaranteed by Sempra Energy, outstanding at December 31, 2002 and 2001, respectively.

At December 31, 2002, the California Utilities had a combined revolving line of credit, under which each utility individually could borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement, which are available for general corporate purposes including support for commercial paper and variable-rate long-term debt, bear interest at rates varying with market rates and the individual borrowing utility's credit rating. This revolving credit commitment expires in May 2003, at which time the outstanding borrowings may be converted into a one-year term loan subject to any requisite regulatory approvals related to long-term debt. This agreement requires each utility to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 60 percent. The rights, obligations and covenants of each utility under the agreement are individual rather than joint with those of the other utility, and a default by one utility would not constitute a default by the other. These lines of credit were unused at December 31, 2002. At December 31, 2002, the California Utilities had no commercial paper outstanding.

At December 31, 2002, SER had a syndicated $400 million, three-year revolving line of credit, guaranteed by Sempra Energy, primarily to finance power plant and natural gas pipeline construction projects. 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, 2002, SER's outstanding borrowing under the line of credit, classified as long-term, was $100 million. See Note 5 for additional information on SER's borrowings. There were no loans outstanding under the line of credit at December 31, 2001.

At December 31, 2002, PE had a $500 million two-year revolving line of credit, guaranteed by Sempra Energy, for the purpose of providing loans to Global. The revolving credit commitment expires in April 2003, at which time the outstanding borrowings may be converted into a two-year term loan. Borrowings would be subject to mandatory repayment prior to the maturity date should PE's credit rating cease to be at least BBB- by Standard & Poor's (S&P) or SoCalGas' unsecured long-term credit ratings cease to be at least BBB by 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 and the amount of outstanding borrowings. PE's line of credit was unused at December 31, 2002 and December 31, 2001.

Uncommitted Lines of Credit

At December 31, 2002, SET had $690 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, 2002 and 2001, SET had $115 million and $120 million, respectively, in short-term borrowings, and $345 million and $167 million, respectively, of letters of credit outstanding against these lines.

The company's weighted average interest rate for short-term borrowings outstanding was 2.02% and 2.18%, at December 31, 2002 and 2001, respectively.

NOTE 5. LONG-TERM DEBT

(Dollars in millions)	December 31, 2002	2001
First-mortgage bonds		
5.75% November 15, 2003	**$ 100**	$ 100
4.8% October 1, 2012	**250**	—
6.8% June 1, 2015	**14**	14
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 (1.34% to 1.35% at December 31, 2002) September 1, 2020	**58**	58
5.85% June 1, 2021	**60**	60
7.375% March 1, 2023	**100**	100
7.5% June 15, 2023	**125**	125
6.875% November 1, 2025	**175**	175
6.4% and 7% December 1, 2027	**225**	225
8.5% April 1, 2022	**—**	10
7.625% June 15, 2002	**—**	28
6.875% August 15, 2002	**—**	100
Total	**1,386**	1,274
Other long-term debt		
5.60% Equity units May 17, 2007	**600**	—
Notes payable at variable rates after a fixed-to-floating rate swap (2.69% to 2.73% at December 31, 2002) July 1, 2004	**500**	500
7.95% Notes March 1, 2010	**500**	500
Rate-reduction bonds, 6.19% to 6.37% annually through 2007	**329**	395
6.95% Notes December 1, 2005	**300**	300
Debt incurred to acquire limited partnerships, secured by real estate, at 7.11% to 9.35% annually through 2009	**145**	187
5.9% June 1, 2014	**130**	130
SER line of credit at variable rates (3.073% at December 31, 2002) August 21, 2004	**100**	—
Employee Stock Ownership Plan		
Bonds at 7.375% November 1, 2014	**82**	82
Bonds at variable rates (1.92% at December 31, 2002) November 2014	**19**	46
5.67% January 15, 2003	**75**	75
Variable rates (2.00% at December 31, 2002) December 1, 2021	**60**	60
Variable rates (1.75% at December 31, 2002) July 1, 2021	**39**	39
6.75% March 1, 2023	**25**	25
6.375% May 14, 2006	**8**	8
Other variable-rate debt	**18**	27
Capitalized leases	**10**	14
Market value adjustments for interest rate swaps — net	**42**	22
Total	**4,368**	3,684
Less:		
Current portion of long-term debt	**281**	242
Unamortized discount on long-term debt	**4**	6
	285	248
Total	**$4,083**	$3,436

Excluding capital leases, which are described in Note 15, and market value adjustments for interest-rate swaps, maturities of long-term debt are $278 million in 2003, $745 million in 2004, $397 million in 2005, $100 million in 2006, $683 million in 2007 and $2.2 billion thereafter. Holders of variable-rate bonds may require the issuer to repurchase them prior to scheduled maturity. However, since repurchased bonds would be remarketed and funds for repurchase are provided by revolving lines of credit (which are generally renewed upon expiration and which are described in Note 4), it is assumed the bonds will be held to maturity for purposes of determining the maturities listed above. Interest rates on the $300 million and $500 million of notes maturing in 2005 and 2010, respectively, can vary with the company's credit ratings.

First-mortgage Bonds

The first-mortgage bonds were issued by the California Utilities and are secured by a lien on their respective utility plant. The California Utilities may issue additional first-mortgage bonds upon compliance with the provisions of their bond indentures, which require, among other things, the satisfaction of pro forma earnings-coverage tests on first-mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $2.7 billion of first-mortgage bonds at December 31, 2002.

During the first quarter of 2001, SDG&E remarketed $150 million of variable-rate first-mortgage bonds for a five-year term at a fixed rate of 7%. At SDG&E's option, the bonds may be remarketed at a fixed or floating rate at December 1, 2005, the expiration of the fixed term. In November 2001, SoCalGas called its $150 million 8.75% first-mortgage bonds at a premium of 3.59 percent. On December 11, 2001, SoCalGas entered into an interest-rate swap which effectively exchanged the fixed rate on its $175 million 6.875% first-mortgage bonds for a floating rate. On September 30, 2002, SoCalGas terminated the swap, receiving cash proceeds of $10 million, comprised of $4 million in accrued interest and a $6 million amortizable gain. Additional information is provided under "Interest-Rate Swaps" below. In June and July 2002, SDG&E paid off its $28 million 7.625% first-mortgage bonds and $10 million 8.5% first-mortgage bonds, respectively. In August 2002, SoCalGas paid off 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 not redeemable prior to maturity except through a make-whole mechanism. Proceeds from the bond sale have become part of the company's general funds to replenish amounts previously expended to refund and retire indebtedness, and for working capital and other general corporate purposes. These bonds were assigned ratings of A+ by the S&P rating agency, A1 by Moody's and AA by Fitch, Inc.

Callable Bonds

At the company's option, certain bonds may be called at a premium, including $157 million of variable-rate bonds that are callable at various dates in 2003. Of the company's remaining callable bonds, $860 million are callable in 2003, $25 million in 2004, $105 million in 2005 and $8 million in 2006.

Rate-Reduction Bonds

In December 1997, $658 million of rate-reduction bonds were issued on behalf of SDG&E at an average interest rate of 6.26 percent. These bonds were issued to facilitate the 10% rate reduction mandated by California's electric-restructuring law, which is described in Note 13. These bonds are being repaid over ten years by SDG&E's residential and small-commercial customers via 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.

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

Equity Units

In April and May of 2002, the company publicly offered and 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 (to be determined by the then-prevailing market prices). The company used the net proceeds of the offering to repay a portion of its short-term debt, including debt used to finance the capital expenditure program for Global.

Unsecured Long-term Debt

In February 2001, SDG&E remarketed $25 million of variable-rate unsecured bonds as 6.75 percent fixed-rate debt for a three-year term. At SDG&E's option, the bonds may be remarketed at a fixed or floating rate at February 29, 2004, the expiration of the fixed term. Various long-term obligations totaling $355 million are unsecured at December 31, 2002. In October 2001, SoCalGas repaid $120 million of 6.38 percent medium-term notes upon maturity. In June 2001, the company issued $500 million of three-year notes due July 1, 2004 at an interest rate of 6.8 percent. Sempra Energy has a fixed-to-floating rate swap on these notes. (See discussion under "Interest-Rate Swaps" below.)

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

In October 2002 SER borrowed $100 million on its $400 million line of credit. This loan is due August 2004 and bears a variable interest rate (3.073 percent at December 31, 2002).

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 on January 18, 2028.

In January 2003, the company issued $400 million of long-term 6% notes due February 2013. The bonds are not subject to a sinking fund and are not redeemable prior to maturity except through a make-whole mechanism. Proceeds were used to pay down commercial paper. These bonds were assigned ratings of A- by the S&P rating agency, Baa1 by Moody's and A by Fitch, Inc.

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

The Trust has covered substantially all of SoCalGas' employees and, effective January 1, 2000, employees of Sempra Energy and some of its unregulated affiliates. The Trust is used to fund part of the retirement savings plan. 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. In September 2001 and 2002, ESOP debt was reduced by $2.5 million and $0.9 million, respectively, when 40,000 shares and 17,000 shares, respectively, of company common stock were released from the Trust in order to fund the employer contribution to the company savings plan. Additional information on the company savings plan is included in Note 8. Interest on ESOP debt amounted to $7 million in 2002, $6 million in 2001 and $9 million in 2000. Dividends used for debt service amounted to $3 million each in 2002, 2001 and 2000.

Interest-Rate Swaps

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. At December 31, 2002, Sempra Energy has a fixed-to-floating-rate swap agreement on $500 million of underlying debt which matures in 2004 and effectively causes the interest rate on the debt to vary at a rate of LIBOR plus 1.329%. On December 11, 2001, SoCalGas executed a cancelable-call interest-rate swap, exchanging its fixed-rate obligation of 6.875% on its $175 million first-mortgage bonds for a floating rate of LIBOR plus 4 basis points. On September 30, 2002, SoCalGas terminated the swap, receiving cash proceeds of $10 million, comprised of $4 million in accrued interest and a $6 million amortizable gain. The company believes the remaining swap is fully effective in its purpose of converting the underlying debt's fixed rate to a floating rate and meets the criteria for accounting under the short-cut method defined in SFAS 133 for fair value hedges of debt instruments. Accordingly, market value adjustments to long-term debt of $20 million and $22 million were recorded at December 31, 2002 and 2001, respectively, to reflect, without affecting net income or other comprehensive income, the favorable/unfavorable economic consequences (as measured at December 31, 2002 and 2001) of having entered into the swap transactions. During 2002 and 2001, SDG&E had an interest-rate swap agreement that matured in 2002 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 income was a $1 million gain in 2002 and a $1 million loss in 2001. See additional discussion of interest-rate swaps in Note 10.

Foreign-Currency Hedges

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

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

Because the company does not hedge its net investment in foreign countries, it is susceptible to volatility in other comprehensive income, as occurred in the years ended December 31, 2002 and 2001 as a result of Argentina's decoupling its peso from the U.S. dollar as discussed in Note 3.

See additional discussion in Note 10.

Loans Due to Affiliates

In March 2001, SEI refinanced $160 million of long-term notes through its unconsolidated affiliate Chilquinta Energia Finance, LLC. At both December 31, 2002 and 2001, long-term notes payable to affiliates include $60 million at 6.47 percent due April 1, 2008 and $100 million at 6.62% due April 1, 2011. The loans are secured by SEI's investments in Energia and Luz.

Financial Covenants

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

NOTE 6. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2002, are as follows:

Project (Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20%	88%
Utility plant in service	$76	$222
Accumulated depreciation and amortization	$53	$134
Construction work in progress	$ 5	$ 12

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. Participants in each project must provide their own financing. The amounts specified above for SONGS include nuclear production, transmission and other facilities. Certain substation equipment at SONGS is wholly owned by the company.

SONGS Decommissioning

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

The company's share of decommissioning costs for the SONGS units is estimated to be $309 million in 2002 dollars, based on a 2001 cost study completed and filed with the CPUC in 2002. At this time, the cost study and resulting contributions are expected to be finalized and approved or disapproved by the CPUC in April of 2003. Cost studies are updated every three years and approved by the CPUC. The next such update is expected to occur 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 costs allowed by regulators. The amount accrued each year is currently being collected in rates. Currently, collections are authorized to continue until 2013, but may be extended upon request to the CPUC until 2022. The requested amount is considered sufficient to cover the company's share of future decommissioning costs. Payments to the nuclear decommissioning trusts (described below under "Nuclear Decommissioning Trusts") are expected to continue until sufficient funds have been collected to fully decommission SONGS, which is not expected to begin before 2022.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled and removed. Preparations have been made for the remaining major work to be performed in 2003 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 by 2008.

The amounts collected in rates are invested in externally managed trust funds (described below under "Nuclear Decommissioning Trusts"). The securities held by the trust are considered available for sale and the trust is shown on the Consolidated Balance Sheets at market value. These values reflect unrealized gains of $95 million and $122 million at December 31, 2002, and 2001, respectively, with the offsetting credit recorded to accumulated depreciation and amortization on the Consolidated Balance Sheets.

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

Nuclear Decommissioning Trusts

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

At December 31, 2002 and 2001, trust assets were allocated as follows (dollars in millions):

	Qualified Trust		Nonqualified Trust	
	2002	2001	**2002**	2001
Domestic equity	**$143**	$144	**$36**	$48
Foreign equity	**69**	76	**—**	—
Total equity	**212**	220	**36**	48
Total fixed income	**220**	225	**26**	33
Total	**$432**	$445	**$62**	$81

Decommissioning cost studies are conducted every three years to determine the appropriate level of contributions to be collected in utility-customer rates to ensure adequate funding at the decommissioning date. Customer contribution amounts are determined by estimates of after-tax investment returns, decommissioning costs and 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:

For the years ended December 31	2002	2001	2000
Statutory federal income tax rate	**35.0%**	35.0%	35.0%
Depreciation	**5.2**	5.9	6.7
State income taxes — net of federal income tax benefit	**7.0**	6.4	6.6
Tax credits	**(18.5)**	(13.7)	(13.0)
Income from unconsolidated foreign subsidiaries	**(2.0)**	(3.0)	(1.8)
Settlement of Internal Revenue Service audit	**(3.6)**	—	—
Other — net	**(2.9)**	(1.5)	5.1
Effective income tax rate	**20.2%**	29.1%	38.6%

The components of income tax expense are as follows:

(Dollars in millions)	2002	2001	2000
Current:			
Federal	**$ 195**	$ 36	$ (8)
State	**30**	60	(5)
Foreign	**13**	11	25
Total	**238**	107	12
Deferred:			
Federal	**(113)**	104	207
State	**31**	1	57
Foreign	**(5)**	7	(1)
Total	**(87)**	112	263
Deferred investment tax credits	**(5)**	(6)	(5)
Total income tax expense	**$ 146**	$213	$270

Accumulated deferred income taxes at December 31 consist of the following:

(Dollars in millions)	2002	2001
Deferred tax liabilities:		
Differences in financial and tax bases of utility plant	**$ 883**	$ 672
Balancing accounts and other regulatory assets	**305**	489
Partnership income	**45**	37
Other	**312**	279
Total deferred tax liabilities	**1,545**	1,477
Deferred tax assets:		
Investment tax credits	**62**	65
General business tax credit carryforward	**148**	24
Net operating losses of foreign entities	**89**	46
Postretirement benefits	**32**	36
Other deferred liabilities	**157**	174
Restructuring costs	**40**	40
Other	**247**	187
Total deferred tax assets	**775**	572
Net deferred income tax liability	**770**	905
Valuation allowance	**10**	12
Net deferred income tax liability	**$ 780**	$ 917

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

(Dollars in millions)	2002	2001
Current (asset) liability	**$ (20)**	$ 70
Noncurrent liability	**800**	847
Total	**$ 780**	$ 917

In connection with its affordable-housing investments, the company has $148 million of unused general business tax credits dating back to 1999. The cumulative credit carryforwards will expire between the years 2019 and 2022. The company fully expects to utilize the credits in future years. In addition, the company has $19 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 $275 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 $32 million of these losses, primarily by offsetting them against deferred tax liabilities with the same expiration pattern and country of jurisdiction.

The company has not provided for U.S. income taxes on foreign subsidiaries' undistributed earnings ($304 million at December 31, 2002), which 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.

NOTE 8. EMPLOYEE BENEFIT PLANS

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

Pension and Other Postretirement Benefits

The company sponsors several qualified and nonqualified pension plans and other postretirement benefit plans for its employees.

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

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

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

(Dollars in millions)	Pension Benefits 2002	Pension Benefits 2001	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001
WEIGHTED-AVERAGE ASSUMPTIONS AS OF DECEMBER 31:				
Discount rate	**6.50%**	7.25%	**6.50%**	7.25%
Expected return on plan assets	**8.00%**	8.00%	**7.80%**	7.85%
Rate of compensation increase	**4.50%**	5.00%	**4.50%**	5.00%
Cost trend of covered health-care charges	**—**	—	**7.00%(1)**	7.25%(1)
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	**$2,010**	$2,027	**$ 590**	$ 551
Service cost	**57**	49	**13**	11
Interest cost	**149**	141	**42**	41
Plan amendments	**51**	—	**(7)**	—
Actuarial (gain) loss	**197**	(27)	**191**	13
Curtailments	**—**	(7)	**—**	—
Settlements	**—**	1	**—**	—
Special termination benefits	**—**	13	**—**	—
Other	**13**	—	**—**	—
Benefits paid	**(187)**	(187)	**(32)**	(26)
Net obligation at December 31	**2,290**	2,010	**797**	590
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	**2,449**	2,910	**469**	515
Actual return on plan assets	**(281)**	(277)	**(50)**	(37)
Employer contributions	**3**	3	**22**	17
Benefits paid	**(187)**	(187)	**(32)**	(26)
Fair value of plan assets at December 31	**1,984**	2,449	**409**	469
Plan assets net of benefit obligation at December 31	**(306)**	439	**(388)**	(121)
Unrecognized net actuarial (gain) loss	**283**	(426)	**266**	(14)
Unrecognized prior service cost	**93**	49	**(14)**	(10)
Unrecognized net transition obligation	**1**	2	**—**	—
Net recorded asset (liability) at December 31	**$ 71**	$ 64	**$(136)**	$(145)

(1) Decreasing to ultimate trend of 6.50% in 2004.

The following table provides the amounts recognized on the Consolidated Balance Sheets (under 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)	**2002**	2001	**2002**	2001
Prepaid benefit cost	**$ 203**	$146	**$ —**	—
Accrued benefit cost	**(132)**	(82)	**(136)**	$(145)
Additional minimum liability	**(93)**	(18)	**—**	—
Intangible asset	**12**	3	**—**	—
Accumulated other comprehensive income, pretax	**81**	15	**—**	—
Net recorded asset (liability)	**$ 71**	$ 64	**$(136)**	$(145)

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

(Dollars in millions)	Pension Benefits			Other Postretirement Benefits		
Years ended December 31	**2002**	2001	2000	**2002**	2001	2000
Service cost	**$ 57**	$ 49	$ 41	**$ 13**	$ 11	$ 11
Interest cost	**149**	141	153	**42**	41	37
Expected return on assets	**(204)**	(219)	(239)	**(39)**	(39)	(37)
Amortization of:						
Transition obligation	**1**	1	1	**9**	10	11
Prior service cost	**7**	6	6	**(1)**	(1)	(2)
Actuarial gain	**(18)**	(39)	(55)	**—**	(3)	(8)
Special termination benefit	**—**	13	54	**—**	—	2
Curtailment cost (credit)	**—**	1	(2)	**—**	—	—
Settlement credit	**—**	(19)	(26)	**—**	—	—
Regulatory adjustment	**32**	51	18	**25**	30	26
Total net periodic benefit cost (income)	**$ 24**	$ (15)	$ (49)	**$ 49**	$ 49	$ 40

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

(Dollars in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health-care benefit cost	$ 9	$ (7)
Effect on the health-care component of the accumulated other postretirement benefit obligation	$119	$(96)

Except for one plan, all funded pension plans had plan assets in excess of accumulated benefit obligations. For that one plan, the projected benefit obligation and accumulated benefit obligation were $613 million and $575 million, respectively, as of December 31, 2002, and $448 million and $442 million, respectively, as of December 31, 2001.

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

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

Savings Plans

The company offers savings plans, administered by plan trustees, to all eligible employees. Eligibility to participate in the 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. 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 may not contain 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 $20 million in 2002, $17 million in 2001 and $15 million in 2000. The market value of company stock held by the savings plan was $533 million and $530 million at December 31, 2002 and 2001, respectively.

Employee Stock Ownership Plan

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

As the company makes contributions to the ESOP, the ESOP debt service is paid and shares are released in proportion to the total expected debt service. Compensation expense is charged and equity is credited for the market value of the shares released. Income tax deductions are based on the cost of the shares. Dividends on unallocated shares are used to pay debt service and are applied against the liability. The Trust held 2.6 million shares and 2.7 million shares of Sempra Energy common stock, with fair values of $61.0 million and $65.9 million, at December 31, 2002 and 2001, 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 2002 and 2001, 544,100 shares and 777,500 shares of restricted company stock, respectively, were awarded to key employees. The corresponding weighted average fair values of the shares granted were $24.77 and $23.37, respectively. There was no restricted company stock awarded in 2000. Subject to earlier forfeitures upon termination of employment, each award is scheduled to vest at the end of seven years, but is 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. Compensation expense for the issuance of restricted stock was approximately $7 million in 2002, $5 million in 2001 and $1 million in 2000.

In 2002, 2001 and 2000, Sempra Energy granted to officers and key employees 3,444,300, 2,934,800 and 4,339,000 stock options, respectively. The option price is equal to the market price of common stock at the date of grant. The options vest over a four-year period and do not include dividend equivalents. The stock options expire 10 years from the date of grant, subject to earlier expiration upon termination of employment. Compensation expense (or reduction thereof) for stock option grants (all associated with outstanding options with dividend equivalents, all of which were issued before 2000) and similar awards was ($2 million), $7 million and $14 million in 2002, 2001 and 2000, respectively.

As of December 31, 2002, 12,250,231 shares were authorized and available for future grants of restricted stock and/or stock options. In addition, on January 1 of each year, additional shares amounting to 1.5 percent of the outstanding shares of Sempra Energy common stock become available for grant.

The plans permit the granting of dividend equivalents, which provide grantees the opportunity to receive some or all of the cash dividends that would have been paid on the shares since the grant date. All grants 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 Accounting Principles Board Opinion 25, *"Accounting for Stock Issued to Employees."* 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, 1999	4,693,197	$21.96	1,844,079
Exercised	(399,875)	18.91	
Cancelled	(264,749)	23.39	
December 31, 2000	4,028,573	22.17	2,462,574
Exercised	(588,315)	20.92	
Cancelled	(119,911)	22.46	
December 31, 2001	3,320,347	22.38	2,508,328
Exercised	(172,358)	19.87	
Cancelled	(68,124)	24.03	
December 31, 2002	3,079,865	$22.48	2,777,590

On January 1, 2003, approximately two-thirds of the shares under options and the options exercisable ceased to have dividend equivalents, due to expiration or payment of the dividend equivalents.

	Shares Under Option	Weighted Average Exercise Price	Options Exercisable at December 31
OPTIONS WITHOUT DIVIDEND EQUIVALENTS			
December 31, 1999	3,953,005	$22.67	1,019,056
Granted	4,339,000	19.03	
Exercised	(329,313)	19.10	
Cancelled	(397,271)	25.07	
December 31, 2000	7,565,421	20.61	1,659,244
Granted	2,934,800	22.50	
Exercised	(421,633)	18.79	
Cancelled	(204,134)	23.59	
December 31, 2001	9,874,454	21.19	3,143,319
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

Additional information on options outstanding at December 31, 2002, is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Remaining Life	Weighted Average Exercise Price
Outstanding Options			
$14.29-$16.12	149,576	2.10	$15.99
$16.87-$22.65	9,930,929	6.98	$20.48
$23.45-$27.64	6,010,547	7.58	$25.26
	16,091,052	7.16	$22.22
Exercisable Options			
$14.29-$16.12	149,576		$15.99
$16.87-$22.65	5,287,704		$20.20
$23.45-$27.64	2,627,747		$25.93
	8,065,027		$21.99

The grant-date market value of each option grant (including dividend equivalents where applicable) was estimated using the modified Black-Scholes option-pricing model. Weighted average grant-date market values for options granted in 2002, 2001 and 2000 were $4.45, $4.29 and $3.07, respectively.

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

	2002	2001	2000
Stock price volatility	**22%**	24%	20%
Risk-free rate of return	**4.8%**	4.6%	6.8%
Annual dividend yield	**4.1%**	4.3%	5.4%
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, funds held in trust, notes receivable, dividends payable, short-term debt and customer deposits) approximate the carrying amounts. The following table provides the carrying amounts and fair values of the remaining financial instruments at December 31:

	2002		2001	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in limited partnerships	**$ 271**	**$ 346**	$ 317	$ 390
U.S. Treasury obligations	**$ 228**	**$ 228**	$ —	$ —
First-mortgage bonds	**$1,386**	**$1,452**	$1,274	$1,297
Notes payable	**1,300**	**1,424**	1,300	1,327
Equity units	**600**	**577**	—	—
SDG&E rate-reduction bonds	**329**	**357**	395	411
Debt incurred to acquire limited partnerships	**145**	**169**	187	206
Other long-term debt	**608**	**623**	528	545
Total long-term debt	**$4,368**	**$4,602**	$3,684	$3,786
Preferred stock of subsidiaries	**$ 204**	**$ 168**	$ 204	$ 162
Mandatorily redeemable trust preferred securities	**$ 200**	**$ 205**	$ 200	$ 214

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, which do not have readily determinable quoted market prices, were estimated based on the present value of the future cash flows, discounted at rates available for similar notes with comparable maturities. The fair values of the other long-term debt, preferred stock, mandatorily redeemable trust preferred securities and U.S. Treasury obligations were estimated based on quoted market prices for them or for similar issues.

Accounting for Derivative Instruments and Hedging Activities

SFAS 133 *"Accounting for Derivative Instruments and Hedging Activities,"* as amended by SFAS 138, *"Accounting for Certain Derivative Instruments and Certain Hedging Activities"* recognizes all derivatives as either assets or liabilities in the statement of financial position, measures those instruments at fair value and recognizes changes in the fair value of derivatives in earnings in the period of change unless the derivative qualifies as an effective hedge that offsets certain exposure. For related matters see discussion of EITF Issue 02-3 *"Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities"* and the rescission of EITF Issue 98-10 in Note 1.

The company utilizes derivative financial instruments to reduce its exposure to unfavorable changes in commodity prices, which are subject to significant and often volatile fluctuation. Derivative financial instruments include futures, forwards, swaps, options and long-term delivery contracts. These contracts allow the company to predict with greater certainty the effective prices to be received by the company and, in the case of the California Utilities, their customers. Since adoption of SFAS 133 on January 1, 2001, the company classifies its forward contracts as follows:

Normal Purchase and Sales: These contracts 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 at historical cost with gains and losses reflected in the Statements of Consolidated Income at the contract settlement date.

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 apply hedge accounting if certain criteria are met. When a contract no longer meets the requirements of SFAS 133, the unrealized gains and losses will be amortized over the remaining contract life.

In instances where hedge accounting is applied to derivatives, cash flow hedge accounting is elected and, accordingly, changes in fair values of the derivatives are included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. The effect on other comprehensive income for the years ended December 31, 2002 and 2001 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 following were recorded in the Consolidated Balance Sheets at December 31:

(Dollars in millions)	**2002**	2001
Fixed-priced contracts and other derivatives:		
Current assets	**$ 3**	$ 57
Noncurrent assets	**42**	27
Total	**45**	84
Current liabilities	**153**	171
Noncurrent liabilities	**813**	788
Total	**966**	959
Net liabilities	**$921**	$875
Regulatory assets and liabilities:		
Current regulatory assets	**151**	168
Noncurrent regulatory assets	**812**	784
Total	**963**	952
Regulatory balancing account liabilities	**—**	50
Current regulatory liabilities	**2**	4
Noncurrent regulatory liabilities	**—**	1
Total	**2**	55
Net regulatory assets	**$961**	$897

The remaining differences between net liabilities and regulatory assets were primarily due to market value adjustments of $42 million and $22 million at December 31, 2002 and 2001, respectively, to long-term debt 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.

$4 million of income in 2002 and $5 million of losses in 2001 were recorded in operating revenues and $1 million of income in 2002 and $1 million of losses in 2001 were recorded in “other income — net” in the Statements of Consolidated Income.

Market Risk

The company’s policy is to use derivative instruments to manage exposure to fluctuations in interest rates, foreign-currency exchange rates and 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 credit-worthy. The use of these instruments exposes the company to market and credit risk which may at times be concentrated with certain counterparties, although counterparty nonperformance is not anticipated.

Interest-Rate Risk Management

The company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing.

SDG&E had an interest-rate swap agreement that matured in December 2002 and effectively fixed the interest rate on $45 million of variable-rate underlying debt at 5.42 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 were recorded in the Statements of Consolidated Income. The effect on income was a $1 million gain and a $1 million loss for the years ended December 31, 2002 and 2001, respectively. Although this financial instrument did not meet the hedge accounting criteria of SFAS 133, it was effective in achieving the risk management objectives for which it was intended.

During 2002 the company also had two fixed-to-floating rate swaps. At December 31, 2002, it had a fixed-to-floating-rate swap agreement on $500 million of underlying debt which matures in 2004 and effectively causes the interest rate on the debt to vary at a rate of LIBOR plus 1.329%. SoCalGas had the other agreement, which was a cancelable-call interest-rate swap, exchanging its fixed-rate obligation of 6.875% on its $175 million first-mortgage bonds for a floating rate of LIBOR plus four basis points. On September 30, 2002, SoCalGas terminated the swap, receiving cash proceeds of $10 million, comprised of $4 million in accrued interest and a $6 million amortizable gain. The company believes both swaps have been fully effective in their purpose of converting the fixed rate stated in the debt to a floating rate and the swaps meet the criteria for accounting under the short-cut method defined in SFAS 133 for fair value hedges of debt instruments. Accordingly, market value adjustments of $20 million and $22 million (as discussed above) were added to long-term debt during the years ended December 31, 2002 and 2001, respectively, and no net gains or losses were recorded in income in respect to these swaps.

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 and, in the case of the California Utilities, the prices to be charged to their customers. See Note 1 for discussion of how these derivatives are classified under SFAS 133.

Energy Contracts

The California Utilities record natural gas and electric energy contracts in “Cost of natural gas distributed” and “Electric fuel and net purchased power,” respectively, in the Statements of

Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The company's trading operations include the net effects of its contracts in "other operating revenues." 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 a substantial portion of its revenue, as a principal, from market making and trading activities in natural gas, electricity, petroleum products, metals and other commodities, for which it quotes bid and asked prices to other market makers and end users. It also earns trading profits as a dealer by structuring and executing transactions that permit its counterparties to manage their risk profiles. In addition, it takes positions in markets based on the expectation of future market conditions. These positions include options, forwards, futures and swaps. These instruments 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. All of SET's derivatives were held for trading and marketing purposes. Sempra Energy guarantees many of SET's transactions.

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

Both SET and SES mark to market these derivative instruments on a daily basis, with gains and losses recognized in earnings. These instruments are included in the Consolidated Balance Sheets as trading assets or liabilities. Certain swaps and certain other instruments are entered into and closed out within the same period. SET and SES record net gains and losses on these derivative transactions in "other operating revenues" in the Statements of Consolidated Income.

The sections of Note 1 dealing with trading instruments, revenues and EITF Issue 02-3 provide information that pertains to this topic.

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, 2002 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, 2002 and 2001, expressed in terms of net replacement value. These exposures are net of $240 million of collateral in the form of customer margin and/or letters of credit.

(Dollars in millions) December 31,	**2002**	2001
Counterparty credit quality*		
SET:		
Commodity Exchanges	**$ 49**	$ 133
AAA	**69**	53
AA	**194**	105
A	**316**	577
BBB	**559**	476
Below investment grade	**504**	335
Total	**$1,691**	$1,679
SES:		
AA	**$ 8**	$ 4
A	**11**	18
BBB	**24**	7
Below investment grade and not rated	**86**	190
Total	**$ 129**	$ 219

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

Trading assets and trading liabilities are primarily carried at fair value. Trading assets at December 31, 2002 include commodity inventory, which is carried at fair value for inventory purchased on or before October 25, 2002. The majority of inventory purchased after October 25, 2002 (base metals) is carried at fair value and the remainder of the inventory purchased after October 25, 2002 is carried at average cost. On a limited basis, average cost includes the use of fair value for the quantity on hand at October 24, 2002, since historical cost data is not available for that portion. Furthermore, on January 1, 2003, all commodity inventory will be at lower of cost or market. SES has determined that the carrying amounts of its retail energy and wholesale energy contracts and instruments approximate fair value.

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

Based on quarterly measurements, the average fair values during 2002 for trading assets and liabilities approximate $3.0 billion and $2.3 billion, respectively. For 2001, the amounts were $3.0 billion and $2.2 billion, respectively.

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

December 31, (Dollars in millions)	2002	2001
TRADING ASSETS		
SET:		
Unrealized gains on swaps and forwards	**$1,226**	$1,635
OTC commodity options purchased	**480**	425
Due from trading counterparties	**1,279**	320
Due from commodity clearing organizations and clearing brokers	**49**	133
Commodities owned	**1,968**	165
Total	**5,002**	2,678
SES:		
Unrealized gains on swaps and forwards	**96**	149
Total	**96**	149
Less intercompany eliminations	**(34)**	(87)
Total	**$5,064**	$2,740
TRADING LIABILITIES		
SET:		
Unrealized losses on swaps and forwards	**$ 816**	$1,313
OTC commodity options written	**569**	290
Due to trading counterparties	**1,196**	162
Repurchase obligations	**1,511**	—
Total	**4,092**	1,765
SES:		
Unrealized losses on swaps and forwards	**6**	81
Total	**6**	81
Less intercompany eliminations	**(4)**	(53)
Total	**$4,094**	$1,793

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.

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

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

(Dollars in millions)	**2002**	2001
SET:		
Forwards and commodity swaps	**$ 87,621**	$34,567
Options purchased	**33,893**	21,552
Options written	**32,163**	18,265
Futures and exchange options	**27,838**	4,712
Total	**181,515**	79,096
SES:		
Forwards and commodity swaps	**1,742**	10
Options purchased	**—**	3
Options written	**1**	3
Futures and exchange options	**12**	9
Total	**1,755**	25
Less intercompany eliminations	**(1,380)**	(1,008)
Total	**$181,890**	$78,113

NOTE 11. PREFERRED STOCK OF SUBSIDIARIES

December 31, (Dollars in millions, except call price)	Call Price	**2002**	2001
Pacific Enterprises (not subject to mandatory redemption and without par value), authorized 15,000,000 shares:			
$4.75 Dividend, 200,000 shares outstanding	$100.00	**$ 20**	$ 20
$4.50 Dividend, 300,000 shares outstanding	$100.00	**30**	30
$4.40 Dividend, 100,000 shares outstanding	$101.50	**10**	10
$4.36 Dividend, 200,000 shares outstanding	$101.00	**20**	20
$4.75 Dividend, 253 shares outstanding	$101.00	**—**	—
Total		**80**	80
SoCalGas (not subject to mandatory redemption):			
$25 par value, authorized 1,000,000 shares:			
6% Series, 28,041 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:			
Not subject to mandatory redemption:			
$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 not subject to mandatory redemption		**79**	79
Subject to mandatory redemption:			
Without par value: $1.7625 Series, 1,000,000 shares outstanding	$ 25.00	**25**	25
Total		**$204**	$204

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

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

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share, plus any unpaid dividends. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are callable at December 31, 2002, except for the $1.7625 and $1.70 Series (callable in January and October 2003, respectively). The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares per year from 2003 to 2007; the remaining 750,000 shares must be redeemed in 2008.

Mandatorily Redeemable Trust Preferred Securities

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

NOTE 12. SHAREHOLDERS’ EQUITY AND EARNINGS PER SHARE

The only difference between basic and diluted earnings per share is the effect of common stock options. For 2002, 2001 and 2000, the effect of dilutive options was equivalent to an additional 1,059,000, 1,745,000, and 190,000 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 6.0 million shares, 2.1 million shares and 6.6 million shares for 2002, 2001 and 2000, respectively, for which the exercise price was greater than the average market price for common stock during the respective year.

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:

	2002	2001	2000
Common shares outstanding, January 1	**204,475,362**	201,927,524	237,408,051
Stock options exercised	**395,788**	1,009,948	729,188
Long-term incentive plan	**544,100**	777,500	—
Common stock investment plan*	**212,411**	761,154	—
Shares released from ESOP	**130,486**	134,645	125,848
Shares repurchased	**(674,400)**	(60,000)	(36,304,740)
Shares forfeited and other	**(172,175)**	(75,409)	(30,823)
Common shares outstanding, December 31	**204,911,572**	204,475,362	201,927,524

* In 2002 and 2001 participants in the Direct Stock Purchase Plan reinvested dividends and purchased newly issued shares. In 2000 open-market shares were used.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of the California Utilities' capital structure limits the amounts that are available for loans and dividends to the company from the California Utilities. At December 31, 2002, SDG&E and SoCalGas each could have provided $250 million to Sempra Energy (combined loans and dividends). At December 31, 2002, SDG&E and SoCalGas had loans to Sempra Energy of $250 million and $86 million, respectively.

Tender Offer

On February 25, 2000, the company completed a self-tender offer, purchasing 36.1 million shares of its outstanding common stock at $20 per share. In March 2000, the company's board of directors authorized the optional expenditure of up to $100 million to repurchase additional shares of common stock from time to time in the open market or in privately negotiated transactions. The company acquired 674,400 shares, 60,000 shares and 162,400 shares under this authorization in 2002, 2001 and 2000, 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 prices). The number of shares would range from 20 million to 24 million. The net proceeds of the offering were used primarily to repay a portion of the company's short-term debt, including debt used to finance the capital expenditure program for Global. The Equity Units are recorded as long-term debt in the Consolidated Balance Sheets. $61 million was charged to the common stock account in connection with the transaction.

NOTE 13. ELECTRIC INDUSTRY REGULATION

Background

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 AB 265, enacted in September 2000 and in effect through December 31, 2002. AB 265 imposed a ceiling of 6.5 cents/kWh on the cost of the electric commodity that SDG&E could pass on to its small-usage customers on a current basis, effective retroactive to June 1, 2000.

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). It increased to approximately $750 million in the first quarter of 2001 and decreased to $392 million at December 31, 2001 and $215 million at December 31, 2002 (included in current "regulatory balancing accounts—net").

In June 2001, representatives of California Governor Davis, the DWR, Sempra Energy and SDG&E entered into a Memorandum of Understanding (MOU) contemplating the implementation of a series of transactions and regulatory settlements and actions to resolve many of the issues affecting SDG&E and its customers arising out of the California energy crisis. During 2001, implementation of some of the MOU's provisions (with the rest no longer likely to be implemented) resulted in a partial reduction of the AB 265 undercollection (see above). In addition, the DWR's procurement of SDG&E's full net short position during 2001 and 2002 (see below) resulted in the cessation of growth in the AB 265 undercollection.

The Department of Water Resources and Power Procurement

In February 2001, through the passage of Assembly Bill 1, Chapter 4, Statutes of the 2001 First Extraordinary Session (AB X1), the DWR began to purchase power from generators and marketers and entered into long-term contracts for the purchase of a portion of the state's power requirements that is served by the IOUs. SDG&E and the DWR had an agreement under which the DWR purchased the net short supply for bundled SDG&E customers through December 31, 2002.

Since early 2001, the DWR has procured power for each of the California IOUs and the CPUC has established the allocation of the power and the related cost responsibility among the IOUs for that power. SDG&E's allocation results in its overall rates being comparable to those of the other two California electric IOUs, Southern California Edison (Edison) and Pacific Gas and Electric (PG&E). On December 17, 2002, the CPUC issued a decision allocating the cost of the DWR's revenue requirement for its 2003 power purchases. The decision pools the total fixed costs of the DWR's contracts and allocates these costs among the IOUs on the basis of the quantity of the energy supplied to each IOU from the contracts. Variable costs related to the energy supplied under each contract go to the IOU assigned each contract. This decision allocates $643 million to SDG&E and will be handled within existing utility rates. That amount is currently under additional review as the DWR revenue requirement was reduced when the IOUs began power procurement on January 1, 2003 (see discussion below).

The CPUC's objective was for the IOUs to take the procurement function back from the DWR by the beginning of 2003. On September 19, 2002, the CPUC issued a decision on how the power from the long-term contracts signed by the DWR should be allocated to the customers of each of the IOUs for purposes of determining the amount of additional power each utility is required to procure in 2003 and thereafter to fulfill its resource needs. The reasonableness of the IOUs' administration and dispatch of the allocated contracts will be reviewed by the CPUC in an annual proceeding. AB 57, signed by California Governor Davis on September 24, 2002, requires the CPUC to make this determination, and to establish procedures that will allow the IOUs to recover their electric procurement costs in a timely fashion without the need for retrospective reasonableness reviews. SDG&E believes that the return to the procurement function in accordance with AB 57 will have no adverse impact on its financial position or results of operations.

On August 22, 2002, the CPUC issued a decision that authorized the California IOUs to begin interim procurement of power to cover their net short energy requirements starting on January 1, 2003. The net short 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 power contracts allocated to the customers of each IOU by the DWR (see above). The IOUs are authorized to enter into contracts of up to five years for power from traditional sources, and up to 15 years for power from renewable sources. SDG&E is required to purchase approximately 10 percent of its customer requirements in 2003, based on the allocation of the DWR power approved by the CPUC on December 17, 2002.

On October 24, 2002, the CPUC issued a decision in the Electric Procurement proceeding that officially directs the resumption of the electric commodity procurement function by IOUs by January 1, 2003, and begins the implementation of recent legislation regarding procurement and renewables portfolio standards addressed in AB 57 and Senate Bill 1078. The decision established a process for review and approval of the utilities' updated 2003 and long-term (20-year) procurement plans. The CPUC approved SDG&E's 2003 procurement plan in December 2002 and approval of the long-term plan is expected during 2003. The CPUC has authorized the utilities to use derivatives to manage procurement risk and to acquire a variety of resource types including utility ownership, conventional generation, distributed generation, self generation, demand side resources, transmission and renewables. 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.

The Electric Procurement decision described above also directed each IOU to procure from renewable sources at least one percent of its 2003 total energy sales and an additional one percent of energy sales each year thereafter, until a 20-percent renewable resources portfolio is achieved by the year 2017. SDG&E has contracted to procure approximately four percent of its 2003 total energy sales from renewable sources and, pursuant to a December 2002 CPUC resolution, may “bank” or credit toward future years’ compliance any excess over its one-percent requirement.

The CPUC has placed a moratorium on the IOUs’ purchasing electricity from their affiliates for the earlier of two years or until the CPUC completes a rulemaking on this matter. SDG&E believes that this moratorium will have no adverse impact on its financial position or results of operations. During 2002, SDG&E’s purchases of electricity from its affiliate Sempra Energy Trading were less than one percent of total electricity purchases.

DWR Operating and Servicing Agreements

On December 19, 2002, the CPUC issued an Operating Order setting the terms by which the IOUs will administer the DWR contracts allocated to the customers of each of the utilities (see above). The DWR continues to bear the credit risk on the contracts and the IOUs have assumed the administrative burden of the contracts. The order requires the IOUs to take financial responsibility for acquiring natural gas supplies for the generation facilities that are subject to the DWR contracts.

SDG&E currently has pending an operating and servicing agreement signed by the DWR and SDG&E which, if approved by the CPUC, will supercede the CPUC’s operating order referred to above. The pending agreement will clearly delineate that the natural gas procurement and associated risk will continue to reside with the DWR.

Effect on Customer Rates

On December 19, 2002, the CPUC issued a decision denying SDG&E’s application for a rate surcharge to expedite recovery of the AB 265 undercollection. However, even at current rates and allocation of the resulting revenues between the DWR and SDG&E, the balance is expected to be completely recovered before the end of 2005. Also at issue is the ownership of certain power sale profits stemming from intermediate term purchase power contracts entered into by SDG&E during the early stages of California’s electric utility industry restructuring. The company believes that all profits associated with these contracts properly are for the benefit of SDG&E shareholders rather than customers, whereas the CPUC asserted that all the profits should accrue to the benefit of customers. Accordingly, SDG&E challenged the CPUC’s disallowance of profits from the contracts in both the California Court of Appeals and in Federal District Court.

These court proceedings have been held in abeyance pending the CPUC’s consideration of various other proposed settlements. On December 19, 2002, the CPUC rendered a 3-to-2 decision approving the June 2002 proposed settlement, previously described in the company’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, that divides the profits from these contracts, $199 million for SDG&E customers and $173 million for SDG&E shareholders. Of the $199 million in profits allocated to customers, $175 million had already been credited to ratepayers in 2001. The remaining $24 million was applied as a balancing account transfer that reduced the AB 265 balancing account in December 2002. The profits allocated to customers reduce SDG&E’s AB 265 undercollection, but do not adversely affect SDG&E’s financial position, liquidity or results of operations. The term of a commissioner who voted to approve the settlement has expired, and a new commissioner has been appointed. On January 29, 2003, the CPUC's Office of Ratepayer Advocates (ORA), the City of San Diego and the Utility Consumers' Action Network, a consumer-advocacy group, filed requests for a CPUC rehearing of the decision. On February 13, 2003, the company filed its opposition to rehearing of the decision. Parties requesting a rehearing and parties to any rehearing may also appeal the CPUC's final decision to the California appellate courts.

Direct Access

On March 21, 2002, the CPUC affirmed its decision prohibiting new direct access (DA) 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, effective January 1, 2003. This decision will have no effect on SDG&E's cash flows or results of operations, because any shortfall due to the cap on the exit fees will be funded by bundled customers in current rates. The CPUC is conducting further proceedings to determine whether, or to what extent, the interim cap should be revised after July 1, 2003. The CPUC's decisions concerning direct access affect SES' ability to enter into contracts to sell electricity in California.

SONGS

Operating costs of SONGS Units 2 and 3, including nuclear fuel and related financing costs, and incremental capital expenditures are recovered through the ICIP mechanism which allows SDG&E to receive approximately 4.4 cents per kilowatt-hour for SONGS generation. Any differences between these costs and the incentive price affect net income. For the year ended December 31, 2002, ICIP contributed $50 million to SDG&E's net income. The CPUC has rejected an administrative law judge's proposed decision to end ICIP prior to its December 31, 2003 scheduled expiration date. However, the CPUC has also denied the previously approved market-based pricing for SONGS beginning in 2004 and instead provided for traditional rate-making treatment, under which the SONGS ratebase would begin at zero, essentially eliminating earnings from SONGS until ratebase grows. The company has applied for rehearing of this decision.

FERC Actions

The FERC is investigating prices charged to buyers in the California PX and ISO markets by various electric suppliers. It 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 obliged 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. Such payments, if any, are not expected to be material to the company's financial position, results of operations or liquidity. In December 2002, a FERC administrative law judge's (ALJ) preliminary findings indicate that California owes power suppliers $1.2 billion (the $3 billion that California still owes energy companies less $1.8 billion the ALJ finds the energy companies overcharged California). California is seeking $8.9 billion in refunds and indicated it would appeal if the ALJ's findings are adopted. A FERC decision is not expected before the second half of 2003. More recently, FERC has launched an investigation into whether there was manipulation of short-term energy prices in the West that resulted in unjust and unreasonable long-term power sales contracts.

In addition, in February 2002 the CPUC and the California Electricity Oversight Board petitioned the FERC to determine that the long-term power contracts the DWR signed with energy companies during the height of the energy crisis do not provide just and reasonable rates, and to abrogate or reform the contracts. In April 2002, the FERC ordered hearings on the complaints. The order requires the complainants to satisfy a “heavy” burden of proof to support a revision of the contracts, and cited the FERC’s long-standing policy to recognize the sanctity of contracts, from which it has deviated only in “extreme circumstances.” In December 2002, a FERC administrative law judge held formal hearings and in January 2003 issued a partial, initial decision recommending that the validity of SER’s contract be determined under a “public interest” standard that requires the complainants to satisfy a significantly higher standard of review to invalidate the SER contract than would a just and reasonable standard. Final briefs were submitted to the full FERC commission later in January with respect to the public interest standard of review and the FERC has indicated that it expects to issue a final decision by March 2003.

Effect On Other Subsidiaries

At December 31, 2002, SET was due approximately $100 million from the ISO for which the company believes adequate reserves have been recorded. The collection of these receivables may depend on satisfactory resolution of the financial difficulties being experienced by the other IOUs as a result of the California electric industry situation described above.

NOTE 14. OTHER REGULATORY MATTERS

Gas Industry Restructuring

In January 1998, the CPUC released a staff report initiating a project to assess the current market and regulatory framework for California’s natural gas industry. In July 1999, after hearings, the CPUC issued a decision stating which natural gas regulatory changes it found most promising, encouraging parties to submit settlements addressing those changes, and providing for further hearings if necessary.

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

During 2002 the California Utilities filed a proposed implementation schedule and revised tariffs and rules required for implementation. However, protests of these compliance filings were filed, and the CPUC has not yet authorized implementation of most of the provisions of its decision. On December 30, 2002, the CPUC deferred acting on a plan to implement its decision.

The California Utilities believe that the implementation of the decision would make natural gas service more reliable, more efficient and better tailored to meet the needs of customers. The decision is not expected to adversely affect the California Utilities' earnings.

Cost of Service (COS) and Performance-Based Regulation (PBR)

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. The three areas that are eligible for PBR rewards 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. These incentive rewards are not included in the company's earnings before they are approved by the CPUC.

The COS and PBR cases for the California Utilities were filed on December 20, 2002. The filings outline projected expenses (excluding the commodity cost of electricity or natural gas consumed by customers or expenses for programs such as low-income assistance) and revenue requirements for 2004 and a formula for 2005 through 2008. SoCalGas' cost of service study proposes an increase in natural gas base rate revenues of $130 million. SDG&E's cost of service study proposes increases in electric and natural gas base rate revenues of $58.9 million and $21.6 million, respectively. The filings also requested a continuance and expansion of PBR in terms of earnings sharing and performance service standards that include both reward and penalty provisions related to customer satisfaction, employee safety and system reliability. The resulting new base rates are expected to be effective on January 1, 2004. A CPUC decision is expected in late 2003. The California Utilities' PBR mechanisms are in effect through December 31, 2003, at which time the mechanisms will be updated. That update will include, among other things, a reexamination of the California Utilities' reasonable costs of operation to be allowed in rates.

An October 10, 2001 decision denied the California Utilities' request to continue equal sharing between ratepayers and shareholders of the estimated savings for the PE/Enova merger as more fully discussed in Note 1 and, instead, ordered that all of the estimated 2003 merger savings go to ratepayers. This decision will adversely affect the California Utilities' 2003 net income by $35 million.

In August 2002, the CPUC issued a resolution approving SDG&E's 2000 PBR report. The resolution approved SDG&E's request for a total net reward of $11.7 million (pretax), as well as SDG&E's actual 2000 rate of return (applicable only to electric distribution and natural gas transportation) of 8.74 percent, which is below the authorized 8.75 percent. This results in no sharing of earnings in 2000 under the PBR sharing mechanism. The financial results herein include the reward during the third quarter of 2002.

During 2002, SDG&E filed its 2001 PBR report with the CPUC. Based on the results against the performance indicator benchmarks, SDG&E requested a total net reward of $12.2 million.

On January 16, 2003, the CPUC issued a resolution approving SoCalGas' report on its PBR results for 2000. The resolution approved SoCalGas' calculation of the amount that should be retained by shareholders. The resolution also approved SoCalGas' request for an $80,000 reward for employee safety results. SoCalGas is not eligible for any other rewards and was not found by the resolution to owe any penalties.

During 2002, SoCalGas filed its 2001 PBR report with the CPUC. Based on the results against the performance indicator benchmarks, SoCalGas requested a total net reward of $0.5 million.

These proceedings do not encompass electric transmission issues. By the end of February 2003, SDG&E will file an electric transmission rate request with the FERC, updating its ratebase and its revenue requirement for operating and maintenance costs.

Natural Gas Procurement PBR

SDG&E has a Natural Gas Procurement PBR mechanism that allows SDG&E to receive a share of the savings it achieves by buying natural gas for customers below a monthly benchmark. SDG&E's request for a reward of $6.7 million for the PBR natural gas procurement period ended July 31, 2001 (Year 8) was approved by the CPUC on January 30, 2003. As part of the reward calculation is based on California-Arizona natural gas border price indices, the decision reserved the right to revise the reward in the future, depending on the outcome of the CPUC's border price investigation (see below) and the FERC's investigation into alleged energy price manipulation (see Note 13 above). In October 2002, SDG&E filed its Year 9 report for the PBR natural gas procurement period ended July 31, 2002, reporting a $1.4 million disallowance, which was recorded during the three-month period ended September 30, 2002. SDG&E also filed an application on October 31, 2002, seeking to modify and extend the Natural Gas PBR mechanism beyond Year 10, which ends July 31, 2003.

Gas Cost Incentive Mechanism (GCIM)

SoCalGas' 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 all savings within a tolerance band below the benchmark price. The costs or savings outside the tolerance band are shared between customers and shareholders. The CPUC approved the use of natural gas futures for managing risk associated with the GCIM. SoCalGas enters into natural gas futures contracts in the open market to mitigate risk and better manage natural gas costs.

On December 17, 2002, the CPUC issued its final decision in the GCIM Year 6 Phase 2 proceeding, approving, with modifications, a settlement agreement among SoCalGas, the CPUC's ORA and The Utility Reform Network, a consumer-advocacy group, and extending the GCIM mechanism to Year 7 and beyond.

SoCalGas has requested that the CPUC approve rewards of $30.8 million and $17.4 million for GCIM Years 7 and 8, respectively. CPUC approval of these rewards is expected in 2003, subject to possible future adjustment as a result of its investigation into the run-up in California border natural gas prices during the winter of 2000-2001 (discussed below). In the past shareholder rewards associated with the GCIM had been recorded to SoCalGas' Purchased Gas Balancing Account after the close of the GCIM period covering the utility's natural gas supply operations for the twelve months ended March 31. In June 2002, the CPUC issued a decision allowing SoCalGas to recover its GCIM earnings through its monthly core procurement filing beginning January 1, 2003. These awards are not included in SoCalGas' earnings until approved by the CPUC.

Demand Side Management and Energy Efficiency Awards

Since the 1990s, the IOUs have been eligible to earn awards for implementing and/or administering energy-conservation programs. The California Utilities have offered these programs to customers and have consistently achieved significant earnings therefrom. Beginning in 2002, earnings for non-low-income energy-efficiency programs were eliminated; however, awards related to DSM and low-income energy-efficiency programs may still be requested.

SoCalGas has outstanding before the CPUC applications to recover shareholder rewards earned for performance under the DSM programs for 1995 through 2001. Reward requests in these applications total $9.1 million.

SDG&E has outstanding before the CPUC applications to recover shareholder rewards earned for performance under the DSM programs for 1995 through 2001. Reward requests in these applications total $35.5 million.

A CPUC Administrative Law Judge has scheduled a pre-hearing conference to review the IOUs' DSM programs. The review may include reanalyzing the uncollected portion of past rewards earned by IOUs (which have not been included in the California Utilities' income), and potentially recompute the amount of the DSM rewards. The California Utilities have opposed such a recalculation. The issue is still pending before the CPUC.

Pending Incentive Awards

At December 31, 2002, 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
PBR	$ 0.5	$12.2	$ 12.7
Natural gas procurement	48.2	6.7	54.9
DSM	9.1	35.5	44.6
Total	$57.8	$54.4	$112.2

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. These rates will continue to be effective until the next periodic review by the CPUC unless market interest-rate changes are large enough to trigger an automatic adjustment prior thereto, which last occurred in October 2002 and adjusted rates downward from the previous 11.6 percent (ROE) and 9.49 percent (ROR) to the current levels. This change results in an annual revenue requirement decrease of $10.5 million.

Effective January 1, 2003, SDG&E's authorized rate of return on equity is 10.9 percent (increased from 10.6 percent) for SDG&E's electric distribution and natural gas businesses. This change results in an annual revenue requirement increase of $2.4 million ($1.9 million electric and $0.5 million natural gas) and increases SDG&E's overall rate of return from 8.75 percent to 8.77 percent. These rates remain in effect through 2003. The electric-transmission cost of capital is determined under a separate FERC proceeding.

Border Price Investigation

On November 21, 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California-Arizona (CA-AZ) border during the period of March 2000 through May 2001. The CPUC intends to examine the possible reasons for and issues potentially related to the elevated border prices that affected California consumers during this period.

The California Utilities are included among the respondents to the investigation. If the investigation determines that the conduct of any respondent contributed to the natural gas price spikes at the CA-AZ border during this period, the CPUC may modify the respondent's applicable natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, or order the respondent to issue a refund to ratepayers to offset the higher rates paid. The California Utilities are fully cooperating with the CPUC in the investigation and believe that the CPUC will ultimately determine that they were not responsible for the high border prices during this period.

Biennial Cost Allocation Proceeding (BCAP)

The BCAP determines the allocation of authorized costs between customer classes and the rates and rate design applicable to such classes for natural gas transportation service. The BCAP adjusts SoCalGas' rates to reflect variances in customer demand as compared to the adopted forecasts previously used in establishing customer natural gas transportation rates. The mechanism in effect through the end of 2002 largely eliminated the effect on SoCalGas' income of variances in customer demand and natural gas transportation costs. SDG&E filed its 2003 BCAP on October 5, 2001 and SoCalGas filed its 2003 BCAP on September 21, 2001. In February 2003, a CPUC Administrative Law Judge granted a motion to defer the BCAP. As a result of that ruling, the California Utilities must submit an amended application by September 2003, with new rates scheduled to be implemented by September 2004. On December 5, 2002, the CPUC issued a decision approving 100 percent balancing account protection for all core and noncore transportation costs, effective in 2003.

Nuclear Decommissioning Trusts

On June 17, 2002, SDG&E amended its March 21, 2002 joint application with Edison, requesting the CPUC to set contribution levels for the SONGS nuclear decommissioning trust funds. SDG&E requested a rate increase to cover its share of projected increased decommissioning costs for SONGS. If approved, the current annual contribution to SDG&E's trust funds, which is recovered in rates, would increase to $11.5 million annually from $4.9 million. Prior to August 1999, SDG&E's annual contribution had been $22 million.

Utility Integration

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

In a related development, an August 2002 CPUC interim decision denied a request by the California Utilities to combine their natural gas procurement activities at this time, pending completion of the CPUC's Border Price Investigation referred to above.

CPUC Investigation of Energy-Utility Holding Companies

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. Among the matters to be considered in the investigation are utility dividend policies and practices and obligations of the holding companies to provide financial support for utility operations under the agreements with the CPUC permitting the formation of the holding companies.

On January 11, 2002, the CPUC issued a decision to clarify under what circumstances, if any, a holding company would be required to provide financial support to its utility subsidiaries. The CPUC broadly determined that it would require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to cover their utility subsidiaries' capital requirements, as the IOUs have previously acknowledged in connection with the holding companies' formations. On January 14, 2002, the CPUC ruled on jurisdictional issues, deciding that the CPUC had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed. The company's request for rehearing on the issues was denied by the CPUC and the company subsequently filed appeals in the California Court of Appeal, which are still pending.

Valley-Rainbow Interconnect

On December 19, 2002, the CPUC issued a decision finding that the Valley-Rainbow Interconnect, a proposed 500-kv transmission line connecting SDG&E's and Edison's transmission systems, is not needed to meet SDG&E's projected resource needs within a planning horizon that the CPUC deemed appropriate (five years). If it chooses to, SDG&E can refile at a later date. In January 2003, SDG&E and the ISO filed applications for rehearing of the decision. If this project is abandoned SDG&E plans to seek recovery of its costs ($20 million through December 31, 2002) in a FERC filing to be made in February 2003.

NOTE 15. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

The California Utilities buy natural gas under short-term and long-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. 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 for firm pipeline capacity under contracts with pipeline companies that expire at various dates through 2006.

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

At December 31, 2002, the future minimum payments under natural gas contracts were:

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2003	$210	$687	$ 897
2004	214	3	217
2005	204	3	207
2006	117	2	119
2007	14	2	16
Thereafter	157	—	157
Total minimum payments	$916	$697	$1,613

Total payments under natural gas contracts were $1.4 billion in 2002, $2.6 billion in 2001, and $1.6 billion in 2000.

Purchased-Power Contracts

On January 17, 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 purchases SDG&E's full net short position (the power needed by SDG&E's customers, other than that provided by SDG&E's nuclear generating facilities or its previously existing 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. For additional discussion of this matter see Note 13.

For 2003, SDG&E expects to receive 43 percent of its customer power requirement from DWR allocations. Of the remaining requirements that SDG&E must provide, SONGS will account for 21 percent, long-term contracts for 26 percent and spot market purchases for 10 percent. As of January 2003, SDG&E has approximately 90 percent of its electric power requirements met by a combination of long-term contracts, DWR-allocated contracts and its share of nuclear generating facilities. The contracts expire on various dates between 2003 and 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 late 2000, SDG&E entered into additional contracts to serve customers instead of buying all of its power from the PX. These contracts expire in 2003. In addition, during 2002 SDG&E entered into contracts which will provide approximately four percent of its 2003 total energy sales from renewable sources. These contracts expire from 2008 through 2018.

At December 31, 2002, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2003	$ 257
2004	227
2005	228
2006	224
2007	213
Thereafter	2,285
Total minimum payments	$3,434

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Total payments under the contracts were $235 million in 2002, $512 million in 2001 and $257 million in 2000.

Leases

The company has leases (primarily operating) on real and personal property expiring at various dates from 2003 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 7 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company. The company also has long-term capital leases on real property. Property, plant and equipment included $35 million at both December 31, 2002 and 2001, related to these leases. The associated accumulated amortization was $21 million and $18 million, respectively. SDG&E terminated its capital lease agreement for nuclear fuel in mid-2001 and now owns its nuclear fuel.

At December 31, 2002, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

(Dollars in millions)	Operating Leases	Capitalized Leases
2003	$ 94	$ 3
2004	101	3
2005	104	3
2006	103	1
2007	105	1
Thereafter	1,385	1
Total future rental commitments	$1,892	12
Imputed interest (7% to 10%)		(2)
Net commitments		$10

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 $42 million at December 31, 2002. These leases are included in the above table.

Rent expense for operating leases totaled $90 million in 2002, $92 million in 2001 and $102 million in 2000. Depreciation expense for capitalized leases is included in depreciation on the Consolidated Statements of Income.

Construction Projects

In October 2001, Sempra Energy announced plans to develop a major new liquefied natural gas (LNG) receiving terminal to bring natural gas supplies into northwestern Mexico and southern California. SEI initially purchased a 300-acre site on the Pacific Coast, north of Ensenada, Baja California, Mexico for the terminal for a purchase price of $19.7 million. Subsequently, it purchased additional land for the terminal for $2.6 million. As currently planned, the plant would have a send-out capacity of approximately 1 billion cubic feet per day of natural gas through a new 40-mile pipeline between the terminal and existing pipelines in the San Diego/Baja California border area. The project is currently estimated to cost $600 million and to commence commercial operations in 2007.

In February 2003, Sempra LNG Corp., a newly created subsidiary of Global, announced an agreement to acquire the proposed Hackberry, La., LNG project from a subsidiary of Dynegy, Inc. Sempra LNG Corp. initially will pay Dynegy $20 million, with additional payments contingent on the performance of the project. The project has received preliminary approval from the FERC and expects a final decision later this year. If the project is approved, Sempra LNG Corp. intends to build an LNG receiving facility capable of processing up to 1.5 billion cubic feet per day of natural gas. The total cost of the project is expected to be about $700 million. The project could begin commercial operations as early as 2007.

In February 2001, the company announced plans to construct Termoelectrica de Mexicali, a $350 million, 600-megawatt power plant near Mexicali, Mexico. Fuel for the plant will be supplied via the newly constructed pipeline from Arizona to Tijuana referred to below. It is anticipated that the electricity produced by the plant will be available for markets in California, Arizona and Mexico via a newly constructed 230,000-volt transmission line. Construction of the power plant began in the second half of 2001. $308 million has been invested in the project, which is scheduled for completion by mid-2003. SER has approximately $8 million of commitments remaining in the project at December 31, 2002.

In December 2000, SER obtained approvals from the appropriate state agencies to construct the Elk Hills Power Project, a $395 million 570-megawatt power plant near Bakersfield, California. Elk Hills is being developed in a 50/50 joint venture with Occidental. As of December 31, 2002, SER has invested $172 million in the project and has commitments of approximately $15 million. The project is anticipated to be completed in May 2003. Information concerning related litigation with Occidental is provided below.

In December 2000, SER obtained approval from the appropriate state agencies to construct the Mesquite Power Plant (Mesquite Power). Located near Phoenix, Arizona, Mesquite Power is a $690 million, 1,250-megawatt project which will provide electricity to wholesale energy markets in the Southwest. Construction began in September 2001, commercial operations at 50-percent capacity are expected to commence in June 2003 and project completion is anticipated for January 2004. Expenditures as of December 31, 2002 are $558 million and SER has commitments of $70 million related to this project. Most project expenditures are financed through a synthetic lease agreement. Financing under the synthetic lease in excess of $280 million requires 103 percent collateralization through the purchase of U.S. Treasury obligations in similar amounts. As of December 31, 2002, the company had purchased $228 million of U.S. Treasury obligations as collateral, which is included in investments on the Consolidated Balance Sheets.

SER, as construction agent for the lessor, is responsible for completing construction in a timely manner. Upon completion of Mesquite Power, SER is required to make lease payments to the lessor in an amount sufficient to provide a specified return to the investors. In 2005, SER has the option to extend the lease at fair market value, purchase the project at a fixed amount, or act as remarketing agent for the lessor to sell the project. If SER elects the remarketing option, it may be required to pay the lessor up to 85 percent of the project cost if the proceeds from remarketing are insufficient to repay the lessor's investors. The lease is guaranteed by Sempra Energy, and the availability of additional financing is conditioned upon Sempra Energy's continuing to have credit ratings of at least BBB- by S&P or Baa3 by Moody's. The lease also requires Sempra Energy to maintain a debt-to-total capitalization ratio, (as defined in the lease), of not to exceed 65 percent. As a synthetic lease, neither the plant asset nor the related liability is included on the Consolidated Balance Sheets. If they were, property, plant and equipment and long-term debt would each have been increased by $545 million at December 31, 2002, reflecting reimbursements for costs incurred on the project, including costs subject to the collateralization requirements noted above. The company is currently reviewing the synthetic lease to determine the application of FASB Interpretation 46 (FIN 46), *"Consolidation of Variable Interest Entities"* related to the Mesquite Power Plant. Under FIN 46, the company would be required to increase property, plant and equipment and long-term debt by the total costs incurred and subject to collateralization requirements under the synthetic lease, as noted above. See further discussion of FIN 46 in Note 1.

In addition, as of December 31, 2002, SER has commitments of $73 million related to two natural gas turbines for use in future power plant development.

In the third quarter of 2002, SEI completed construction of the 140-mile Gasoducto Bajanorte Pipeline that connects the Rosarito Pipeline south of Tijuana, Mexico, with a pipeline being built by PG&E Corporation that will connect 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 Termoelectrica de Mexicali power plant discussed above. Capacity on the pipeline is fully subscribed. Total capital expenditures of $124 million have been made by SEI through December 31, 2002.

Other Commitments and Contingencies

In May 2001, SER entered into a ten-year agreement with the DWR to supply up to 1,900 megawatts of power to the state. SER may, but is not obligated to, deliver most of this electricity from its projected 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. The profits from the sales to the DWR are significant to the company's ability to increase its earnings. Subsequent to the state's signing of this contract and electricity-supply contracts with other vendors, various state officials have contended that the rates called for by the contracts are too high. These rates substantially exceed current spot-market prices for electricity, but are substantially lower than those prevailing at the time the contracts were signed. This contract is discussed further under "Litigation."

In February 2002, the CPUC and the California Electricity Oversight Board petitioned the FERC to determine that the contracts do not provide just and reasonable rates, and to abrogate or reform the contracts. On April 24, 2002, the FERC ordered hearings on the complaints. The order requires the complainants to satisfy a "heavy" burden of proof to support a revision of the contracts, and cited the FERC's long-standing policy to recognize the sanctity of contracts, from which it has deviated only in "extreme circumstances." In December 2002, a FERC administrative law judge held formal hearings and in January 2003 issued a partial, initial decision recommending that the validity of SER's contract be determined under a "public interest" standard that requires the complainants to satisfy a significantly higher standard of review to invalidate the SER contract than would a just and reasonable standard. Hearings began in December 2002 and settlement negotiations are ongoing. The FERC has indicated that it expects to issue a final decision by March 2003. The company believes that the contract prices were fair, but had been discussing (and continues to be willing to further discuss) with the DWR changing certain aspects of the contract (which would not affect the long-term profitability) in a manner mutually beneficial to SER and the state.

On October 31, 2002, SER completed the acquisition of Twin Oaks Power from Texas-New Mexico Power Company for $120 million. Located near Bremond, Texas, Twin Oaks Power is a 305-megawatt lignite-fired power plant which provides electricity under a 5-year offtake agreement expiring in September 2007. 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. At December 31, 2002, SER's future minimum payments under the lignite coal agreement were $28 million for 2003, $27 million for 2004, $27 million for 2005, $23 million for 2006, $23 million for 2007 and $310 million thereafter. The minimum payments have been adjusted for allowed shortfalls and 90 percent minimum contract requirements under the contract.

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, or to what extent, the interim cap should be revised after July 1, 2003. The CPUC's decisions concerning direct access affect SES' ability to enter into contracts to sell electricity in California.

Environmental Issues

The company's operations are subject to federal, state and local environmental laws and regulations governing hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. Most of the environmental issues faced by the company occur at the California Utilities. However, as SER constructs new power plants, additional environmental issues will arise requiring the company's attention. As applicable, appropriate and relevant, these laws and regulations require that the company investigate and remediate the effects of the release or disposal of materials at sites associated with past and present operations, including sites at which the company has been identified as a Potentially Responsible Party (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 $8 million in 2002, $6 million in 2001 and $4 million in 2000. 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 assurance 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 (25 completed as of December 31, 2002 and 20 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). Through December 31, 2003, the SONGS mitigation costs are recovered through the ICIP mechanism.

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, 2002, the company's accrued liability for environmental matters was $57.8 million, of which $42.7 million related to manufactured-gas sites, $12.1 million to cleanup at SDG&E's former fossil-fueled power plants, $2.3 million to waste-disposal sites used by the company (which has been identified as a PRP) and $0.7 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 four years. The accruals for SDG&E's former fossil-fueled power plants are expected to be paid ratably over the next three years.

Nuclear Insurance

SDG&E and the other co-owners of SONGS have insurance to respond to any nuclear liability claims related to SONGS. The insurance policy provides $200 million in coverage, which is the maximum amount available. In addition to this primary financial protection, the Price-Anderson Act provides for up to $9.25 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 $200 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 $176 million under the Price-Anderson Act. SDG&E's share would be $36 million unless default occurs by any other SONGS co-owner. In the event the secondary financial protection limit is 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 co-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 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. Coverage is also provided for the cost of replacement power, which includes indemnity payments for up to three years, after a waiting period of 12 weeks. 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 $7.6 million.

Both the nuclear liability and property insurance programs include industry aggregate limits for SONGS losses resulting from acts of terrorism.

Department Of Energy Decommissioning

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

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. 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.

Litigation

Lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek class-action certification and damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso Energy Corp. and several of its affiliates, unlawfully sought to control and have manipulated natural gas and electricity markets. On October 16, 2002, the assigned San Diego Superior Court judge ruled that the case can proceed with discovery and that the California courts, rather than the FERC, have jurisdiction in the case. This was a preliminary ruling and not a ruling on the merits or facts of the case. Northern California cases, which only name El Paso as a defendant, are scheduled for trial in September 2003 and the remainder of the cases are set for trial in January 2004. During the fourth quarter of 2002, additional similar lawsuits have been filed in various jurisdictions.

Various 2000 lawsuits, which seek class-action certification, allege that certain company subsidiaries unlawfully manipulated the electric-energy market. These lawsuits were consolidated in San Diego Superior Court by order of the Judicial Council, but have recently been removed to Federal Court where motions to remand are pending. Similar, subsequent lawsuits are expected to be consolidated with the existing matters in San Diego.

SER is a defendant in an action brought by Occidental Energy Ventures Corporation with respect to the Elk Hills power project being jointly developed by the two companies. Occidental alleges that SER breached the joint venture agreement by not providing that Occidental would be a party to the contract with the DWR or receiving its share of the proceeds from providing the DWR with power from Elk Hills under the contract. The court has ordered that the agreement requires the matter be arbitrated in accordance with the agreement.

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's office requested a rehearing, which the FERC denied. The California Attorney General has filed an appeal in the 9th Circuit.

Except for the matters referred to above, neither the company nor its subsidiaries are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

Management believes the above allegations are without merit and will not have a material adverse effect on the company's financial condition or results of operations.

Other Legal Proceedings

In connection with its investigation into California energy prices, in May 2002 the FERC ordered all energy companies engaged in electric energy trading activities to state whether they had engaged in "death star," "load shift," "wheel out," "ricochet," "inc-ing load" and various other specific trading activities as described in memos prepared by attorneys retained by Enron Corporation and in which it was asserted that Enron was manipulating or "gaming" the California energy markets. In response to the inquiry, Sempra Energy's electricity trading subsidiaries have denied using any of these strategies. SDG&E did disclose and explain a single de minimus 100-mW transaction for the export of electricity out of California. In response to a related FERC inquiry regarding natural gas trading, SDG&E and SoCalGas have also denied engaging in "wash" or "round trip" trading activities. The companies are also cooperating with the FERC and other governmental agencies and officials in their various investigations of the California energy markets.

In October 2002, the FERC also requested the largest North American natural gas marketers in 2001 to submit information regarding natural gas trading data provided by these marketers to energy trade publications in 2000 and 2001. During this period individual employees at SET received unsolicited information requests from trade publications, many of which were telephone inquiries seeking an immediate telephonic response. SET has advised the FERC and the Commodity Futures Trading Commission (CFTC) that, out of several hundred communications during the relevant period, prices were inaccurately reported by perhaps $.01 to $.02 per mmbtu on a handful of occasions involving an area in the Rocky Mountain region. No records of these telephone conversations exist. SET has also advised the FERC that it has found no instances involving inaccurate written information provided by SET to trade publications and is cooperating with the CFTC's inquiries about the matter.

On May 28, 2002, SER filed a complaint for declaratory judgment in San Diego Superior Court regarding its contract with the DWR. In addition to other relief, SER is seeking a binding declaration from the court that, contrary to DWR's stated position, SER is meeting the terms of the agreement and that DWR is obligated to take delivery of and pay for wholesale electric power, as provided for under the agreement. In response to SER's complaint for a declaratory judgment, on July 2, 2002, the DWR filed a cross-complaint against SER, seeking to void the 10-year energy-supply contract by alleging that SER misrepresented its intentions regarding the Elk Hills Power Plant as well as the other plants currently under construction. The DWR continues to accept all scheduled power from SER and has made all payments for such power. The construction of the Elk Hills Power Plant is on schedule to begin operating in the spring of 2003. The DWR has stated its belief that the contract requires SER to build power plants to supply the contract and, specifically, required the Elk Hills plant to begin operations of a simple-cycle function while completing its combined cycle facility. SER denies both of these contentions and insists that it may supply the power as it chooses, although it has the option of supplying the DWR from one or more of the plants. Trial has been scheduled for May 2003. Additional information regarding the contract between SER and the DWR is included under "Other Commitments and Contingencies" and "FERC Actions" above.

SER is a defendant in an action brought by the CPUC and the California Electricity Oversight Board at the FERC alleging that, because of the dysfunctional energy market in California, the long-term power contracts entered into by the DWR should be revised or set aside as being unjust and unreasonable. Additional information regarding this complaint and the contract between SER and the DWR is included under "Other Commitments and Contingencies" and "FERC Actions" above.

SET is a defendant in the action at the FERC concerning rates charged certain utilities by sellers of electricity. Management believes it has provided fully for any adverse outcomes of this action.

At December 31, 2002, SET remains due approximately $100 million from energy sales made in 2000 and 2001 through the California Independent System Operator 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.

Management believes that these matters will not have a material adverse effect on the company's financial condition or results of operations.

Electric Distribution System Conversion

Under a CPUC-mandated program and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2002, the aggregate unexpended amount of this commitment was $98 million. Capital expenditures for underground conversions were $33 million in 2002, $12 million in 2001 and $26 million in 2000.

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 discussed in Note 13, SDG&E accumulated certain costs of electricity purchases in a balancing account (the AB 265 undercollection). SDG&E may experience an increase in customer credit risk as it passes on these costs to customers, as well as charges on behalf of the state of California to repay the state bonds issued in connection with its past purchases of power for IOU customers. However, mitigating this increase in customer credit risk are the decline in the cost of the electric commodity and return to stability thereof, and the October 2002 CPUC decision which allows SDG&E to enter into new contracts to procure electric energy and to establish a cost recovery mechanism. The decision establishes a semiannual cost review and rate recovery mechanism with a trigger for more frequent rate changes if balances exceed five percent of annual, non-DWR generation revenues, to provide for timely recovery of any undercollections.

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

NOTE 16. SEGMENT INFORMATION

The company is a holding company, whose subsidiaries are primarily engaged in the energy business. It has four separately managed reportable segments comprised of SoCalGas, SDG&E, SET and SER. (During the third quarter of 2002, SER first met the requirements for disclosure as a reportable segment.) The California Utilities operate in essentially separate service territories under separate regulatory frameworks and rate structures set by the CPUC. SDG&E provides electric service to San Diego and southern Orange counties and natural gas service to San Diego county. SoCalGas is a natural gas distribution utility, serving customers throughout most of southern California and part of central California. 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 develops, owns and operates power plants and natural gas storage, production and transportation facilities within the western United States and Baja California, 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, 2002	2001	2000
OPERATING REVENUES			
Southern California Gas	**$2,858**	$3,716	$2,854
San Diego Gas & Electric	**1,696**	2,362	2,671
Sempra Energy Trading	**821**	1,047	822
Sempra Energy Resources	**349**	178	11
All other	**333**	458	467
Intersegment revenues	**(37)**	(31)	(65)
Total	**$6,020**	$7,730	$6,760
INTEREST INCOME			
Southern California Gas	**$ 5**	$ 22	$ 27
San Diego Gas & Electric	**10**	21	51
Sempra Energy Trading	**11**	11	8
Sempra Energy Resources	**4**	6	—
All other	**84**	73	88
Intercompany elimination	**(72)**	(50)	(106)
Total interest income	**42**	83	68
Equity in income (losses) of unconsolidated affiliates	**(55)**	12	62
Sundry income (loss)	**70**	(9)	(3)
Total other income	**$ 57**	$ 86	$ 127
DEPRECIATION AND AMORTIZATION			
Southern California Gas	**$ 276**	$ 268	$ 263
San Diego Gas & Electric	**230**	207	210
Sempra Energy Trading	**21**	27	32
Sempra Energy Resources	**2**	1	2
All other	**67**	76	56
Total	**$ 596**	$ 579	$ 563
INTEREST EXPENSE			
Southern California Gas	**$ 44**	$ 68	$ 74
San Diego Gas & Electric	**77**	92	118
Sempra Energy Trading	**43**	14	18
Sempra Energy Resources	**6**	7	3
All other	**196**	192	179
Intercompany elimination	**(72)**	(50)	(106)
Total	**$ 294**	$ 323	$ 286
INCOME TAX EXPENSE (BENEFIT)			
Southern California Gas	**$ 178**	$ 169	$ 183
San Diego Gas & Electric	**91**	141	144
Sempra Energy Trading	**60**	87	63
Sempra Energy Resources	**36**	(18)	15
All other	**(219)**	(166)	(135)
Total	**$ 146**	$ 213	$ 270
NET INCOME (LOSS)			
Southern California Gas	**$ 212**	$ 207	$ 206
San Diego Gas & Electric	**203**	177	145
Sempra Energy Trading	**126**	196	155
Sempra Energy Resources	**60**	(27)	29
All other	**(10)**	(35)	(106)
Total	**$ 591**	$ 518	$ 429

(Dollars in millions)	At December 31 or years ended December 31, 2002	2001	2000
ASSETS			
Southern California Gas	**$ 4,079**	$ 3,733	$ 4,128
San Diego Gas & Electric	**5,123**	5,399	4,734
Sempra Energy Trading	**5,614**	2,997	4,627
Sempra Energy Resources	**1,347**	577	276
All other	**2,580**	3,094	2,421
Intersegment receivable	**(986)**	(720)	(646)
Total	**$17,757**	$15,080	$15,540
CAPITAL EXPENDITURES			
Southern California Gas	**$ 331**	$ 294	$ 198
San Diego Gas & Electric	**400**	307	324
Sempra Energy Trading	**21**	45	22
Sempra Energy Resources	**356**	225	59
All other	**106**	197	156
Total	**$ 1,214**	$ 1,068	$ 759
GEOGRAPHIC INFORMATION			
Long-lived assets			
United States	**$ 7,062**	$ 6,515	$ 6,071
Latin America	**1,062**	836	911
Europe	**18**	10	9
Canada	**3**	24	23
Total	**$ 8,145**	$ 7,385	$ 7,014
Operating revenues			
United States	**$ 5,475**	$ 7,169	$ 6,423
Latin America	**168**	280	154
Europe	**328**	250	158
Canada	**28**	15	14
Asia	**21**	16	11
Total	**$ 6,020**	$ 7,730	$ 6,760

NOTE 17. QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarters ended (Dollars in millions, except per share amounts)	March 31	June 30	September 30	December 31
2002				
Operating revenues	**$1,460**	**$1,488**	**$1,384**	**$1,688**
Operating expenses	**1,209**	**1,260**	**1,074**	**1,490**
Operating income	**$ 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**
2001				
Operating revenues	$3,119	$1,895	$1,417	$1,299
Operating expenses	2,747	1,623	1,198	1,165
Operating income	$ 372	$ 272	$ 219	$ 134
Net income	$ 178	$ 137	$ 96	$ 107
Average common shares outstanding (diluted)	203.0	206.0	206.6	206.0
Net income per common share (diluted)	$ 0.88	$ 0.66	$ 0.46	$ 0.52

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
2002				
Market price				
High	**$25.92**	**$26.25**	**$24.11**	**$24.62**
Low	**22.15**	**21.52**	**15.50**	**16.70**
2001				
Market price				
High	$23.94	$28.61	$28.00	$26.68
Low	17.31	21.98	23.25	22.00

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.

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