SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

(Mark One)
[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2002

OR

Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from ______ to _______

SAN DIEGO GAS & ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

CALIFORNIA	1-3779	95-1184800
(State of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.

8326 CENTURY PARK COURT, SAN DIEGO, CALIFORNIA	92123
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (619)696-2000

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Preference Stock (Cumulative) Without Par Value (except $1.70 and $1.7625 Series)	American
Cumulative Preferred Stock, $20 Par Value (except 4.60% Series)	

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None

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

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

Exhibit Index on page 89. Glossary on page 94.

Aggregate market value of the voting preferred stock held by non-affiliates of the registrant as of January 31, 2003 was $21.7 million.

Registrant's common stock outstanding as of January 31, 2003 was wholly owned by Enova Corporation.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the Information Statement prepared for the May 2003 annual meeting of shareholders are incorporated by reference into Part III.

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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 California Public Utilities Commission (CPUC), the California Legislature, the California Department of Water Resources (DWR), and the Federal Energy Regulatory Commission (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.

PART I

ITEM 1. BUSINESS

Description of Business

A description of San Diego Gas & Electric (SDG&E or the company) is given in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein. SDG&E's common stock is wholly owned by Enova Corporation, which is a wholly owned subsidiary of Sempra Energy, a California-based Fortune 500 holding company. The financial statements herein are the Consolidated Financial Statements of SDG&E and its sole subsidiary, SDG&E Funding LLC. Sempra Energy also indirectly owns the common stock of Southern California Gas Company (SoCalGas). SDG&E and SoCalGas are collectively referred to herein as "the California Utilities."

Company Website

The company's website address is http://www.sdge.com/ and its parent company's website address is http://www.sempra.com/investor.htm. The company makes available free of charge via a hyperlink on its website to its parent company's website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission.

GOVERNMENT REGULATION

Local Regulation

SDG&E has electric franchises with the three counties and the 26 cities in its electric service territory, and natural gas franchises with the one county and the 23 cities in its natural gas service territory. These franchises allow SDG&E to locate facilities for the transmission and distribution of electricity and/or natural gas in the streets and other public places. The franchises do not have fixed terms, except for the electric and natural gas franchises with the cities of Chula Vista (2003), Encinitas (2012), San Diego (2021) and Coronado (2028); and the natural gas franchises with the city of Escondido (2036) and the county of San Diego (2030).

California Utility Regulation

The State of California Legislature, from time to time, passes laws that regulate SDG&E's operations. For example, in 1996 the legislature passed an electric industry deregulation bill, and in subsequent years passed additional bills aimed at addressing problems in the deregulated electric industry. In addition, the legislature enacted a law in 1999 addressing natural gas industry restructuring.

The CPUC, which consists of five commissioners appointed by the Governor of California for staggered six-year terms, regulates SDG&E's rates and conditions of service, sales of securities, rate of return, rates of depreciation, uniform systems of accounts, examination of records, and long-term resource procurement. The CPUC conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition and the environment, to determine its future policies. The CPUC also regulates the relationship of utilities with their holding companies and is currently conducting an investigation into this relationship.

The California Energy Commission (CEC) has discretion over electric demand forecasts for the state and for specific service territories. Based upon these forecasts, the CEC determines the need for additional energy sources and for conservation programs. The CEC sponsors alternative-energy research and development projects, promotes energy conservation programs and maintains a state-wide plan of action in case of energy shortages. In addition, the CEC certifies power-plant sites and related facilities within California.

The CEC conducts a 20-year forecast of supply availability and prices for every market sector consuming natural gas in California. This forecast includes resource evaluation, pipeline capacity needs, natural gas demand and wellhead prices, and costs of transportation and distribution. This analysis is used to support long-term investment decisions.

California Power Authority

The California Consumer Power and Financing Authority is responsible for ensuring reliable electricity at reasonable prices. It does so by diversifying its electricity portfolio to include increased renewable energy, permanent conservation efforts and cleaner-burning projects.

United States Utility Regulation

The FERC regulates the interstate sale and transportation of natural gas, the transmission and wholesale sales of electricity in interstate commerce, transmission access, the uniform systems of accounts, rates of depreciation, and electric rates involving sales for resale. Both the FERC and CPUC are currently investigating prices charged to the California investor-owned utilities (IOUs) by various suppliers of natural gas and electricity.

The Nuclear Regulatory Commission (NRC) oversees the licensing, construction and operation of nuclear facilities. NRC regulations require extensive review of the safety, radiological and environmental aspects of these facilities. Periodically, the NRC requires that newly developed data and techniques be used to re-analyze the design of a nuclear power plant and, as a result, requires plant modifications as a condition of continued operation in some cases.

Licenses and Permits

SDG&E obtains a number of permits, authorizations and licenses in connection with the transmission and distribution of natural gas and electricity. In addition, SDG&E obtains a number of permits, authorizations and licenses in connection with the transmission and distribution of electricity. Both require periodic renewal, which results in continuing regulation by the granting agency.

Other regulatory matters are described in Notes 10 and 11 of the notes to Consolidated Financial Statements herein.

SOURCES OF REVENUE

Information on this topic is provided in Note 1 of the notes to Consolidated Financial Statements herein.

ELECTRIC OPERATIONS

Resource Planning

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

Supply/demand imbalances and a number of factors resulted in abnormally high wholesale electric prices beginning in mid-2000, which caused SDG&E's monthly customer bills to be substantially higher than normal. These conditions and the resultant abnormally high electric-commodity prices continued into 2001 resulting in growth of the undercollection of SDG&E's electricity costs.

In response to these high commodity prices, the California legislature adopted legislation intended to stabilize the California electric utility industry and reduce wholesale electric commodity prices. This resulted in several legislative and regulatory responses, including California Assembly Bill (AB) 265, enacted in September 2000 and in effect through December 31, 2002. AB 265 imposed a ceiling of 6.5 cents/kilowatt hour (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. Further actions included the DWR's purchasing through December 31, 2002 the net short position of SDG&E (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 addition, implementation of some of the provisions of the Memorandum of Understanding (MOU) entered into by representatives of California Governor Davis, the DWR, Sempra Energy and SDG&E resulted in the cessation of growth in the AB 265 undercollection.

Additional information concerning direct access, the MOU and electric-industry restructuring in general is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 10, 11 and 12 of the notes to Consolidated Financial Statements herein.

Electric Resources

In connection with California's electric-industry restructuring, beginning March 31, 1998, the California IOUs were obligated to bid their power supply, including owned generation and purchased-power contracts, into the PX. The IOUs also were obligated to purchase from the PX the power that they sell to their customers. In 1999, SDG&E completed divestiture of its owned generation other than nuclear. An Independent System Operator (ISO) schedules power transactions and access to the transmission system. As discussed in Note 10 of the notes to Consolidated Financial Statements, due to the conditions in the California electric utility industry, the PX suspended its trading operations on January 31, 2001.

As discussed above, the California Legislature passed laws (e.g., Assembly Bill X1 in February 2001), authorizing the DWR to enter into long-term contracts to purchase the portion of power used by SDG&E

customers that is not provided by SDG&E's existing supply through December 31, 2002. SDG&E's residual net short requirements have been met by the DWR since February 7, 2001.

In August 2002, SDG&E was granted authority by the CPUC to once again procure electric power to meet the load requirements of its customers, effective January 1, 2003. The California Legislature also passed several laws (e.g., AB 57, Senate Bill (SB) 1078 and SB 1038) which required that (a) purchases made by SDG&E beginning January 1, 2003 not be subject to hindsight regulatory review, except for contract administration functions and (b) SDG&E procure at least one percent of its annual retail energy supply from renewable producers. Each IOU is directed to procure from renewable sources at least one percent of its 2003 total energy sales and add at least one percent of energy sales each year thereafter, such that a 20-percent renewable resources portfolio is achieved by the year 2017.

On September 20, 2002, SDG&E issued a Request for Offer seeking to purchase a variety of energy products from both renewable and non-renewable entities. SDG&E did not enter into any contracts with non-renewable entities but did enter into contracts with 11 renewable suppliers (for 15 projects) for 237 megawatts (mW) of non-firm power starting in 2003. On December 5, 2002, the CPUC issued its resolution approving SDG&E's renewable contract purchases and on December 19, 2003, the CPUC approved SDG&E's 2003 procurement plan. SDG&E has contracted to procure approximately four percent of its 2003 total energy sales from renewable sources and, pursuant to the December 2002 CPUC resolution, may credit toward future years' compliance any excess over its one-percent requirement.

The CPUC also allocated to SDG&E seven of the contracts signed by the DWR during the energy crisis in 2001. The contracts represent 2,754 mW of capacity available to SDG&E in a combination of must-take and dispatchable resources. SDG&E will be responsible for scheduling and dispatching these contracts (where applicable) as well as some contract administration duties.

Based on generating plants in service and purchased-power contracts currently in place, as of January 31, 2003, the mW of electric power available to SDG&E are as follows:

Source	mW
San Onofre Nuclear Generating Station (SONGS)	430*
Long-term contracts with other utilities	84
DWR allocated contracts	2,754
Contracts with others	592
Total	3,860

* Net of internal usage

SONGS: SDG&E owns 20 percent of the three nuclear units at SONGS (located south of San Clemente, California). The cities of Riverside and Anaheim own a total of 5 percent of Units 2 and 3. Southern California Edison (Edison) owns the remaining interests and operates the units.

Unit 1 was removed from service in November 1992 when the CPUC issued a decision to permanently shut down the unit. At that time SDG&E began the recovery of its remaining capital investment, with full recovery completed in April 1996. The unit's spent nuclear fuel has been removed from the reactor and is stored on-site. In March 1993, the NRC issued a Possession-Only License for Unit 1, and the unit was placed in a long-term storage condition in May 1994. In June 1999, the CPUC granted authority to begin decommissioning Unit 1 and this work is now in progress.

Units 2 and 3 began commercial operation in August 1983 and April 1984, respectively. SDG&E's share of the capacity is 214 mW of Unit 2 and 216 mW of Unit 3.

During 2002, SDG&E spent $8 million on capital additions and modifications of Units 2 and 3, and expects to spend $10 million in 2003.

SDG&E deposits funds in external trusts to provide for the decommissioning of all three units.

Additional information concerning the SONGS units, nuclear decommissioning and industry restructuring is provided below and in "Environmental Matters" herein, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 4, 10 and 12 of the notes to Consolidated Financial Statements herein.

Purchased Power: The following table lists contracts with SDG&E's various suppliers:

Supplier	Expiration Date	Megawatt Commitment	Source
Long-Term Contracts with Other Utilities:			
Portland General Electric (PGE)	December 2013	84	Coal
Total		84	
Other Contracts:			
DWR Allocated Contracts			
Williams Energy Marketing & Trading	December 2010	1,875	Gas
Sunrise Power Co. LLC	June 2012	560	Gas
Other DWR contracts	Various terminations from 2003 to 2013	319	Gas and wind
		2,754	
Qualifying Facilities (QFs) --			
Applied Energy Inc.	November 2019	107	Cogeneration
Yuma Cogeneration	May 2024	57	Cogeneration
Goal Line Limited Partnership	February 2025	50	Cogeneration
Other QFs (73)	Various terminations	16	Cogeneration
		230	
Others --			
Renewable (15)	5-15 year terms starting 2003	237	Biomass, bio-gas and wind
Various (3)	December 2003	125	System supply
Total		592	

Under the contract with PGE, SDG&E pays a capacity charge plus a charge based on the amount of energy received. Charges under this contract are based on PGE's costs, including lease payments, fuel expenses, operating and maintenance expenses, transmission expenses, administrative and general expenses, and state and local taxes. Costs under the contracts with QFs are based on SDG&E's avoided cost. Charges under the remaining contracts, which include renewal contracts signed in the fourth quarter of 2002, bilateral contracts executed in 2000 and

2001, and the DWR contracts allocated to SDG&E by the CPUC, are for firm and as-available energy and are based on the amount of energy received. The prices under these contracts are at the market value at the time the contracts were negotiated.

Additional information concerning SDG&E's purchased-power contracts is provided below, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 12 of the notes to Consolidated Financial Statements herein.

Power Pools

SDG&E is a participant in the Western Systems Power Pool, which includes an electric-power and transmission-rate agreement with utilities and power agencies located throughout the United States and Canada. More than 250 investor-owned and municipal utilities, state and federal power agencies, energy brokers, and power marketers share power and information in order to increase efficiency and competition in the bulk power market. Participants are able to make power transactions on standardized terms that have been pre-approved by FERC.

Transmission Arrangements

Pacific Intertie (Intertie): The Intertie, consisting of AC and DC transmission lines, connects the Northwest with SDG&E, Pacific Gas & Electric (PG&E), Edison and others under an agreement that expires in July 2007. SDG&E's share of the Intertie is 266 mW.

Southwest Powerlink: SDG&E's 500-kilovolt Southwest Powerlink transmission line, which is shared with Arizona Public Service Company and Imperial Irrigation District, extends from Palo Verde, Arizona to San Diego. SDG&E's share of the line is 970 mW, although it can be less, depending on specific system conditions.

Mexico Interconnection: Mexico's Baja California Norte system is connected to SDG&E's system via two 230-kilovolt interconnections with firm capability of 408 mW in the north to south direction and 800 mW in the south to north direction.

Due to electric-industry restructuring (see "Transmission Access" below), the operating rights of SDG&E on these lines have been transferred to the ISO.

Transmission Access

The FERC has established rules to implement the transmission-access provisions of the National Energy Policy Act of 1992. These rules specify FERC-required procedures for others' requests for transmission service. In October 1997, the FERC approved the California IOUs' transfer of control of their transmission facilities to the ISO. On March 31, 1998, operation and control of the transmission lines was transferred to the ISO. Additional information regarding the ISO and transmission access is provided below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

Fuel and Purchased-Power Costs

The following table shows the percentage of each electricity source used by SDG&E and compares the kilowatt hour cost of nuclear fuel with the total cost of purchased power:

	Percent of kWh			Cents per kWh		
	2002	2001	2000	2002	2001	2000
Nuclear fuel	23.0	30.1	14.9	0.4	0.5	0.5
Purchased power and ISO/PX	77.0	69.9	85.1	7.4	9.4	9.7
Total	100.0%	100.0%	100.0%			

The cost of purchased power includes capacity costs as well as the costs of fuel. The cost of nuclear fuel does not include SDG&E's capacity costs.

Nuclear Fuel Supply

The nuclear-fuel cycle includes services performed by others under various contracts through 2008, including mining and milling of uranium concentrate, conversion of uranium concentrate to uranium hexafluoride, enrichment services, and fabrication of fuel assemblies.

Spent fuel from SONGS is being stored on site, where storage capacity will be adequate at least through 2005. Modifications in fuel storage technology can be implemented to provide on-site storage capacity for operation through 2022, the expiration date of the NRC operating license. Pursuant to the Nuclear Waste Policy Act of 1982, SDG&E entered into a contract with the U.S. Department of Energy (DOE) for spent-fuel disposal. Under the agreement, the DOE is responsible for the ultimate disposal of spent fuel. SDG&E pays a disposal fee of $1.00 per megawatt-hour of net nuclear generation, or approximately $3 million per year. The DOE projects it will not begin accepting spent fuel until 2010 at the earliest.

To the extent not currently provided by contract, the availability and the cost of the various components of the nuclear-fuel cycle for SDG&E's nuclear facilities cannot be estimated at this time.

Additional information concerning nuclear-fuel costs is provided in Note 12 of the notes to Consolidated Financial Statements herein.

NATURAL GAS OPERATIONS

SDG&E purchases and distributes natural gas to 789,000 end-use customers throughout the western portion of the County of San Diego. SDG&E also transports natural gas to approximately 300 customers who procure the natural gas from other sources.

Supplies of Natural Gas

SDG&E buys natural gas under several short-term and long-term contracts. Short-term purchases are from various Southwest United States and Canadian suppliers and are primarily based on monthly spot-market prices. SDG&E transports natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SDG&E has long-term natural gas transportation contracts with various interstate pipelines which expire on various dates between 2003 and 2023. SDG&E has a long-term purchase agreement with a Canadian supplier that expires in August 2003, and in which the delivered cost is tied to the California border spot-market price. SDG&E purchases natural gas on a spot basis to fill its additional long-term pipeline capacity. SDG&E intends to continue using the long-term pipeline capacity in other ways as well, including the transport of other natural gas for its own use and the release of a portion of this capacity to third parties.

Most of the natural gas purchased and delivered by the company is produced outside of California. These supplies are delivered to the pipeline owned by SoCalGas at the California border by interstate pipeline companies, primarily El Paso Natural Gas Company and Transwestern Natural Gas Company. These interstate companies provide transportation services for supplies purchased from other sources by the company or its transportation customers. The rates that interstate pipeline companies may charge for natural gas and transportation services are regulated by the FERC. All of SDG&E's natural gas is delivered through SoCalGas pipelines under a short-term transportation agreement. In addition, under a separate agreement expiring in March 2003, SoCalGas provides SDG&E 4.5 billion cubic feet of storage capacity. An agreement is expected to be completed with SoCalGas that will extend storage services through March 2004.

The following table shows the sources of natural gas deliveries from 1998 through 2002.

	Years Ended December 31				
	2002	2001	2000	1999	1998
Gas purchases (billions of cubic feet)	54	53	58	75	118
Customer-owned and exchange receipts	90	104	85	47	19
Storage withdrawal (injection) — net	2	(2)	1	4	(3)
Company use and unaccounted for	(6)	—	(5)	—	(2)
Net deliveries	140	155	139	126	132
Cost of gas purchased* (millions of dollars)	$ 182	$ 482	$ 277	$ 205	$ 327
Average Commodity Cost of Purchases (dollars per thousand cubic					

~~feet)~~
~~$3.37~~
~~$9.09~~
~~$4.77~~
~~$2.73~~
~~$2.77~~
~~=======~~
~~=======~~
~~=======~~
~~=======~~
~~======= *~~
~~Includes~~
~~interstate~~
~~pipeline~~
~~demand~~
~~charges~~

Market-sensitive natural gas supplies (supplies purchased on the spot market as well as under longer-term contracts, ranging from one month to two years, based on spot prices) accounted for nearly all of total natural gas volumes purchased by the company. The annual average price of natural gas at the California/Arizona border was $3.14/million British thermal units (mmbtu) in 2002, compared with $7.27/mmbtu in 2001 and $6.25/mmbtu in 2000. Supply/demand imbalances and a number of other factors associated with California's energy crisis from late 2000 through early 2001 resulted in higher natural gas prices during that period. Prices for natural gas decreased in the later part of 2001 and increased toward the end of 2002. As of December 31, 2002, the average spot cash price at the California/Arizona border was $4.47/mmbtu. The cost of gas purchased may vary and can exceed the annual average price.

During 2002, the company delivered 140 billion cubic feet (bcf) of natural gas. Approximately 64 percent of these deliveries were customer-owned natural gas for which the company provided transportation services. The remaining natural gas deliveries were purchased by the company and resold to customers.

Customers

For regulatory purposes, customers are separated into core and noncore customers. Core customers are primarily residential and small commercial and industrial customers, without alternative fuel capability. Noncore customers consist primarily of utility electric generating (UEG) plants, wholesale purchasers, and large commercial and industrial customers. As of December 31, 2002, SDG&E had 789,000 core customers (760,000 residential and 29,000 small commercial and industrial) and 100 noncore customers.

Most core customers purchase natural gas directly from the company. Core customers are permitted to aggregate their natural gas requirement and, for up to 10 percent of the company's core market, to purchase natural gas directly from brokers or producers. The CPUC tentatively authorized the removal of the 10 percent limit, but this has yet to be implemented. SDG&E continues to be obligated to purchase reliable supplies of natural gas to serve the requirements of its core customers. In early 2002, the California Utilities filed an application with the CPUC to combine their core procurement portfolios. On August 22, 2002, the CPUC issued an interim decision denying the request, pending completion of the CPUC's ongoing investigation of market power issues.

The CPUC ordered that utility procurement services offered to noncore customers be phased out sometime in 2003. Noncore customers would have the option to either become core customers, and continue to receive utility procurement services, or remain noncore customers and purchase their natural gas from other sources, such as brokers or producers. Noncore customers would also have to make arrangements to deliver their purchases to the company's receipt points for delivery through the company's transmission and distribution system. The proposed implementation of the order has encountered significant opposition and the CPUC is reconsidering its decision.

In 2002, 89 percent of the CPUC-authorized natural gas margin was allocated to the core customers, with 11 percent allocated to the noncore customers.

Although revenues from transportation throughput is less than for natural gas sales, the company generally earns the same margin whether the company buys the natural gas and sells it to the customer or transports natural gas already owned by the customer.

Demand for Natural Gas

Natural gas is a principal energy source for residential, commercial, industrial and UEG plant customers. Natural gas competes with electricity for residential and commercial cooking, water heating, space heating and clothes drying, and with other fuels for large industrial, commercial and UEG uses. Growth in the natural gas markets is largely dependent upon the health and expansion of the southern California economy. The company added 14,000 and 12,000 new customer meters in 2002 and 2001, respectively, representing growth rates of 1.8 percent and 1.6 percent, respectively. The company expects that its growth rate for 2003 will approximate that of 2002.

During 2002, 90 percent of residential energy customers used natural gas for water heating, 73 percent for space heating, 54 percent for cooking and 38 percent for clothes drying.

Demand for natural gas by noncore customers is very sensitive to the price of competing fuels. Although the number of noncore customers in 2002 was only 100 they accounted for approximately 6 percent of the authorized natural gas revenues and 63 percent of total natural gas volumes. External factors such as weather, the price of electricity, electric deregulation, the use of hydroelectric power, competing pipelines and general economic conditions can result in significant shifts in demand and market price. The demand for natural gas by large UEG customers is also greatly affected by the price and availability of electric power generated in other areas.

Effective March 31, 1998, electric industry restructuring gave California electric utilities the option of purchasing energy for their customers from out-of-state producers. As a result, natural gas demand for electric generation within southern California competes with electric power generated throughout the western United States. Although electric industry restructuring has no direct impact on the company's natural gas operations, future volumes of natural gas transported for electric generating plant customers may be significantly affected to the extent that regulatory changes divert electricity generation from the company's service area.

Other

The Pipeline Safety Improvement Act of 2002, which became public law on December 17, 2002, requires that baseline inspections be completed over a ten-year period, with 50 percent of the inspections complete at the end of five years. Related to these inspections and potential retrofits, the company estimates that it will have $0.5 million in operating and maintenance expense each year.

Additional information concerning customer demand and other aspects of natural gas operations is provided under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 11 and 12 of the notes to Consolidated Financial Statements herein.

RATES AND REGULATION

Electric Industry Restructuring

A flawed electric-industry restructuring plan, electricity supply/demand imbalances, and legislative and regulatory responses have significantly impacted the company's operations. Additional information on electric-industry restructuring is provided above under "Electric Operations," in "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in Note 10 of the notes to Consolidated Financial Statements herein.

Natural Gas Industry Restructuring

The natural gas industry in California experienced an initial phase of restructuring during the 1980s. In December 2001 the CPUC issued a decision adopting provisions affecting the structure of the natural gas industry in California, some of which could introduce additional volatility into the earnings of SDG&E and other market participants. 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. Additional information on natural gas industry restructuring is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 11 of the notes to Consolidated Financial Statements herein.

Balancing Accounts

In general, earnings fluctuations from changes in the costs of natural gas and consumption levels for the majority of natural gas are eliminated through balancing accounts authorized by the CPUC. As a result of California's electric restructuring law, overcollections recorded in the electric balancing accounts were applied to transition cost recovery, and fluctuations in certain costs and consumption levels can now affect earnings from electric operations. In addition, fluctuations in certain costs and consumption levels affect earnings from the California Utilities' natural gas operations. Additional information on balancing accounts is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 1 of the notes to Consolidated Financial Statements herein.

Biennial Cost Allocation Proceeding (BCAP)

Rates to recover the changes in the cost of natural gas transportation services are determined in the BCAP. Additional information on the BCAP is provided in Note 11 of the notes to Consolidated Financial Statements herein.

Cost of Capital

The authorized cost of capital is determined by an automatic adjustment mechanism based on changes in certain capital market indices. Additional information on SDG&E's cost of capital is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 11 of the notes to Consolidated Financial Statements herein.

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. PBR has resulted in modification to the general rate case and certain other regulatory proceedings for SDG&E. 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. Rewards resulting from PBR are not included in the company's earnings before they are approved by the CPUC. Additional information on SDG&E's PBR mechanism is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 11 of the notes to Consolidated Financial Statements herein.

ENVIRONMENTAL MATTERS

Discussions about environmental issues affecting the company are included in Note 12 of the Consolidated Financial Statements herein. The following additional information should be read in conjunction with those discussions.

Hazardous Substances

In 1994, the CPUC approved the Hazardous Waste Collaborative Memorandum account, allowing California's IOUs to recover their hazardous waste cleanup costs, including those related to Superfund sites or similar sites requiring cleanup. Cleanup costs at sites related to electric generation were specifically excluded from the collaborative by the CPUC. Recovery of 90 percent of hazardous waste cleanup costs and related third-party litigation costs and 70 percent of the related insurance-litigation expenses is permitted. In addition, the company has the opportunity to retain a percentage of any insurance recoveries to offset the 10 percent of costs not recovered in rates.

During the early 1900s, SDG&E and its predecessors manufactured gas from coal or oil. The manufacturing sites often have become contaminated with the hazardous residual by-products of the process. SDG&E identified three former manufactured-gas plant sites, remediation of which was completed at two of the sites in 1998 and 2000. Closure letters have been received for the two sites. At December 31, 2002 estimated remaining remediation liability on the third site is $1.5 million.

SDG&E sold its fossil-fuel generating facilities in 1999. As a part of its due diligence for the sale, SDG&E conducted a thorough environmental assessment of the facilities. Pursuant to the sale agreements for such facilities, SDG&E and the buyers have apportioned responsibility for such environmental conditions generally based on contamination existing at the time of transfer and the cleanup level necessary for the continued use of the sites as industrial sites. While the sites are relatively clean, the assessments identified some instances of significant contamination, principally resulting from hydrocarbon releases, for which SDG&E has a cleanup obligation under the agreement. Estimated costs to perform the necessary remediation are $11 million. These costs were offset against the sales price for the facilities, together with other appropriate costs, and the remaining net proceeds were included in the calculation of customer rates. Remediation of the plants commenced in early 2001. During 2002, cleanup was completed at several minor sites at a cost of $0.4 million. In late 2002, additional assessments were started at the primary sites, where cleanup in expected to commence by the end of 2003 and be completed by 2005.

SDG&E lawfully disposes of wastes at permitted facilities owned and operated by other entities. Operations at these facilities may result in actual or threatened risks to the environment or public health. Under California law, businesses that arrange for legal disposal of wastes at a permitted facility from which wastes are later released, or threaten to be released, can be held financially responsible for corrective actions at the facility.

At December 31, 2002, the company's estimated remaining investigation and remediation liability related to hazardous waste sites, including the manufactured gas sites, was $3 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation costs associated with SDG&E's former fossil-fuel power plants. The company believes that any costs not ultimately recovered through rates, insurance or other means will not have a material adverse effect on the company's consolidated results of operations or financial position.

Estimated liabilities for environmental remediation are recorded when amounts are probable and estimable. Amounts authorized to be recovered in rates under the Hazardous Waste Collaborative mechanism are recorded as a regulatory asset.

Electric and Magnetic Fields (EMFs)

Although scientists continue to research the possibility that exposure to EMFs causes adverse health effects, science has not demonstrated a cause-and-effect relationship between exposure to the type of EMFs emitted by power lines and other electrical facilities and adverse health effects. Some laboratory studies suggest that such exposure creates biological effects, but those effects have not been shown to be harmful. The studies that have most concerned the public are epidemiological studies, some of which have reported a weak correlation between the proximity of homes to certain power lines and equipment and childhood leukemia. Other epidemiological studies found no correlation between estimated exposure and any disease. Scientists cannot explain why some studies using estimates of past exposure report correlations between estimated EMF levels and disease, while others do not.

To respond to public concerns, the CPUC has directed California IOUs to adopt a low-cost EMF-reduction policy that requires reasonable design changes to achieve noticeable reduction of EMF levels that are anticipated from new projects. However, consistent with the major scientific reviews of the available research literature, the CPUC has indicated that no health risk has been identified.

Air and Water Quality

California's air quality standards are more restrictive than federal standards. However, as a result of the sale of the company's fossil-fuel generating facilities, the company's primary air-quality issue, compliance with these standards now has less significance to the company's operation.

The transmission and distribution of natural gas require the operation of compressor stations, which are subject to increasingly stringent air-quality standards. Costs to comply with these standards are recovered in rates.

In connection with the issuance of operating permits, SDG&E and the other owners of SONGS reached agreement with the California Coastal Commission to mitigate the environmental damage to the marine environment attributed to the cooling-water discharge from SONGS Units 2 and 3. This mitigation program includes an enhanced fish-protection system, a 150-acre artificial reef and restoration of 150 acres of coastal wetlands. In addition, the owners must deposit $3.6 million with the state for the enhancement of fish hatchery programs and pay for monitoring and oversight of the mitigation projects. SDG&E's share of the cost is estimated to be $34.8 million. These mitigation projects are expected to be completed by 2007. Through December 31, 2003, SONGS mitigation costs are recovered through the Incremental Cost Incentive Pricing mechanism. Costs thereafter are anticipated to be recovered in customer rates.

OTHER MATTERS

Research, Development and Demonstration (RD&D)

For 2002, the CPUC authorized SDG&E to fund $1.2 million and $4.0 million for its natural gas and electric RD&D programs, respectively, which includes $3.9 million to the CEC for its PIER (Public Interest Energy Research) Program. SDG&E co-funded several of these projects with the CEC. SDG&E's annual RD&D costs have averaged $4.4 million over the past three years.

Employees of Registrant

As of December 31, 2002 the company had 4,130 employees, compared to 3,106 at December 31, 2001. The increase is due to transferring certain central functions for SDG&E and its affiliate, SoCalGas, from Sempra Energy to SDG&E effective April 1, 2002.

Labor Relations

Certain employees at SDG&E are represented by the Local 465 International Brotherhood of Electrical Workers. The current contract runs through August 31, 2004.

ITEM 2. PROPERTIES

Electric Properties

SDG&E's generating capacity is described in "Electric Resources" herein. At December 31, 2002, SDG&E's electric transmission and distribution facilities included substations, and overhead and underground lines. The electric facilities are located in San Diego, Imperial and Orange counties and in Arizona, and consist of 1,802 miles of transmission lines and 21,095 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

Natural Gas Properties

At December 31, 2002, SDG&E's natural gas facilities, which are located in San Diego and Riverside counties, consisted of the Moreno and Rainbow compressor stations, 166 miles of high pressure transmission pipelines, 7,617 miles of high and low pressure distribution mains, and 6,079 miles of service lines.

Other Properties

SDG&E occupies an office complex in San Diego pursuant to an operating lease ending in 2007. The lease can be renewed for two five-year periods.

SDG&E owns or leases other offices, operating and maintenance centers, shops, service facilities and equipment necessary in the conduct of its business.

ITEM 3. LEGAL PROCEEDINGS

Except for the matters described in Note 12 of the notes to Consolidated Financial Statements or referred to elsewhere in this Annual Report, neither the company nor its subsidiary are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

All of the issued and outstanding common stock of SDG&E is owned by Enova Corporation, a wholly owned subsidiary of Sempra Energy. The information required by Item 5 concerning dividends declared is included in the "Statements of Consolidated Changes in Shareholders' Equity" set forth in Item 8 of this Annual Report herein.

ITEM 6. SELECTED FINANCIAL DATA

(Dollars in millions) At December 31, or for the years then ended	2002	2001	2000	1999	1998
~~Income Statement Data:~~					
~~Operating revenues~~	~~$ 1,696~~	~~$ 2,362~~	~~$ 2,671~~	~~$ 2,207~~	~~$ 2,249~~
~~Operating income~~	~~$ 262~~	~~$ 221~~	~~$ 235~~	~~$ 281~~	~~$ 286~~
~~Dividends on preferred stock~~	~~$ 6~~	~~$ 6~~	~~$ 6~~	~~$ 6~~	~~$ 6~~
~~Earnings applicable to common shares~~	~~$ 203~~	~~$ 177~~	~~$ 145~~	~~$ 193~~	~~$ 185~~
~~Balance Sheet Data:~~					
~~Total assets~~	~~$ 5,123~~	~~$ 5,399~~	~~$ 4,734~~	~~$ 4,366~~	~~$ 4,257~~
~~Long-term debt~~	~~$ 1,153~~	~~$ 1,229~~	~~$ 1,281~~	~~$ 1,418~~	~~$ 1,548~~
~~Short-term debt (a)~~	~~$ 66~~	~~$ 93~~	~~$ 66~~	~~$ 66~~	~~$ 72~~
~~Preferred stock subject to mandatory redemption~~	~~$ 25~~	~~$ 25~~	~~$ 25~~	~~$ 25~~	~~$ 25~~
~~Shareholders' equity~~	~~$ 1,223~~	~~$ 1,165~~	~~$ 1,138~~	~~$ 1,393~~	~~$ 1,203~~

~~(a) Includes long-term debt due~~

~~within one year.~~

Since San Diego Gas & Electric Company is a wholly owned subsidiary of Enova Corporation, per share data is not provided.

This data should be read in conjunction with the Consolidated Financial Statements and the notes to Consolidated Financial Statements contained herein.

ITEM 7. 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 San Diego Gas & Electric (SDG&E or 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 herein.

The company is an operating public utility engaged in the electric and natural gas businesses, which provides services to 3.1 million customers. It distributes electric energy, purchased from others or generated from its 20 percent interest in a nuclear facility, through 1.3 million electric meters in San Diego County and an adjacent portion of southern Orange County, California. It also purchases and distributes natural gas through 789,000 meters in San Diego County and transports electricity and gas for others. SDG&E's service area encompasses 4,100 square miles, covering 26 cities. SDG&E's only subsidiary is SDG&E Funding LLC, which was formed to facilitate the issuance of SDG&E's rate reduction bonds described in Note 3 of the notes to Consolidated Financial Statements.

Business Combination

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

RESULTS OF OPERATIONS

To understand the operations and financial results of the company, it is important to understand the ratemaking procedures to which the company is subject.

SDG&E is 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 California Department of Water and Resources (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 company believes 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 company 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 service, safety, reliability, 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 10 and 11 of the notes to Consolidated Financial Statements.

The tables summarize the components of electric and natural gas volumes and revenues by customer class.

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	1,893	161	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
	17,753	1,569	17,876	2,035	19,322	1,952

~~Balancing and other~~
~~(295)~~
~~(359) 232~~

~~Total~~
~~17,753~~
~~$1,274~~
~~17,876~~
~~$1,676~~
~~19,322~~
~~$2,184~~

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

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~~
~~33 $ 246 $~~
~~1 33 $ 247~~
~~Commercial~~
~~and~~
~~industrial 17~~
~~98 5 15 22~~
~~113 Electric~~
~~generation~~
~~plants~~
~~85 16 85 16~~
~~50~~
~~$ 344 90 $ 32~~
~~140 376~~
~~Balancing~~
~~accounts and~~
~~other 46~~
~~Total $~~
~~422~~
~~2001:~~
~~Residential~~
~~34 $ 461 $~~
~~34 $ 461~~
~~Commercial~~
~~and~~
~~industrial 18~~
~~233 4 18 22~~
~~251 Electric~~
~~generation~~
~~plants~~
~~99 23 99 23~~
~~52~~
~~$ 694 103 $~~
~~41 155 735~~
~~Balancing~~
~~accounts and~~
~~other (49)~~
~~Total~~
~~$ 686~~

~~2000:~~
~~Residential~~
~~33 $ 279 -- $~~
~~1 33 $ 280~~
~~Commercial~~
~~and~~
~~industrial 21~~
~~139 22 16 43~~
~~155 Electric~~
~~generation~~
~~plants ------~~
~~63 24 63 24 -~~
~~---------- 54~~
~~$ 418 85 $ 41~~
~~139 459~~
~~Balancing~~
~~accounts and~~
~~other 28 -----~~
~~----- Total $~~
~~487 ---------~~

2002 Compared to 2001

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 $324 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 10 of the notes to Consolidated Financial Statements for further discussion of ICIP and the San Onofre Nuclear Generating Station (SONGS).

Natural Gas Revenue and Cost of Gas Distributed. Natural gas revenues decreased to $422 million in 2002 from $686 million in 2001, and the cost of natural gas distributed decreased to $205 million in 2002 from $457 million in 2001. These decreases were primarily due to lower average natural gas commodity prices as well as lower volumes of gas sales in 2002. The reduction in natural gas volumes in the electric generation market is largely attributable to the loss of approximately 100 million cubic feet per day of throughput on the SDG&E system when the North Baja pipeline began service in September 2002 and to the lower level of electric generation demand.

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. See further discussion in Note 1 of the notes to Consolidated Financial Statements.

Other Operating Expenses. Other operating expenses increased to $531 million in 2002 from $491 million in 2001. For the fourth quarter, other operating expenses increased to $164 million in 2002 from $147 million in 2001. These increases were primarily due to higher labor and employee benefits costs and increases in other operating costs, including operating costs that are associated with nuclear generating facilities.

Other Income. Other income and deductions, which primarily consist of interest income and/or expense from short-term investments and regulatory balancing accounts, decreased to $24 million in 2002 from $54 million in 2001. For the fourth quarter, other income decreased to $10 million in 2002 from $38 million in 2001. The decreases were primarily due to the reduced interest income from short-term investments, as well as the $19 million gain on sale of SDG&E's Blythe, California property in 2001 (discussed below in "Cash Flows From Investing Activities").

Interest Expense. Interest expense was $77 million and $92 million in 2002 and 2001, respectively. For the fourth quarter, interest expense decreased to $18 million in 2002 from $22 million in 2001. The decrease in interest expense in 2002 was primarily due to lower interest incurred as the result of lower average debt and lower interest rates in 2002. Interest rates on certain of the company's debt can vary with credit ratings, as described in Notes 2 and 3 of the notes to Consolidated Financial Statements. In addition, see further discussion of rate-reduction bonds in Note 3.

Income Taxes. Income tax expense was $91 million and $141 million for the years ended December 31, 2002 and 2001, respectively. The effective income tax rates were 30.3 percent and 43.5 percent for the same years. The decrease in income tax expense was primarily due to the fact that SDG&E received a $25 million favorable resolution of income-tax issues from prior years in 2002.

Net Income. Net income increased to $209 million in 2002 from $183 million in 2001. The increase was primarily due to the $25 million 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 the sale of SDG&E's Blythe property and lower interest income in 2002. Net income increased to $54 million for the fourth quarter of 2002, compared to $46 million for the corresponding period of 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.

2001 Compared to 2000

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.

Natural Gas Revenue and Cost of Gas Distributed. Natural gas revenues increased to $686 million in 2001 from $487 million in 2000, and the cost of natural gas distributed increased to $457 million in 2001 from $273 million in 2000. These increases were primarily due to higher average prices for natural gas in 2001. For the fourth quarter, natural gas revenues decreased to $105 million in 2001 from $178 million in 2000, and the cost of natural gas distributed decreased to $55 million in 2001 from $119 million in 2000. These decreases were attributable to the lower natural gas costs in the fourth quarter of 2001.

Other Operating Expenses. Other operating expenses increased to $491 million in 2001 from $412 million in 2000. For the fourth quarter, other operating expenses increased to $147 million in 2001 from $135 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.

Other Income. Other income and deductions, which primarily consists of interest income and/or expense from short-term investments and regulatory balancing accounts, was $54 million and $34 million in 2001 and 2000, respectively. For the fourth quarter, other income increased to $38 million in 2001 from $10 million in 2000. The increase from 2000 to 2001 was primarily due to the $19 million gain on sale of SDG&E's Blythe, California property (discussed below in "Cash Flows From Investing Activities") in 2001, partially offset by lower interest income from affiliates due to loan repayments by Sempra Energy in 2000.

Interest Expense. Interest expense was $92 million and $118 million in 2001 and 2000, respectively. The decrease in interest expense in 2001 was primarily due to refunds made to customers in 2000 for the rate-reduction bond liability, and lower interest incurred as the result of the remarketing of variable-rate debt during the first quarter of 2001.

Income Taxes. Income tax expense was $141 million and $144 million for the years ended December 31, 2001 and 2000, respectively. The effective income tax rates were 43.5 percent and 48.8 percent for the same years. The decreases in the tax expense and effective rate in 2001 were due primarily to higher state tax depreciation in 2000 and the 2001 income tax issues.

Net Income. Net income increased to $183 million in 2001 from $151 million in 2000. The increase was primarily due to the gain on sale of SDG&E's Blythe property and lower interest expense, as well as the $30 million after-tax charge for regulatory issues in 2000. These increases were partially offset by lower interest income from affiliates. Net income increased to $46 million for the fourth quarter of 2001, compared to $39 million for the corresponding period in 2000. This increase was primarily due to the sale of the Blythe property.

CAPITAL RESOURCES AND LIQUIDITY

The company's operations are the major source of liquidity. 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 10 of the notes to Consolidated Financial Statements.

Management continues to regularly monitor the company's ability to adequately meet the needs of its operating, financing and investing activities.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $757 million, $557 million and $174 million 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, $215 million at December 31, 2002 and $183 million on January 31, 2003, from a high in mid-2001 of $750 million), the refunds to large customers in 2001 resulting from AB 43X and the increase in accounts payable. The increase was partially offset by the decrease in deferred income taxes and investment tax credits and the decrease in regulatory balancing accounts. See further discussion on the 2001 impact of regulatory balancing accounts activity below.

The increase in cash flows from operating activities in 2001 compared to 2000 was primarily due to lower refunds paid to customers in 2001 and the increase in overcollected regulatory balancing accounts, partially offset by a decrease in accounts payable. The decrease in accounts payable was due to decreases in the average prices for natural gas and the DWR's purchasing of SDG&E's net short position for electricity.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash provided by (used in) investing activities totaled $(611) million, $(310) million and $288 million 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 and advances to Sempra Energy, which are payable on demand.

For 2001, cash flows used in investing activities primarily consisted of capital expenditures of $307 million for the upgrade and expansion of utility plant. The decrease in cash flows from investing activities in 2001 was attributable to loan repayments from Sempra Energy in 2000. In addition, the increase in proceeds from sale of assets was due to the sale of property in Blythe, California, for $42 million.

Capital Expenditures for Utility Plant

Capital expenditures were $400 million in 2002, compared to $307 million and $324 million in 2001 and 2000, respectively. Capital expenditures in 2002 were up from 2001 due to additions and improvements to the company's natural gas and electric distribution systems. Capital expenditures for 2001 were only slightly down from 2000.

Future Construction Expenditures

Significant capital expenditures in 2003 are expected to include $400 million for additions to the company's natural gas and electric distribution systems. 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 $2 billion.

Construction 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.

The company's level of construction expenditures 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 used in financing activities totaled $309 million, $181 million and $543 million for 2002, 2001 and 2000, respectively.

Net cash used for financing activities increased in 2002 from 2001 due primarily to higher dividend payments and the absence of debt issuances in 2002.

Net cash used in financing activities decreased in 2001 primarily due to higher dividends paid to Sempra Energy in 2000 and the increase in long-term debt issuances in 2001.

Long-Term and Short-Term Debt

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 relating to long-term debt. 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 2002, repayments on long-term debt included repayments of $66 million of rate-reduction bonds and $28 million of 7.625% first-mortgage bonds. In addition, in July 2002, SDG&E called $10 million of its 8.5% first-mortgage bonds.

In 2001, repayments on long-term debt included $66 million of rate-reduction bonds and $25 million of unsecured variable-rate bonds. During 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 2000, repayments on long-term debt included $66 million of rate-reduction bonds. $10 million of first-mortgage bonds were also repaid in 2000.

Dividends

Dividends paid to Sempra Energy amounted to $200 million in 2002, compared to $150 million in 2001 and $400 million 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 SDG&E's capital structure limits the amounts that are available for loans and dividends to Sempra Energy from SDG&E. At December 31, 2002, the company could have provided a total of $250 million to Sempra Energy. At December 31, 2002, SDG&E had loans to Sempra Energy of $250 million.

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 $2.1 billion. The debt-to-capitalization ratio was 42 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 $159 million of cash and $300 million of revolving lines of credit. Management believes these amounts and cash flows from operations and new debt issuances will be adequate to finance capital expenditures and other commitments.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2002 (dollars in millions). Liabilities reflecting fixed price contracts and other derivatives are excluded as they are primarily offset against regulatory assets and would be recovered from customers through the ratemaking process. Additional information concerning commitments is provided above and in Notes 4, 9 and 12 of the notes to Consolidated Financial Statements.

	By Period				
Description	2003	2004 and 2005	2006 and 2007	Thereafter	Total
Long-term debt	$ 66	$ 132	$ 132	$ 889	$1,219
Operating leases	16	26	16	17	75
Purchased-power contracts	257	455	437	2,285	3,434
Natural gas contracts	31	27	23	153	234
Preferred stock subject to mandatory redemption	--	3	3	19	25
Construction commitments	3	--	--	95	98
SONGS decommissioning	20	22	9	258	309
Environmental commitments	5	10	--	--	15
Totals	$ 398	$ 675	$ 620	$3,716	$5,409

Credit Ratings

As of January 31, 2003, credit ratings for SDG&E were as follows:

	S&P	Moody's	Fitch
Secured Debt	A+	A1	AA
Unsecured Debt	A	A2	AA-
Preferred Stock	A-	Baa1	A+
Commercial Paper	A-1	P-1	F1+

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

FACTORS INFLUENCING FUTURE PERFORMANCE

The factors influencing future performance are summarized below.

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 10 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 company and other market participants: a system for shippers to hold firm, tradable rights to capacity on SoCalGas' major gas transmission lines; 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 SDG&E and SoCalGas. 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 Rate of Return

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. The company 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 SDG&E 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. 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. SDG&E's profitability is dependent upon its ability to control costs within base rates. SDG&E's PBR mechanism is in effect through December 31, 2003, at which time the mechanism will be updated. That update will include, among other things, a reexamination of the company's reasonable costs of operation to be allowed in rates. The October 10, 2001 decision also denied the company's 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 company's 2003 net income by $11 million.

Utility Integration

On September 20, 2001, the CPUC approved Sempra Energy's request to integrate the management teams of SDG&E and SoCalGas. 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 SDG&E and SoCalGas to combine their natural gas procurement activities at this time, pending completion of the CPUC's ongoing investigation of market power issues.

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 rates.

The company's policy is to use derivative physical and financial instruments to reduce its exposure to fluctuations in interest rates, and commodity prices. 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. 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 on a delayed basis detailing positions creating market and credit risk for the company, consistent with affiliate rules. The ERMG independently measures and reports the market and credit risk associated with these positions. In addition, the company's risk-management committee monitors 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 the company. Historical volatilities and correlations between instruments and positions are used in the calculation. As of December 31, 2002, the total VaR of the company's natural gas positions was not material.
The company uses energy derivatives to manage natural gas price risk associated with servicing their load requirements. In addition, the company makes 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 is subject to certain limitations imposed by company policy and regulatory requirements. See the continuing discussion below and Note 8 of the notes to Consolidated Financial Statements for further information regarding the use of energy derivatives by the company. Additional information is provided in Note 8 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 natural gas and electricity. 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 is exposed, in varying degrees, to price risk primarily in the 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

The company's market risk exposure is limited due to CPUC authorized rate recovery of electric procurement and natural gas purchase, sale and storage activity. However, the company may, at times, be exposed to market risk as a result of activities under SDG&E's natural gas PBR and electric procurement, which is discussed in Notes 10 and 11 of the notes to Consolidated Financial Statements. The company manages its risk within the parameters of the company's market-risk management and trading framework. As of December 31, 2002, the company's exposure to market risk 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 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 company had $1,062 million of fixed-rate debt and $157 million 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, SDG&E's fixed-rate debt had a one-year VaR of $200 million and SDG&E's variable-rate debt had a one-year VaR of $0.1 million.

At December 31, 2002, the company did not have any outstanding interest-rate swap transactions. See Notes 3 and 8 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 company's credit department. Using rigorous models, the company's credit department continuously calculates current and potential credit risk to counterparties to ensure the risk stays within approved limits and reports this information to the ERMG. 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.

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.

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.

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 collectibility of regulatory and other assets.

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 Financial Accounting Standards Board (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 the 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.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A is set forth under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Market Risk."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of San Diego Gas & Electric Company:

We have audited the accompanying consolidated balance sheets of San Diego Gas & Electric Company and subsidiary (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 San Diego Gas & Electric Company and subsidiary 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.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 14, 2003

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED INCOME
Dollars in millions

	Years ended December 31, 2002	2001	2000
OPERATING REVENUES			
Electric	$1,274	$1,676	$2,184
Natural gas	422	686	487
Total operating revenues	1,696	2,362	2,671
OPERATING EXPENSES			
Electric fuel and net purchased power	297	782	1,326
Cost of natural gas distributed	205	457	273
Other operating expenses	531	491	412
Depreciation and decommissioning	230	207	210
Income taxes	93	122	134
Franchise fees and other taxes	78	82	81
Total operating expenses	1,434	2,141	2,436
Operating Income	262	221	235
Other Income and (Deductions)			
Interest income	10	21	51
Regulatory interest	(7)	5	(8)
Allowance for equity funds used during construction	15	5	6
Taxes on non-operating income	2	(19)	(10)
Other - net	4	42	(5)
Total	24	54	34
Interest Charges			
Long-term debt	75	84	81
Other	8	12	39
Allowance for borrowed funds used during construction	(6)	(4)	(2)

~~Total 77 92 118~~

~~Net Income 209 183 151~~

~~Preferred Dividend Requirements 6 6 6~~

~~Earnings Applicable to Common Shares $ 203 $ 177 $ 145~~

~~====== ====== ======~~

~~See notes to Consolidated Financial Statements.~~

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
Dollars in millions
December 31, --

--- 2002 2001 -
----- ------

~~ASSETS Utility plant -- at original cost $5,408 $5,009 Accumulated depreciation and decommissioning (2,775) (2,642)~~
~~Utility plant -- net 2,633 2,367~~
~~Nuclear decommissioning trusts 494 526~~
~~Current assets: Cash and cash equivalents 159 322 Accounts receivable -- trade 163 160 Accounts receivable -- other 18 27 Due from unconsolidated affiliates 292 28 Income taxes receivable -- 73 Regulatory assets arising from fixed-price contracts and other derivatives 59 83 Other regulatory assets 75 75 Inventories 46 70 Other 11 4~~
~~Total current assets 823 842~~
~~Other assets: Deferred taxes recoverable in rates 190 162 Regulatory assets arising from fixed-price contracts and other derivatives 579 634 Other regulatory assets 342 842 Sundry 62 26~~
~~Total other assets 1,173 1,664~~
~~Total assets $5,123 $5,399 ====== ====== See notes to Consolidated Financial Statements.~~

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
Dollars in millions
December 31, --

-- 2002 2001 --
---- ------

~~CAPITALIZATION AND LIABILITIES Capitalization: Common stock (255,000,000 shares authorized; 116,583,358 shares outstanding) $ 943 $ 857 Retained earnings 235 232 Accumulated other comprehensive income (loss) (34) (3) -------- ------- Total common equity 1,144 1,086 Preferred stock not subject to mandatory redemption 79 79 --------------- -- Total shareholders' equity 1,223 1,165 Preferred stock subject to mandatory redemption 25 25 Long-term debt 1,153 1,229 ---------- ----- Total capitalization 2,401 2,419 --- -----------~~

~~Current liabilities: Accounts payable 159 139 Interest payable 12 12 Due to unconsolidated affiliates 3 -- Income taxes payable 41 -- Deferred income taxes 53 128 Regulatory balancing accounts - net 394 575 Fixed-price contracts and other derivatives 59 84 Current portion of long-term debt 66 93 Other 170 174 --------------- -- Total current liabilities 957 1,205 ---------- ----- Deferred credits and other~~

~~liabilities: Customer advances for construction 54 42 Deferred income taxes 602 639 Deferred investment tax credits 42 45 Fixed-price contracts and other derivatives 579 634 Due to unconsolidated affiliates 16 5 Deferred credits and other liabilities 472 410 --------------- Total deferred credits and other liabilities 1,765 1,775 --------------- Contingencies and commitments (Note 12) Total liabilities and shareholders' equity $5,123 $5,399 ====== ====== See notes to Consolidated Financial Statements.~~

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CASH FLOWS
Dollars in millions
Years Ended
December 31,
2002 2001 2000
------- -------
------- ~~CASH FLOWS FROM OPERATING ACTIVITIES Net income $ 209 $ 183 $ 151 Adjustments to reconcile net income to net cash provided by operating activities: Depreciation and amortization 230 207 210 Customer refunds paid -- (127) (628) Deferred income taxes and investment tax credits (114) (9) 300 Non-cash rate reduction bond expense 82 66 32 Gain on disposition of assets -- (22) -- Changes in other assets 123 (142) (152) Changes in other liabilities 46 5 (18) Changes in working capital components: Accounts receivable 6 66 (55) Due to/from affiliates -- net (61) (3) (6) Inventories 23 (20) -- Income taxes 114 163 (149) Other current assets (6) 7 (3) Accounts payable 21 (268) 252 Regulatory balancing accounts 89 426 213 Other current liabilities (5) 25 27 --------- -------------~~

~~Net cash provided by operating activities 757 557 174 -------- --------------~~

~~CASH FLOWS FROM INVESTING ACTIVITIES~~

~~Capital expenditures (400) (307) (324) Loan to/from affiliate - net (199) (33) 593 Net proceeds from sale of assets -- 42 24 Contributions to decommissioning funds (5) (5) (5) Other - net (7) (7) -------- -------------------- ----- Net cash provided by (used in) investing activities (611) (310) 288 --------------- -------- CASH FLOWS FROM FINANCING ACTIVITIES Dividends paid (206) (156) (406) Payments on long-term debt (103) (118) (149) Issuances of long-term debt -- 93 12 ---------- -------------------- -- Net cash used in financing activities (309) (181) (543) -------------------------- Increase (decrease) in cash and cash equivalents (163) 66 (81) Cash and cash equivalents, January 1 322 256 337 ---------------------------~~

~~Cash and cash equivalents, December 31 $ 159 $ 322 $ 256 ======= ======= ======= SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION Interest payments, net of amounts capitalized $ 71 $ 83 $ 113 ======= ======= ======= Income tax payments (refunds) - net $ 92 $ (11) $ (8) ======= ======= ======= SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING~~

~~ACTIVITIES Property, plant and equipment contribution from Sempra Energy $ 86 $ -- $ -- ======= ======= =======~~

~~See notes to Consolidated Financial Statements.~~

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
For the years ended December 31, 2002, 2001 and 2000
(Dollars in millions)

Preferred Stock Accumulated Not Subject Other Total Comprehensive to Mandatory Common Retained Comprehensive Shareholders' Income Redemption Stock Earnings Income(Loss) Equity - --

Balance at December 31, 1999 $ 79 $ 857 $ 460 $ (3) $1,393 Net income/comprehensive income $ 151 151 151 Common stock dividends declared ===== (400) (400) Preferred dividends declared (6) (6)

Balance at December 31, 2000 79 857 205 (3) 1,138 Net income/comprehensive income $ 183 183 183 Common stock dividends declared ===== (150) (150) Preferred dividends declared (6) (6)

Balance at December 31, 2001 79 857 232 (3) 1,165 Net income $ 209 209 209 Other comprehensive income adjustment pension (31) (31) (31) ----- Comprehensive income $ 178 Preferred dividends declared ===== (6) (6) Common stock dividends declared (200) (200) Capital contribution 86 86

Balance at December 31, 2002 $ 79 $ 943 $ 235 $ (34) $1,223

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Business Combination

Sempra Energy was formed as a holding company for Enova Corporation (Enova), the parent corporation of San Diego Gas & Electric (SDG&E), and Pacific Enterprises (PE), the parent corporation of Southern California Gas Company (SoCalGas), 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 SDG&E and its sole subsidiary, SDG&E Funding LLC. All material intercompany accounts and transactions have been eliminated.

As a subsidiary of Sempra Energy, the company receives certain services therefrom, for which it is charged its allocable share of the cost of such services. Management believes that cost is reasonable, but probably less than if the company had to provide those services itself.

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 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 company prepares its 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 10 and 11.

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2002, represent net payables (payables net of receivables) of $394 million and $575 million at December 31, 2002 and 2001, 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. Additional information on regulatory matters is included in Notes 10 and 11.

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
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

* In connection with electric industry restructuring, which is described in Note 10, 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	$ 134	$ 158
Noncurrent regulatory assets	1,111	1,638
Current regulatory liabilities*	(2)	(1)
Total	$1,243	$1,795

* Included in other current liabilities

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 $3 million, $5 million and $5 million at December 31, 2002, 2001 and 2000, respectively. The company recorded a provision for doubtful accounts of $4 million, $9 million and $6 million in 2002, 2001 and 2000, respectively.

Inventories

At December 31, 2002, inventory included natural gas of $9 million, and materials and supplies of $37 million. The corresponding balances at December 31, 2001 were $34 million and $36 million, respectively. Natural gas is valued by the last-in first-out (LIFO) method. When the inventory is consumed, differences between this LIFO valuation and replacement cost will be reflected in customer rates. Materials and supplies at SDG&E are generally valued at the lower of average cost or market.

Utility Plant

Utility plant primarily represents the buildings, equipment and other facilities used by the company 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.

Utility plant balances by major functional categories are as follows:

	Utility Plant at December 31		Depreciation rates for years ended December 31		
(Dollars in billions)	2002	2001	2002	2001	2000
Natural gas operations	$ 1.0	$ 1.0	3.62%	3.71%	3.79%
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	0.5	0.3	9.37%	8.46%	8.33%
Total	$ 5.4	$ 5.0			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $0.6 billion and $2.2 billion, respectively, at December 31, 2002, and were $0.5 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 10 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 $21 million, $9 million and $8 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 the company'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.

Revenues

Revenues 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 10 for a discussion of the electric industry restructuring. 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."

Related Party Transactions - Loans to Unconsolidated Affiliates

SDG&E has a promissory note receivable from Sempra Energy which bears a variable interest rate based on short-term commercial paper rates, and is due on demand. The note balance was $250 million and $52 million at December 31, 2002 and 2001, respectively. At December 31, 2001, the "Due from unconsolidated affiliates" account balance also included $24 million of offsetting working capital balances with Sempra Energy affiliates. In addition, at December 31, 2002, SDG&E had $42 million due from and $3 million due to Sempra Energy affiliates. SDG&E also had $16 million and $5 million in non-current liabilities due to Sempra Energy at December 31, 2002 and 2001, respectively.

New Accounting Standards

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 4.

As of January 1, 2003, the company had additional asset retirement obligations estimated to be $12 million associated with the retirement of a former power plant.

SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets": In August 2001, the Financial Accounting Standards Board (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 7 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 the 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.

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, the company did not have any outstanding guarantees.

Other Accounting Standards: During 2002 and 2001 the FASB and the Emerging Issues Task Force (EITF) issued several statements that are currently not applicable to the company. In July 2001, the FASB issued SFAS 142, "Goodwill and Other Intangible Assets," which addresses how intangible assets that are acquired individually or with a group of other assets (but not those acquired in a business combination) should be accounted for in financial statements upon their acquisition. 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. 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. In October 2002, the EITF reached a consensus to rescind EITF Issue 98-10, "Accounting for Energy Trading Contracts," the basis for mark-to-market accounting used for recording energy-trading activities. In January 2003, the FASB issued Interpretation 46, "Consolidation of Variable Interest Entities," which addresses consolidation by business enterprises of variable interest entities.

NOTE 2. SHORT-TERM BORROWINGS

At December 31, 2002, SDG&E and its affiliate, SoCalGas, 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 SDG&E'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 SDG&E 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, SDG&E had no commercial paper outstanding.

NOTE 3. LONG-TERM DEBT

(Dollars in millions)	December 31, 2002	2001
First-mortgage bonds		
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
6.4% and 7% December 1, 2027	225	225
8.5% April 1, 2022	--	10
7.625% June 15, 2002	--	28
	636	674
Unsecured long-term debt		
5.9% June 1, 2014	130	130
Variable rates (1.75% at December 31, 2002) July 1, 2021	39	39
Variable rates (2.00% at December 31, 2002) December 1, 2021	60	60
6.75% March 1, 2023	25	25
	254	254
Rate-reduction bonds, 6.19% to 6.37% at December 31, 2002 payable annually through 2007	329	395
	1,219	1,323
Less:		
Current portion of long-term debt	66	93
Unamortized discount on long-term debt	--	1
Total	$1,153	$1,229

Maturities of long-term debt are $66 million in 2003, $66 million in 2004, $66 million in 2005, $66 million in 2006, $66 million in 2007 and $889 million 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 2), it is assumed the bonds will be held to maturity for purposes of determining the maturities listed above.

First-mortgage Bonds

The first-mortgage bonds are secured by a lien on SDG&E's utility plant. SDG&E may issue additional first-mortgage bonds upon compliance with the provisions of its bond indenture, which requires, 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 $2.1 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 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.

Callable Bonds

At SDG&E'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 SDG&E's remaining callable bonds, $460 million are callable in 2003, $25 million in 2004, and $105 million in 2005.

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 10. 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.

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 $254 million are unsecured at December 31, 2002.

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. 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 8.

Financial Covenants

SDG&E's first-mortgage bond indenture requires 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 2 discusses the financial covenants applicable to short-term debt.

NOTE 4. 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:

(Dollars in millions)

Project	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 2002	Qualified Trust 2001	Nonqualified Trust 2002	Nonqualified Trust 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 10 and 12.

NOTE 5. INCOME TAXES

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

Years ended December 31	2002	2001	2000
Statutory federal income tax rate	35.0%	35.0%	35.0%
Depreciation	2.3	5.9	6.6
State income taxes - net of federal income tax benefit	6.1	5.8	8.5
Tax credits	(0.9)	(0.9)	(1.5)
Settlement of Internal Revenue Service audit	(8.6)	--	--
Other - net	(3.6)	(2.3)	0.2
Effective income tax rate	30.3%	43.5%	48.8%

The components of income tax expense are as follows:

(Dollars in millions)	2002	2001	2000
Current			
Federal	$ 164	$ 120	$(115)
State	41	30	(41)
Total current taxes	205	150	(156)
Deferred			
Federal	(93)	7	244
State	(18)	(13)	59
Total deferred taxes	(111)	(6)	303
Deferred investment tax credits - net	(3)	(3)	(3)
Total income tax expense	$ 91	$ 141	$ 144

Federal and state income taxes are allocated between operating income and other income. SDG&E is included in the consolidated income tax return of Sempra Energy and is allocated income tax expense from Sempra Energy in an amount equal to that which would result from having always filed a separate return.

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	$ 552	$ 391
Regulatory balancing accounts	212	432
Loss on reacquired debt	22	24
Other	85	75
Total deferred tax liabilities	871	922
Deferred tax assets:		
Investment tax credits	29	31
Other	187	124
Total deferred tax assets	216	155
Net deferred income tax liability	$ 655	$ 767

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

(Dollars in millions)	2002	2001
Current liability	$ 53	$ 128
Noncurrent liability	602	639
Total	$ 655	$ 767

NOTE 6. EMPLOYEE BENEFIT PLANS

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 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, the company 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, the company participated in another voluntary separation program. As a result, the company recorded a $5 million special termination benefit.

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:

Other Pension
Benefits
Postretirement
Benefits ----

- (Dollars in
millions)
2002 2001
2002 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%
4.00% 4.00%
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 $
448 $ 477 $
45 $ 49
Service cost
16 13 1 1
Interest cost
40 32 4 3
Plan
amendments --
-- (7) --
Actuarial
(gain) loss
62 4 9 (5)
Transfer of
liability (2)
109 -- 11 --
Curtailments
-- (7) -- --
Settlements -
- 1 -- --
Special
termination
benefits --
13 -- --
Benefits paid
(62) (85) (3)
(3) ---------

~~Net obligation at December 31 613 448 60 45~~

~~CHANGE IN PLAN ASSETS: Fair value of plan assets at January 1 465 604 24 22~~

~~Actual return on plan assets (53) (55) -- 1~~

~~Employer contributions -- -- 3 4~~

~~Transfer of assets (2) 118 1 4 --~~

~~Benefits paid (62) (85) (3) (3)~~

~~Fair value of plan assets at December 31 468 465 28 24~~

~~Plan assets net of obligation at December 31 (145) 17 (32) (21)~~

~~Unrecognized net actuarial (gain) loss 79 (62) 6 (6)~~

~~Unrecognized prior service cost 11 13 (9)~~

~~Net recorded liability at December 31 $ (55) $ (32) $ (35) $ (27)~~

~~(1) Decreasing to ultimate trend of 6.50% in 2004. (2) To reflect transfer of plan assets and liability from Sempra Energy. The following table provides the~~

~~amounts recognized on the Consolidated Balance Sheets (under deferred credits and other liabilities) at December 31: Other Pension Benefits Postretirement Benefits~~

~~(Dollars in millions) 2002 2001 2002 2001~~

~~Accrued benefit cost $ (55) $ (32) $ (35) $ (27)~~

~~Additional minimum liability (52)~~

~~Intangible asset 11~~

~~Accumulated other comprehensive income, pretax 41~~

~~Net recorded liability $ (55) $ (32) $ (35) $ (27)~~

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	$ 16	$ 13	$ 10	$ 1	$ 1	$ 1
Interest cost	40	32	36	4	3	3
Expected return on assets	(43)	(42)	(57)	(1)	(1)	(1)
Amortization of:						
Transition obligation	—	—	—	1	2	2
Prior service cost	2	3	3	(1)	—	—
Actuarial (gain) loss	—	(7)	(17)	—	—	—
Special termination benefits	—	13	5	—	—	1
Curtailment cost	—	1	—	—	1	—
Settlement credit	—	(19)	—	—	—	—
Regulatory adjustment	—	—	—	1	1	(2)
Total net periodic benefit cost (income)	$ 15	$ (6)	$ (20)	$ 5	$ 7	$ 4

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	$ --	$ --
Effect on the health-care component of the accumulated other postretirement benefit obligation	$ 3	$ (2)

The company's funded pension plan had plan assets less than accumulated benefit obligations. 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 and medical benefits for retirees and their spouses.

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 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 Sempra Energy common stock and must remain so invested until termination of employment. At the direction of the employees, the employees' contributions are invested in Sempra Energy stock, mutual funds, or institutional trusts. Company contributions to the savings plans were $7 million in 2002, $5 million in 2001 and $5 million in 2000.

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 7. 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 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, Sempra Energy and its subsidiaries adopted only its disclosure requirements and continue 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.

The subsidiaries record an expense for the plans to the extent that subsidiary employees participate in the plans, or that subsidiaries are allocated a portion of Sempra Energy's costs of the plans. SDG&E recorded expenses of $1 million, $2 million and $1 million in 2002, 2001 and 2000, respectively.

NOTE 8. FINANCIAL INSTRUMENTS

Fair Value

The fair values of certain of the company's financial instruments (cash, temporary investments, 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:

(Dollars in millions)	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
First mortgage bonds	$ 636	$ 689	$ 674	$ 704
Rate reduction bonds	329	357	395	411
Other long-term debt	254	273	254	265
Total long-term debt	$1,219	$1,319	$1,323	$1,380

~~Preferred stock $ 104 $ 98 $ 104 $ 98~~

The fair values of long-term debt and preferred stock 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.

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 the prices to be charged to its 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 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 are not recoverable or payable through future rates, the company applies 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	$ 2	$ 1
Total	2	1
Current liabilities	59	84
Noncurrent liabilities	579	634
Total	638	718
Net liabilities	$ 636	$ 717
Regulatory assets and liabilities:		
Current regulatory assets	$ 59	$ 83
Noncurrent regulatory assets	579	634
Total	638	717
Current regulatory liabilities	2	1
Net regulatory assets	$ 636	$ 716

$1 million in income and $1 million in losses were recorded in 2002 and 2001, respectively, 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. 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.

Energy Derivatives

SDG&E 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 SDG&E to predict with greater certainty the effective prices to be received and the prices to be charged to their customers. See Note 1 for discussion of how these derivatives are classified under SFAS 133.

Energy Contracts

SDG&E records 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 majority of the company's contracts result in physical delivery.

There was no impact on the Statements of Consolidated Income for changes in the fair value of derivative instruments, other than the $1 million gain and $1 million loss for the years ended December 31, 2002 and 2001, respectively, from the interest-rate swap noted above.

NOTE 9. PREFERRED STOCK

(Dollars in millions, except call price)	Call Price	December 31, 2002	December 31, 2001
~~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~~		~~$ 79~~	~~$ 79~~

~~Subject to mandatory redemption Without par value, $1.7625 Series, 1,000,000 shares outstanding $ 25.00 $ 25 $ 25~~

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.

NOTE 10. 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 also described above 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.

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 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. 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 their contracts be determined under a "public interest" standard that requires the complainants to satisfy a significantly higher standard of review to invalidate the contracts 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.

NOTE 11. 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 SDG&E 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; 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 SDG&E. The CPUC modified the settlement to provide increased protection against the exercise of market power by persons who would acquire rights on the SoCalGas 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.

SDG&E believes that 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 SDG&E's 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 PBR has resulted in modification to the general rate case and certain other regulatory proceedings for SDG&E. 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 SDG&E 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. 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. SDG&E's in effect through December 31, 2003, at which time the mechanism will be updated. That update will include, among other things, a reexamination of SDG&E's reasonable costs of operation to be allowed in rates.

An October 10, 2001 decision denied SDG&E's 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 company's net income by $11 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.

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 10 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.

Demand Side Management (DSM) and Energy Efficiency Awards

Since the 1990s, the IOUs have been eligible to earn awards for implementing and/or administering energy-conservation programs. SDG&E has offered these programs to customers and has 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.

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 IOU's DSM programs. The review may include reanalyzing the uncollected portion of past rewards earned by IOUs (which have not been included in SDG&E's 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	
PBR	$ 12.2
Natural gas procurement	6.7
DSM	35.5
Total	$ 54.4

Cost of Capital

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.

SDG&E is 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. SDG&E is 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. SDG&E filed its 2003 BCAP on October 5, 2001. In February 2003, a CPUC Administrative Law Judge granted a motion to defer the BCAP. SDG&E must submit an amended application by September 2003, with new rates scheduled to be implemented by September 2004.

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 SDG&E and SoCalGas. 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 SDG&E and SoCalGas 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 12. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

SDG&E buys 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. SDG&E transports natural gas under long-term firm pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates.

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.

All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a short-term transportation agreement. In addition, under a separate agreement expiring in March 2003, SoCalGas provides SDG&E 4.5 billion cubic feet of storage capacity. An agreement is expected to be completed with SoCalGas that will extend storage services through March 2004.

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

(Dollars in millions)	Storage and Transportation	Natural Gas	Total
2003	$ 14	$ 17	$ 31
2004	14	--	14
2005	13	--	13
2006	12	--	12
2007	11	--	11
Thereafter	153	--	153
Total minimum payments	$ 217	$ 17	$ 234

Total payments under natural gas contracts were $205 million in 2002, $457 million in 2001 and $273 million 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 10.

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 allocation) 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

SDG&E has operating leases 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 3 percent to 5 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 SDG&E. 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)	
2003	$16
2004	14
2005	12
2006	10
2007	6
Thereafter	17
Total future rental commitments	$75

Rent expense for operating leases totaled $27 million in 2002, $21 million in 2001 and $32 million in 2000.

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. 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 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 $4 million in 2002, $1 million in 2001 and $2 million in 2000. The cost of compliance with these regulations over the next five years is not expected to be significant.

Costs that relate to current operations or an existing condition caused by past operations are generally recorded as a regulatory asset due to the assurance that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of its manufactured-gas sites (three completed as of December 31, 2002 and site-closure letters received for two), 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 $14.8 million, of which $1.5 million related to manufactured-gas sites, $12.1 million to cleanup at SDG&E's former fossil-fueled power plants, $0.9 million to waste-disposal sites used by the company (which has been identified as a PRP) and $0.3 million to other hazardous waste sites. These accruals 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 is set for trial in January 2004. During the fourth quarter of 2002, additional similar lawsuits have been filed in various jurisdictions.

SDG&E and two other subsidiaries of Sempra Energy, 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 subsidiary is 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, SDG&E has denied using any of these strategies. It 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, it has also denied engaging in "wash" or "round trip" trading activities.

SDG&E is also cooperating with the FERC and other governmental agencies and officials in their various investigations of the California energy markets. Management believes that this matter 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 company grants credit to customers and counterparties, substantially all of whom are located in its service territories, which covers all of San Diego County and an adjacent portion of Orange County.

As discussed in Note 10, 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.

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarters ended Dollars in millions	March 31	June 30	September 30	December 31
2002				
Operating revenues	$ 427	$ 407	$ 420	$ 442
Operating expenses	358	340	356	380
Operating income	$ 69	$ 67	$ 64	$ 62
Net income	$ 55	$ 52	$ 48	$ 54
Dividends on preferred stock	2	1	2	1
Earnings applicable to common shares	$ 53	$ 51	$ 46	$ 53
2001				
Operating revenues	$ 1,129	$ 511	$ 333	$ 389
Operating expenses	1,056	454	271	360
Operating income	$ 73	$ 57	$ 62	$ 29
Net income	$ 54	$ 38	$ 45	$ 46
Dividends on preferred stock	2	1	2	1
Earnings applicable to common shares	$ 52	$ 37	$ 43	$ 45

The sum of the quarterly amounts does not necessarily equal the annual totals due to rounding.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required on Identification of Directors is incorporated by reference from "Election of Directors" in the Information Statement prepared for the May 2003 annual meeting of shareholders. The information required on the company's executive officers is provided below.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age*	Position
Edwin A. Guiles	53	Chairman and Chief Executive Officer
Debra L. Reed	46	President and Chief Financial Officer
James P. Avery	46	Senior Vice President, Electric Transmission
Steven D. Davis	46	Senior Vice President, Customer Service and External Relations
Margot A. Kyd	49	Senior Vice President, Corporate Business Solutions
Roy M. Rawlings	58	Senior Vice President, Distribution Operations
William L. Reed	50	Senior Vice President, Regulatory Affairs
Lee M. Stewart	57	Senior Vice President, Gas Transmission
Terry M. Fleskes	46	Vice President and Controller

* As of December 31, 2002.

Except for Mr. Avery, each Executive Officer has been an officer or employee of Sempra Energy or one of its subsidiaries for more than five years. Prior to joining SDG&E in 2001, Mr. Avery was a consultant with R.J. Rudden Associates. Except for Mr. Avery, each executive officer of San Diego Gas & Electric Company holds the same position at Southern California Gas Company.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference from "Election of Directors" and "Executive Compensation" in the Information Statement prepared for the May 2003 annual meeting of shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 is incorporated by reference from "Share Ownership" in the Information Statement prepared for the May 2003 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

ITEM 14. CONTROLS AND PROCEDURES.

The company has designed and maintains disclosure controls and procedures to ensure that information required to be disclosed in the company's reports under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and is accumulated and communicated to the company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating these controls and procedures, management recognizes that any system of controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired objectives and necessarily applies judgment in evaluating the cost-benefit relationship of other possible controls and procedures. In addition, the company has investments in unconsolidated entities that it does not control or manage and, consequently, its disclosure controls and procedures with respect to these entities are necessarily substantially more limited than those it maintains with respect to its consolidated subsidiaries.

Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company within 90 days prior to the date of this report has evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures. Based on that evaluation, the company's Chief Executive Officer and Chief Financial Officer have concluded that the controls and procedures are effective.

There have been no significant changes in the company's internal controls or in other factors that could significantly affect the internal controls subsequent to the date the company completed its evaluation.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. Financial statements

2. Financial statement schedules

Other schedules for which provision is made in Regulation S-X are not required under the instructions contained therein, are inapplicable or the information is included in the Consolidated Financial Statements and notes thereto.

3. Exhibits

See Exhibit Index on page 89 of this report.

(b) Reports on Form 8-K

The following reports on Form 8-K were filed after September 30, 2002:

None.

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Numbers 33-45599, 33-52834, 333-52150, and 33-49837 on Form S-3 of our report dated February 14, 2003, appearing in this Annual Report on Form 10-K of San Diego Gas and Electric Company for the year ended December 31, 2002.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 25, 2003

SIGNATURES

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

SAN DIEGO GAS & ELECTRIC COMPANY

By: /s/ Edwin A. Guiles

Edwin A. Guiles
Chairman and Chief Executive Officer

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

Name/Title	Signature	Date
~~Principal Executive Officer:~~		
~~Edwin A. Guiles Chairman and Chief Executive Officer~~	~~/s/ Edwin A. Guiles~~	~~February 17, 2003~~
~~Principal Financial Officer:~~		
~~Debra L. Reed President and Chief Financial Officer~~	~~/s/ Debra L. Reed~~	~~February 17, 2003~~
~~Principal Accounting Officer:~~		
~~Terry M. Fleskes Vice President and Controller~~	~~/s/ Terry M. Fleskes~~	~~February 17, 2003~~
~~Directors:~~		
~~Edwin A. Guiles Chairman~~	~~/s/ Edwin A. Guiles~~	~~February 17, 2003~~
~~Debra L. Reed, Director~~	~~/s/ Debra L. Reed~~	~~February 17, 2003~~
~~Frank H. Ault, Director~~	~~/s/ Frank H. Ault~~	

EXHIBIT INDEX

The Forms 8-K, 10-K and 10-Q referred to herein were filed under Commission File Number 1-3779 (SDG&E), Commission File Number 1-11439 (Enova Corporation, Commission File Number 1-14201 (Sempra Energy) and/or Commission File Number 333-30761 (SDG&E Funding LLC).

Exhibit 1 -- Underwriting Agreements

1.01 Underwriting Agreement dated December 4, 1997 (Incorporated by reference from Form 8-K filed by SDG&E Funding LLC on December 23, 1997 (Exhibit 1.1)).

Exhibit 3 -- Bylaws and Articles of Incorporation

Bylaws

3.01 Restated Bylaws of San Diego Gas & Electric as of November 6, 2001.

Articles of Incorporation

3.02 Amended and Restated Articles of Incorporation of San Diego Gas & Electric Company (Incorporated by reference from the SDG&E Form 10-Q for the three months ended March 31, 1994 (Exhibit 3.1)).

Exhibit 4 -- Instruments Defining the Rights of Security Holders, Including Indentures

The Company agrees to furnish a copy of each such instrument to the Commission upon request.

4.01 Mortgage and Deed of Trust dated July 1, 1940. (Incorporated by reference from SDG&E Registration No. 2-49810, Exhibit 2A.)

4.02 Second Supplemental Indenture dated as of March 1, 1948. (Incorporated by reference from SDG&E Registration No. 2-49810, Exhibit 2C.)

4.03 Ninth Supplemental Indenture dated as of August 1, 1968. (Incorporated by reference from SDG&E Registration No. 2-68420, Exhibit 2D.)

4.04 Tenth Supplemental Indenture dated as of December 1, 1968. (Incorporated by reference from SDG&E Registration No. 2-36042, Exhibit 2K.)

4.05 Sixteenth Supplemental Indenture dated August 28, 1975. (Incorporated by reference from SDG&E Registration No. 2-68420, Exhibit 2E.)

4.06 Thirtieth Supplemental Indenture dated September 28, 1983. (Incorporated by reference from SDG&E Registration No. 33-34017, Exhibit 4.3.)

Exhibit 10 -- Material Contracts

10.01 Restated Letter Agreement between San Diego Gas & Electric Company and the California Department of Water Resources dated April 5, 2001 (2001 Sempra Energy Form 10-K, Exhibit 10.04).

10.02 Transition Property Purchase and Sale Agreement dated December 16, 1997 (Incorporated by reference from Form 8-K filed by SDG&E Funding LLC on December 23, 1997, Exhibit 10.1).

10.03 Transition Property Servicing Agreement dated December 16, 1997 (Incorporated by reference from Form 8-K filed by SDG&E Funding LLC on December 23, 1997, Exhibit 10.2).

Compensation

10.04 Sempra Energy Executive Incentive Plan effective January 1, 2003 (2002 Sempra Energy Form 10-K, Exhibit 10.09).

10.05 Amended Sempra Energy Retirement Plan for Directors (2002 Sempra Energy Form 10-K, Exhibit 10.10).

10.06 Amended and Restated Sempra Energy Deferred Compensation and Excess Savings Plan (Sempra Energy September 30, 2002 Form 10-Q, Exhibit 10.3).

10.07 Form of Sempra Energy Severance Pay Agreement for Executives (2001 Sempra Energy Form 10-K, Exhibit 10.07).

10.08 Sempra Energy Executive Security Bonus Plan effective January 1, 2001 (2001 Sempra Energy Form 10-K, Exhibit 10.08).

10.09 Sempra Energy Deferred Compensation and Excess Savings Plan effective January 1, 2000 (2000 Sempra Energy Form 10-K, Exhibit 10.07).

10.10 Sempra Energy 1998 Long Term Incentive Plan (Incorporated by reference from the Registration Statement on Form S-8 Sempra Energy Registration No. 333-56161 dated June 5, 1998(Exhibit 4.1)).

Financing

10.11 Loan agreement with the City of Chula Vista in connection with the issuance of $25 million of Industrial Development Bonds, dated as of October 1, 1997 (Enova 1997 Form 10-K, Exhibit 10.34).

10.12 Loan agreement with the City of Chula Vista in connection with the issuance of $38.9 million of Industrial Development Bonds, dated as of August 1, 1996 (1996 Form 10-K, Exhibit 10.31).

10.13 Loan agreement with the City of Chula Vista in connection with the issuance of $60 million of Industrial Development Bonds, dated as of November 1, 1996 (1996 Form 10-K, Exhibit 10.32).

10.14 Loan agreement with City of San Diego in connection with the issuance of $57.7 million of Industrial Development Bonds, dated as of June 1, 1995 (June 30, 1995 SDG&E Form 10-Q, Exhibit 10.3).

10.15 Loan agreement with the City of San Diego in connection with the issuance of $92.9 million of Industrial Development Bonds 1993 Series C dated as of July 1, 1993 (June 30, 1993 SDG&E Form 10-Q, Exhibit 10.2).

10.16 Loan agreement with the City of San Diego in connection with the issuance of $70.8 million of Industrial Development Bonds 1993 Series A dated as of April 1, 1993 (March 31, 1993 SDG&E Form 10-Q, Exhibit 10.3).

10.17 Loan agreement with the City of San Diego in connection with the issuance of $118.6 million of Industrial Development Bonds dated as of September 1, 1992 (Sept. 30, 1992 SDG&E Form 10-Q, Exhibit 10.1).

10.18 Loan agreement with the City of Chula Vista in connection with the issuance of $250 million of Industrial Development Bonds, dated as of December 1, 1992 (1992 SDG&E Form 10-K, Exhibit 10.5).

10.19 Loan agreement with the California Pollution Control Financing Authority in connection with the issuance of $129.82 million of Pollution Control Bonds, dated as of June 1, 1996 (1996 Form 10-K, Exhibit 10.41).

10.20 Loan agreement with the California Pollution Control Financing Authority in connection with the issuance of $60 million of Pollution Control Bonds dated as of June 1, 1993 (June 30, 1993 SDG&E Form 10-Q, Exhibit 10.1).

10.21 Loan agreement with the California Pollution Control Financing Authority, dated as of December 1, 1991, in connection with the issuance of $14.4 million of Pollution Control Bonds (1991 SDG&E Form 10-K, Exhibit 10.11).

Nuclear

10.22 Uranium enrichment services contract between the U.S. Department of Energy (DOE assigned its rights to the U.S. Enrichment Corporation, a U.S. government-owned corporation, on July 1, 1993) and Southern California Edison Company, as agent for SDG&E and others; Contract DE-SC05-84UEO7541, dated November 5, 1984, effective June 1, 1984, as amended (1991 SDG&E Form 10-K, Exhibit 10.9).

10.23 Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station, approved November 25, 1987 (1992 SDG&E Form 10-K, Exhibit 10.7).

10.24 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.23 herein)(1994 SDG&E Form 10-K, Exhibit 10.56).

10.25 Second Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.23 herein)(1994 SDG&E Form 10-K, Exhibit 10.57).

10.26 Third Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.23 herein)(1996 Form 10-K, Exhibit 10.59).

10.27 Fourth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.23 herein)(1996 Form 10-K, Exhibit 10.60).

10.28 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.23 herein)(1999 Form 10-K, Exhibit 10.26).

10.29 Sixth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.23 herein)(1999 Form 10-K, Exhibit 10.27).

10.30 Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station, approved November 25, 1987 (1992 SDG&E Form 10-K, Exhibit 10.8).

10.31 First Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.30 herein)(1996 Form 10-K, Exhibit 10.62).

10.32 Second Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.30 herein)(1996 Form 10-K, Exhibit 10.63).

10.33 Third Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.30 herein)(1999 Form 10-K, Exhibit 10.31).

10.34 Fourth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.30 herein)(1999 Form 10-K, Exhibit 10.32).

10.35 Second Amended San Onofre Operating Agreement among Southern California Edison Company, SDG&E, the City of Anaheim and the City of Riverside, dated February 26, 1987 (1990 SDG&E Form 10-K, Exhibit 10.6).

10.36 U. S. Department of Energy contract for disposal of spent nuclear fuel and/or high-level radioactive waste, entered into between the DOE and Southern California Edison Company, as agent for SDG&E and others; Contract DE-CR01-83NE44418, dated June 10, 1983 (1988 SDG&E Form 10-K, Exhibit 10N).

Natural Gas Transportation and Storage

10.37 Master Services Contract, Schedule J, Transaction Based Storage Service Agreement dated April 1, 2002 and expiring March 31, 2003 between San Diego Gas & Electric Company and Southern California Gas Company.

10.38 Master Services Contract (Intrastate Transmission Service), dated July 1, 1998 (month to month) between San Diego Gas & Electric Company and Southern California Gas Company. (1998 10-K, Exhibit 10.64)

10.39 Amendment to Firm Transportation Service Agreement, dated December 2, 1996, between Pacific Gas and Electric Company and San Diego Gas & Electric Company (1997 Enova Corporation Form 10-K Exhibit 10.58).

10.40 Firm Transportation Service Agreement, dated December 31, 1991 between Pacific Gas and Electric Company and San Diego Gas & Electric Company (1991 SDG&E Form 10-K, Exhibit 10.7).

10.41 Firm Transportation Service Agreement, dated October 13, 1994 between Pacific Gas Transmission Company and San Diego Gas & Electric Company (1997 Enova Corporation Form 10-K, Exhibit 10.60).

Other

10.42 Lease agreement dated as of March 25, 1992 with CarrAmerica Development and Construction as lessor of an office complex at Century Park (1994 SDG&E Form 10-K, Exhibit 10.70).

Exhibit 12 -- Statement Re: Computation Of Ratios

12.01 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for the years ended December 31, 2002, 2001, 2000, 1999 and 1998.

Exhibit 21 - Subsidiaries

21.01 Schedule of Subsidiaries at December 31, 2002.

Exhibit 23 - Independent Auditors' Consent, page 87.

GLOSSARY

AB X1	A California Assembly bill authorizing the California Department of Water Resources to purchase energy for California consumers.
AB	California Assembly Bill
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
BCAP	Biennial Cost Allocation Proceeding
Bcf	Billion Cubic Feet (of natural gas)
CEC	California Energy Commission
COS	Cost of Service
CPUC	California Public Utilities Commission
DA	Direct Access
DOE	Department of Energy
DSM	Demand Side Management
DWR	Department of Water Resources
Edison	Southern California Edison Company
EITF	Emerging Issues Task Force
EMFs	Electric and Magnetic Fields
Enova	Enova Corporation
ERMG	Energy Risk Management Group
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
ICIP	Incremental Cost Incentive Pricing mechanism
Intertie	Pacific Intertie
IOUs	Investor-Owned Utilities
ISO	Independent System Operator
kWh	Kilowatt Hour
LIFO	Last-in first-out inventory costing method
mmbtu	Million British Thermal Units (of natural gas)
MOU	Memorandum of Understanding

mW	Megawatt
NRC	Nuclear Regulatory Commission
ORA	Office of Ratepayers Advocates
Parent	Enova Corporation
PBR	Performance-Based Ratemaking/Regulation
PE	Pacific Enterprises
PG&E	Pacific Gas and Electric Company
PGA	Purchased Gas Balancing Account
PGE	Portland General Electric Company
PRP	Potentially Responsible Party
PX	Power Exchange
QFs	Qualifying Facilities
RD&D	Research, Development and Demonstration
ROE	Return on Equity
ROR	Rate of Return
S&P	Standard & Poor's
SB	California Senate Bill
SDG&E	San Diego Gas & Electric Company
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
Southwest Powerlink	A transmission line connecting San Diego to Phoenix and intermediate points.
TCBA	Transition Cost Balancing Account
TURN	The Utility Reform Network
UEG	Utility Electric Generation
VaR	Value at Risk

CERTIFICATIONS

I, Edwin A. Guiles, certify that:

1. I have reviewed this Annual Report on Form 10-K of San Diego Gas & Electric Company;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements and other financial information included in this Annual Report fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this Annual Report (the "Evaluation Date"); and

c) presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this Annual Report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

February 26, 2003

/s/ Edwin A. Guiles
Edwin A. Guiles
Chief Executive Officer

I, Debra L. Reed, certify that:

1. I have reviewed this Annual Report on Form 10-K of San Diego Gas & Electric Company;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements and other financial information included in this Annual Report fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this Annual Report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this Annual Report (the "Evaluation Date"); and

c) presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this Annual Report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

February 26, 2003

/s/ Debra L. Reed
Debra L. Reed
Chief Financial Officer

EXHIBIT 12.1

SAN DIEGO GAS & ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES
AND PREFERRED STOCK DIVIDENDS
(Dollars in millions)

	1998	1999	2000	2001	2002
Fixed Charges and Preferred Stock Dividends:					
Interest	$118	$131	$119	$ 96	$ 83
Interest portion of annual rentals	7	5	3	3	4
Total Fixed Charges	125	136	122	99	87
Preferred Stock Dividends(1)	11	10	13	11	9
Combined Fixed Charges and Preferred Stock Dividends For Purpose of Ratio	$136	$146	$135	$110	$ 96
Earnings:					
Pretax income from continuing operations	$332	$325	$295	$324	$300
Total Fixed charges (from above)	125	136	122	99	87
Less: Interest capitalized	1	1	3	1	1
Total Earnings for Purpose					

~~of Ratio~~
~~$456 $460~~
~~$414 $422~~
~~$386~~
~~========~~
~~========~~
~~========~~
~~========~~
~~========~~
~~Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends~~
~~3.35 3.15~~
~~3.07 3.84~~
~~4.02~~
~~========~~
~~========~~
~~========~~
~~========~~
~~========~~
~~(1) In computing this ratio, "Preferred dividends" represents the before-tax earnings necessary to pay such dividends, computed at the effective tax rates for the applicable periods.~~

EXHIBIT 21.01

SAN DIEGO GAS & ELECTRIC COMPANY
Schedule of Subsidiaries at December 31, 2002

Subsidiary	State of Incorporation
SDG&E Funding LLC	Delaware