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, 2003

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]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes [X] No [ ]

Exhibit Index on page 88. Glossary on page 94.

Aggregate market value of the voting preferred stock held by non-affiliates of the registrant as of January 31, 2004 was $24.8 million.

Registrant's common stock outstanding as of January 31, 2004 was wholly owned by Enova Corporation.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the Information Statement prepared for the May 2004 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," "could," "would" and "should" or similar expressions, or discussions of strategy or of plans are intended to identify forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future results may differ materially from those expressed in these forward-looking statements.

Forward-looking statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others, local, regional and national 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 status of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; and other uncertainties, all of which are difficult to predict and many of which are beyond the control of the company. Readers are cautioned not to rely unduly on any forward-looking statements and are urged to review and consider carefully the risks, uncertainties and other factors which affect the company's business described in this report and other reports filed by the company from time to time with the Securities and Exchange Commission.

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 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.

RISK FACTORS

The following risk factors and all other information contained in this report should be considered carefully when evaluating SDG&E. These risk factors could affect the actual results of SDG&E and cause such results to differ materially from those expressed in any forward-looking statements of, or made by or on behalf of, SDG&E. Other risks and uncertainties, in addition to those that are described below, may also impair its business operations. If any of the following risks occurs, SDG&E's business, cash flows, results of operations and financial condition could be seriously harmed. These risk factors should be read in conjunction with the other detailed information concerning SDG&E set forth in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

SDG&E is subject to extensive regulation by state, federal and local legislation and regulatory authorities, which may adversely affect the operations, performance and growth of its business.

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, rates 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 (including reasonableness and prudency reviews) and conducts audits and investigations into various matters which may, from time to time, result in disallowances and penalties adversely affecting earnings and cash flows. The CPUC also regulates the relationship of utilities with their affiliates and is currently conducting an investigation into this relationship. Various proceedings involving the CPUC and relating to SDG&E's rates, costs, incentive mechanisms, performance-based regulation and affiliate and holding company rule compliance are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

Periodically SDG&E's rates are approved by the CPUC based on forecasts of capital and operating costs. If SDG&E's actual capital and operating costs were to exceed the amount included in its base rates approved by the CPUC, it would adversely affect earnings and cash flows.

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted Performance-Based Regulation (PBR) effective in 1994. 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.

Although SDG&E has received significant PBR rewards in the past, there can be no assurance that SDG&E will receive rewards at similar levels in the future, or at all. Additionally, if SDG&E fails to achieve certain minimum performance levels established under the PBR mechanisms, it may be assessed financial disallowances or penalties which could adversely affect its earnings and cash flows.

The FERC regulates the transmission and wholesale sales of electricity in interstate commerce, transmission access and other similar matters involving SDG&E.

SDG&E may be impacted by new regulations, decisions, orders or interpretations of the CPUC, FERC or other regulatory bodies. New legislation, regulations, decisions, orders or interpretations could change how SDG&E operates, could affect its ability to recover its various costs through rates or adjustment mechanisms, or could require SDG&E to incur additional expenses.

SDG&E may incur substantial costs and liabilities as a result of its ownership of nuclear facilities.

SDG&E owns a 20% interest in the San Onofre Nuclear Generating Station (SONGS), a 2,150 megawatt nuclear generating facility near San Clemente, California. The Nuclear Regulatory Commission has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. SDG&E's ownership interest in SONGS subjects it to the risks of nuclear generation, which include:

- -- the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;

- -- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and

- -- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

SDG&E's future results of operations, cash flows and financial condition may be materially adversely affected by the outcome of pending litigation against it.

Lawsuits filed in 2000 and currently consolidated in San Diego Superior Court seek class-action certification and damages, alleging Sempra Energy and the California Utilities, along with El Paso Energy Corp. and several of its affiliates, unlawfully sought to control natural gas markets. Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada and by others. Although the California Utilities expect to prevail in these cases, they have expended or accrued substantial amounts to pay the costs of defending these claims. If the plaintiffs in these cases were to prevail in their claims, the future results of operations, cash flows and financial condition of the company may be materially adversely affected. In addition, various other lawsuits are pending against SDG&E and other Sempra Energy subsidiaries alleging that the companies unlawfully manipulated the electric energy market.

In December 2002, the CPUC approved a settlement with SDG&E allocating between SDG&E's customers and shareholders the profits from certain intermediate-term power purchase contracts that SDG&E had entered into during the early stages of California's electric utility industry restructuring. As a result of the CPUC's decision, SDG&E recognized additional after-tax income of $65 million in 2003. The Utility Consumers' Action Network (UCAN) has appealed the decision and the California Court of Appeals granted the petition for review.

These proceedings are discussed in the notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein.

SDG&E's cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its utility operations.

SDG&E's utility operations are its major source of liquidity. SDG&E's cash flows, ability to meet its obligations to creditors and its ability to pay dividends on its common stock are largely dependent upon the sufficiency of utility earnings and cash flows in excess of utility needs.

Natural disasters, catastrophic accidents or acts of terrorism could materially adversely affect SDG&E's business, earnings and cash flows.

Like other major industrial facilities, SDG&E's SONGS nuclear facility, electric transmission facilities, and natural gas pipelines may be damaged by natural disasters, catastrophic accidents or acts of terrorism. Any such incidents could result in severe business disruptions, significant decreases in revenues and/or significant additional costs to the company, which could have a material adverse affect on SDG&E's earnings and cash flows. Given the nature and location of these facilities, any such incidents also could cause fires, leaks, explosions, spills or other significant damage to natural resources and/or property belonging to third parties, or personal injuries, which could lead to significant claims against the company and its subsidiaries. Insurance coverage may become unavailable for certain of these risks and the insurance proceeds received for any loss of or damage to any of its facilities, or for any loss of or damage to natural resources or property or personal injuries caused by its operations, may be insufficient to cover the company's losses or liabilities without materially adversely affecting the company's financial condition, earnings and cash flows.

GOVERNMENT REGULATION

California Utility Regulation

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.

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 the CPUC are currently investigating prices charged to the California investor-owned utilities (IOUs) by various suppliers of natural gas and electricity. See further discussion in Notes 10 and 11 of the notes to Consolidated Financial Statements herein.

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.

Local Regulation

SDG&E has electric franchises with the two counties and the 26 cities in its electric service territory, and natural gas franchises with the one county and the 18 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 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). The franchise agreement with the city of Chula Vista expired during 2003 but continues on a month-to-month basis and a new agreement is being negotiated.

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.

ELECTRIC OPERATIONS

Customers

At December 31, 2003 the company had 1.3 million meters consisting of 1,150,000 residential, 136,000 commercial, 450 industrial, 1,800 street and highway lighting, 8,000 direct access and 24 off-system. The company's service area covers 4,100 square miles. The company added 18,000 new customer meters in 2003 and 20,000 in 2002, representing growth rates of 1.4% and 1.6% respectively.

Resource Planning and Power Procurement

SDG&E's resource planning, power procurement and related regulatory matters are discussed below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 10 to Consolidated Financial Statements herein.

Electric Resources

Based on CPUC-approved purchased-power contracts currently in place with SDG&E's various suppliers and SDG&E's 20-percent share of a generating plant, as of December 31, 2003, the supply of electric power available to SDG&E is as follows:

Supplier	Source	Expiration date	Megawatts (MW)
Generation: SONGS			430
Purchased power contracts:			
Long-term contracts:			
Portland General Electric (PGE)	Coal	December 2013	84
DWR-allocated contracts:			
Williams Energy Marketing & Trading	Natural gas	December 2010	1,875
Sunrise Power Co. LLC	Natural gas	June 2012	572
Other	Natural gas/wind	2004 to 2013	328
Total			2,775
Other contracts with Qualifying Facilities (QFs):			
Applied Energy Inc.	Cogeneration	November 2019	107
Yuma Cogeneration	Cogeneration	May 2024	57
Goal Line Limited Partnership	Cogeneration	February 2025	50
Other (73 contracts)	Cogeneration	Various	16
Total			230
Other contracts with renewable sources:			
Various (9 contracts)	Bio-gas	5-15 year terms starting in 2003	28
Various (1 contract)	Bio-mass	5 year term starting in 2003	49
Various (5 contracts)	Wind	10-15 year terms starting in 2003	159
Total sources			236
Total generation and contracted			3,755

Under the contract with PGE, SDG&E pays a capacity charge plus a charge based on the amount of energy received and or PGE's costs. Costs under the contracts with QFs are based on SDG&E's avoided cost. Charges under the remaining contracts 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.

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 it down. The storage and decommissioning of Unit 1's spent nuclear fuel 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.

SDG&E has fully recovered its SONGS capital investment through December 31, 2003.

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, 11 and 12 of the notes to Consolidated Financial Statements herein.

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 is expected to be adequate at least 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 $3 million per year. The DOE projects that it will not begin accepting spent fuel until 2010 at the earliest.

To the extent not currently provided by the contracts, 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.

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 280 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 Independent System Operator(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 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. In 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.

NATURAL GAS OPERATIONS

Resource Planning and Natural Gas Procurement and Transportation

SDG&E is engaged in the sale and distribution of natural gas. The company's resource planning, natural gas procurement, contractual commitments and related regulatory matters are discussed below and in "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.

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 electric generation (EG), wholesale, large commercial, industrial and enhanced oil recovery customers.

Most core customers purchase natural gas directly from the company. Core customers are permitted to aggregate their natural gas requirement and purchase directly from brokers or producers. SDG&E continues to be obligated to purchase reliable supplies of natural gas to serve the requirements of the core customers.

Natural Gas Procurement and Transportation

Most of the natural gas purchased and delivered by SDG&E is produced outside of California, primarily in the southwestern U.S. and Canada. SDG&E purchases natural gas under short-term primarily based on monthly spot-market prices.

SDG&E has long-term natural gas transportation contracts with various interstate pipelines which expire on various dates through 2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues to evaluate its long-term pipeline capacity portfolio, including 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 authorized by the CPUC. In addition, under a separate agreement expiring March 2005, SoCalGas provides SDG&E 8 bcf of storage inventory capacity with firm injection and withdrawal rights.

According to "Btu's Daily Gas Wire," the annual average spot price of natural gas at the California/Arizona border was $5.10 per million British thermal unit (mmbtu) in 2003 ($5.59 in December 2003), compared with $3.14 per mmbtu in 2002 and $7.27 per mmbtu in 2001. A number of 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 and in 2003. The following table summarizes the average commodity costs of natural gas sold for the last three years, which are above previous levels:

	Years ended December 31,		
	2003	2002	2001
Cost of natural gas	$ 274	$ 205	$ 457
Volumes delivered (bcf)	49	50	52
Average cost of natural gas (dollars per bcf)	$ 5.59	$ 4.10	$ 8.79

With improved delivery capacity to California, the company expects adequate resources to be available at prices that generally will follow national natural gas pricing trends and volatility.

Demand for Natural Gas

SDG&E faces competition in the residential and commercial customer markets based on the customers' preferences for natural gas compared with other energy products. The demand for natural gas by electric generators is influenced by a number of factors. In the short-term, natural gas use by EGs is impacted by the availability of alternative sources of generation. The availability of hydroelectricity is highly dependent on precipitation in the western United States. In addition, natural gas use is impacted by the performance of other generation sources in the western United States, including nuclear and coal, and other natural gas facilities outside the service area. Natural gas use is also impacted by changes in end-use electricity demand. For example, natural gas use generally increases during summer heat waves. Over the long-term, natural gas use will be greatly influenced by additional factors such as the location of new power plant construction. More generation capacity currently is being constructed outside Southern California than within the utility service area. This new generation will likely displace the output of older, less efficient local generation, reducing EG natural gas use.

Effective March 31, 1998, electric industry restructuring provided out-of-state producers the option to purchase energy for California utility customers. 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 SDG&E'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 electric generation from SDG&E's service area.

Growth in the natural gas markets is largely dependent upon the health and expansion of the Southern California economy and prices of other energy products. 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 company added 11,000 and 14,000 new customer meters in 2003 and 2002, respectively, representing growth rates of 1.4 percent and 1.8 percent, respectively. The company expects that its growth rate for 2004 will approximate that for 2003.

In the interruptible industrial market, customers are capable of burning a fuel other than natural gas. Fuel oil is the most significant competing energy alternative. The company's ability to maintain its industrial market share is largely dependent on price. The relationship between natural gas supply and demand has the greatest impact on the price of the company's product. With the reduction of natural gas production from domestic sources, the cost of natural gas from non-domestic sources may play a greater role in the company's competitive position in the future. The price of oil depends upon a number of factors beyond the company's control, including the relationship between supply and demand, and policies of foreign and domestic governments.

The natural gas distribution business is seasonal in nature as variations in weather conditions generally result in greater revenues during the winter months when temperatures are colder. As is prevalent in the industry, the company injects natural gas into storage during the summer months (usually April through October) for withdrawal storage during the winter months (usually November through March) when customer demand is higher.

RATES AND REGULATION

Information concerning rates and regulations applicable to the company is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 1, 10 and 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 notes to 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. 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. Cleanup costs at sites related to electric generation were specifically excluded from the collaborative by the CPUC.

During the early 1900s, SDG&E and its predecessors manufactured gas from coal or oil. The manufactured-gas plants (MGPs) often have become contaminated with the hazardous residues of the process. SDG&E identified three former MGPs, 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, 2003 estimated remaining remediation liability on the third site is $5.8 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. Total costs to perform the necessary remediation were estimated at $11 million at the time of sale. 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 commenced in 2003 and is expected to be completed by 2005. In 2003, at a cost of $0.8 million, cleanup was completed at the site of a power plant that was sold in 1999. Remaining costs to remediate these sites are estimated at $8 million at December 31, 2003.

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, 2003, the company's estimated remaining investigation and remediation liability related to hazardous waste sites, including the MGPs, was $6.8 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 previously 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 kelp 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 $34.0 million. These mitigation projects are expected to be completed in 2007. Through December 31, 2003, SONGS mitigation costs were recovered through the ICIP mechanism. SONGS mitigation costs incurred after December 31, 2003, will be capitalized and recovered from ratepayers over the remaining life of the SONGS units, subject to CPUC approval in Edison's general rate case. Additional information on SONGS cost recovery is provided in Note 10 of the notes to Consolidated Financial Statements herein.

OTHER MATTERS

Research, Development and Demonstration (RD&D)

For 2003, the CPUC authorized SDG&E to fund $1.2 million and $5.6 million for its natural gas and electric RD&D programs, respectively, including $5.6 million to the CEC for its PIER (Public Interest Energy Research) Program. SDG&E's annual RD&D costs have averaged $5.7 million over the past three years.

Employees of Registrant

As of December 31, 2003 the company had 4,441 employees, compared to 4,130 at December 31, 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 interest in SONGS is described in "Electric Resources" herein. At December 31, 2003, 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 1,805 miles of transmission lines and 21,353 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

Natural Gas Properties

At December 31, 2003, 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, 7,806 miles of high and low pressure distribution mains, and 6,094 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.

The company 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 is 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	2003	2002	2001	2000	1999
Income Statement Data:					
Operating revenues	$ 2,311	$ 1,725	$ 2,362	$ 2,671	$ 2,207
Operating income	$ 381	$ 262	$ 221	$ 235	$ 281
Dividends on preferred stock	$ 6	$ 6	$ 6	$ 6	$ 6
Earnings applicable to common shares	$ 334	$ 203	$ 177	$ 145	$ 193
Balance Sheet Data:					
Total assets	$ 6,463	$ 6,285	$ 6,542	$ 5,843	$ 5,427
Long-term debt	$ 1,087	$ 1,153	$ 1,229	$ 1,281	$ 1,418
Short-term debt (a)	$ 66	$ 66	$ 93	$ 66	$ 66
Preferred stock subject to mandatory redemption (b)	$ --	$ 25	$ 25	$ 25	$ 25
Shareholders' equity	$ 1,343	$ 1,223	$ 1,165	$ 1,138	$ 1,393

(a) Includes long-term debt due

~~within one year. (b) At December 31, 2003, $21 million of mandatorily redeemable preferred stock was reclassified to Deferred Credits and Other Liabilities and $3 million was reclassified to Other Current Liabilities.~~

Since SDG&E 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 2001 through 2003, 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 in this Financial Report.

The company is an operating public utility engaged in the electric and natural gas businesses, and provides services to 3.2 million consumers. 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 800,000 meters in San Diego County and transports electricity and natural 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. SDG&E and an affiliate, Southern California Gas Company (SoCalGas), are collectively referred to herein as "the California Utilities."

RESULTS OF OPERATIONS

2003 was a successful year for the company. Net income was $340 million, a company record. This is discussed further in the following pages.

The following chart shows net income for each of the last five years.

(Dollars in millions)

	Net Income
2003	$ 340
2002	$ 209
2001	$ 183
2000	$ 151
1999	$ 199

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

The company is subject to various regulatory bodies and rules at the national, state and local levels. The primary California body is the California Public Utilities Commission (CPUC), which regulates utility rates and operations. The primary national bodies are the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC). The FERC regulates interstate transportation of natural gas and electricity and various related matters. The NRC regulates nuclear generating plants. Local regulators and municipalities govern the placement of utility assets, including natural gas pipelines and electric lines.

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

Beginning on January 1, 2003, SDG&E and the other IOUs resumed their electric commodity procurement function. In addition, the CPUC established the allocation of the power purchased by the DWR under long-term contracts for the IOUs' customers and the related cost responsibility among the IOUs for that power. This is discussed further in Note 10 of the notes to Consolidated Financial Statements.

The natural gas industry experienced an initial phase of restructuring during the 1980s by deregulating natural gas sales to noncore customers. Restructuring is again being considered, as discussed in Note 11 of the notes to Consolidated Financial Statements.

See additional discussion of these matters under "Factors Influencing Future Performance" and in Notes 10 and 11 of the notes to Consolidated Financial Statements.

Electric Revenue and Cost of Electric Fuel and Purchased Power. Electric revenues increased to $1.8 billion in 2003 from $1.3 billion in 2002, and the cost of electric fuel and purchased power increased to $0.5 billion in 2003 from $0.3 billion in 2002. Additionally, for the fourth quarter electric revenues increased to $424 million in 2003 from $332 million in 2002, and the cost of electric fuel and purchased power increased to $113 million in 2003 from $76 million in 2002. These changes were attributable to several factors, including the effect of the DWR's purchasing the net short position of SDG&E during 2002, higher electric commodity costs and volumes in 2003, and the increase in authorized 2003 distribution revenue. In addition, the increase in revenue was due to the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts and higher PBR awards during the third quarter or 2003. See discussion of performance awards in Note 11 of the notes to Consolidated Financial Statements.

Electric revenues decreased to $1.3 billion in 2002 from $1.7 billion in 2001, and the cost of electric fuel and purchased power decreased to $0.3 billion in 2002 from $0.8 billion in 2001. These decreases were primarily due to the DWR's purchasing SDG&E's net short position for a full year in 2002 and the effect of lower electric commodity costs and decreased off-system sales. For the fourth quarter, electric revenues increased to $332 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 resulting from increased volumes, 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 Natural Gas. Natural gas revenues increased to $509 million in 2003 from $431 million in 2002, and the cost of natural gas increased to $274 million in 2003 from $205 million in 2002. Additionally, natural gas revenues increased to $138 million for the three months ended December 31, 2003 from $122 million for the corresponding period in 2002, and the cost of natural gas increased to $75 million in 2003 from $56 million in 2002. These changes were primarily attributable to natural gas price increases. For the year, this was partially offset by reduced volumes.

Under the current regulatory framework, the cost of natural gas purchased for customers and the variations in that cost are passed through to the customers on a substantially concurrent basis. However, SDG&E's natural gas procurement Performance-Based Regulation (PBR) mechanism provides an incentive mechanism by measuring SDG&E's procurement of natural gas against a benchmark price comprised of monthly natural gas indices, resulting in shareholder rewards for costs achieved below the benchmark and shareholder penalties when costs exceed the benchmark. See further discussion in Notes 1 and 11 of the notes to Consolidated Financial Statements.

Natural gas revenues decreased to $431 million in 2002 from $686 million in 2001, and the cost of natural gas 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 North Baja pipeline's beginning of service in September 2002 and to the lower level of electric generation demand.

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

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

	2003		2002		2001	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
Residential	6,702	$ 731	6,266	$ 649	6,011	$ 775
Commercial	6,263	674	6,053	633	6,107	753
Industrial	1,987	162	1,893	161	2,792	325
Direct access	3,322	87	3,448	117	2,464	84
Street and highway lighting	91	11	88	9	89	10
Off-system sales	8	—	5	—	413	88
	18,373	1,665	17,753	1,569	17,876	2,035
Balancing and other		137		(275)		(359)
Total						

~~$ 1,802 $ 1,294 $ 1,676~~

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

Natural Gas Sales Transportation & Exchange Total

Volumes Revenue Volumes Revenue Volumes Revenue

~~2003: Residential 32 $ 291 $ 32 $ 291 Commercial and industrial 17 127 4 5 21 132 Electric generation plants 3 62 30 62 33 49 $ 421 66 $ 35 115 456 Balancing accounts and other 53 Total $ 509~~

~~2002: Residential 33 $ 246 $ 1 33 $ 247 Commercial and industrial 17 98 5 7 22 105 Electric generation plants~~

~~85 24 85 24~~

~~50~~
~~$ 344 90 $ 32~~
~~140 376~~
~~Balancing accounts and other 55~~
~~Total $ 431~~

~~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~~

As explained in Note 1 of the notes to Consolidated Financial Statements commodity-related revenues from the DWR's purchasing of the company's net short position or from the DWR's allocated contracts are not included in revenue. However, the associated volumes and distribution revenue are included herein.

Other Operating Expenses. Other operating expenses increased to $637 million in 2003 from $560 million in 2002 and increased to $209 million in the fourth quarter of 2003 from $176 million in the fourth quarter of 2002. The changes were due primarily to higher labor and employee benefit costs, costs associated with the Southern California wildfires and general operating cost increases, including litigation charges. Other operating expenses increased to $560 million in 2002 from $491 million in 2001. For the fourth quarter, other operating expenses increased to $176 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 SONGS.

Other Income. Other income and deductions, which primarily consist of interest income and/or expense from short-term investments and regulatory balancing accounts, was $32 million, $24 million and $54 million in 2003, 2002 and 2001, respectively. Other income for the fourth quarter, was $21 million, $10 million and $38 million in 2003, 2002 and 2001, respectively. The increases in 2003 were due to higher interest income resulting from the favorable $37 million before-tax resolution of income-tax issues with the Internal Revenue Service (IRS) and reduced balancing account interest expense in 2003. The decreases in 2002 were primarily due to 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.

Interest Expense. Interest expense was $73 million, $77 million and $92 million in 2003, 2002 and 2001, respectively. The decrease for the year in 2003 was due primarily to lower interest incurred as the result of lower average debt. The decrease in interest expense in 2002 was primarily due to lower average debt and lower interest rates in 2002. For the fourth quarter, interest expense was $20 million, $18 million and $22 million in 2003, 2002, and 2001, respectively. 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 $148 million, $91 million and $141 million for the years ended December 31, 2003, 2002 and 2001, respectively. The effective income tax rates were 30.3 percent, 30.3 percent and 43.5 percent for the same years. The increased income tax expense in 2003 compared to 2002 was due primarily to higher taxable income while the low rate in 2003 was due primarily to a $57 million favorable resolution of income-tax issues in the fourth quarter of 2003. In addition, income before taxes in 2003 included $37 million in interest income arising from the income tax settlement, resulting in an offsetting $15 million income tax expense. The lower income tax expense in 2002 compared to 2001 was due to lower taxable income and a $25 million favorable resolution of prior years' income-tax issues in 2002, while the low rate in 2002 was due to the $25 million favorable resolution.

Net Income. SDG&E recorded net income of $340 million and $209 million in 2003 and 2002, respectively, and net income of $130 million and $54 million for the fourth quarters of 2003 and 2002, respectively. The increase for the year was primarily due to the favorable resolution of income tax issues in the fourth quarter of 2003, which positively affected earnings by $79 million, income of $65 million after-tax related to the approved settlement of certain purchase power contracts (see Note 10 of the notes to Consolidated Financial Statements), higher earnings from PBR awards, and higher electric transmission and distribution revenue. These factors were partially offset by higher operating expenses (including litigation charges in the third quarter of 2003), the end of sharing of the merger savings (which positively impacted earnings by $8 million in 2002) and the $25 million favorable resolution of prior years' income tax issues recorded in the second quarter of 2002. The change for the quarter was due to the resolution of the income tax issues and higher electric transmission and distribution revenue, offset partially by the end of sharing of the merger savings (which positively impacted earnings by $2 million for the 2002 quarter).

Net income increased to $209 million in 2002 from $183 million in 2001. The increase was primarily due to the $25 million after-tax benefit noted above and lower interest expense in 2002, partially offset by lower interest income in 2002 and the 2001 gain on the sale of SDG&E's Blythe property. Net income increased to $54 million for the fourth quarter of 2002, compared to $46 million for the corresponding period in 2001, primarily due to higher natural gas income, an increase in electric transmission and distribution revenues, and income tax adjustments in 2002, partially offset by the 2001 Blythe gain.

CAPITAL RESOURCES AND LIQUIDITY

The company's operations are the major source of liquidity. At December 31, 2003, the company had $148 million in cash and $300 million in available unused, committed lines of credit.

Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $581 million, $757 million and $557 million for 2003, 2002 and 2001, respectively.

The decrease in cash flows from operations in 2003 compared to 2002 was attributable to a decrease in overcollected regulatory balancing accounts and higher tax payments, partially offset by a reduction in deferred income taxes and investment tax credits.

The increase in cash flows from operations in 2002 compared to 2001 was attributable to higher customer refunds and payments of accounts payable in 2001, partially offset by the decrease in overcollected regulatory balancing accounts and higher deferred income taxes and investment tax credits in 2002.

During 2003, the company made a pension plan contribution of $17 million for the 2003 plan year.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $319 million, $611 million and $310 million for 2003, 2002 and 2001, respectively.

The decrease in cash used in investing activities in 2003 compared to 2002 was primarily due to the $129 million repayment by Sempra Energy in 2003 compared to $199 million of advances from SDG&E in 2002. Advances to Sempra Energy are payable on demand.

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.

Capital Expenditures for Utility Plant

Capital expenditures were $444 million in 2003, compared to $400 million and $307 million in 2002 and 2001, respectively. The increase in capital expenditures in 2003 was mainly due to the inclusion of $40 million of capital costs associated with the Southern California wildfires in October 2003. Capital expenditures in 2002 were up due to additions and improvements to the company's natural gas and electric distribution systems.

Future Capital Expenditures

Significant capital expenditures in 2004 are expected to be for additions to the company's natural gas and electric distribution systems. These expenditures are expected to be financed by cash flows from operations and security issuances.

Over the next five years, the company expects to make capital expenditures of $2.7 billion, consisting of $400 million in 2004, $450 million in 2005, $1.0 billion in 2006, $400 million in 2007 and $450 million in 2008.

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.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash used in financing activities totaled $273 million, $309 million and $181 million for 2003, 2002 and 2001, respectively.

The cash used in financing activities decreased in 2003 due to lower repayments on long-term debt in 2003.

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.

Long-Term and Short-Term Debt

Repayments on long-term debt in 2003 were for $66 million of rate-reduction bonds.

Repayments on long-term debt in 2002 included $38 million of first-mortgage bonds and $66 million of rate-reduction bonds.

In 2001, repayments on long-term debt consisted of $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.

See Notes 2 and 3 of the notes to Consolidated Financial Statements for further discussion of debt activity and lines of credit.

Dividends

Dividends paid to Sempra Energy amounted to $200 million in 2003, compared to $200 million in 2002 and $150 million in 2001.

The payment of future dividends and the amount thereof are within the discretion of the company's board of directors. The CPUC's regulation of SDG&E's capital structure limits the amounts that are available for loans and dividends to Sempra Energy from SDG&E. At December 31, 2003, the company could have provided a total (combined loans and dividends) of $290 million to Sempra Energy. At December 31, 2003, SDG&E had actual loans, net of payables, to Sempra Energy of $75 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, 2003 was $2.2 billion. The debt-to-capitalization ratio was 40 percent at December 31, 2003. Significant changes in capitalization during 2003 included long-term borrowings and repayments, income and dividends.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2003. 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 3, 4, 9 and 12 of the notes to Consolidated Financial Statements.

By Period - ------------------------------------
-------------------------------------- 2005
2007 (Dollars in millions) and and Description
2004 2006 2008 Thereafter Total - ----------------

-------------- ~~Long-term debt $ 66 $ 132 $ 65 $~~
~~890 $1,153 Operating leases 17 29 17 23 86~~
~~Purchased-power contracts 214 457 458 2,235 3,364~~
~~Natural gas contracts 20 39 28 142 229 Preferred~~
~~stock subject to mandatory redemption 1 3 20 -- 24~~
~~Construction commitments 12 16 14 48 90 SONGS~~
~~decommissioning 20 22 9 265 316 Asset retirement~~
~~obligations 3 6 1 -- 10 Environmental commitments~~
~~8 9 -- -- 17 -------------------------------------~~
~~-------------- Totals $ 361 $ 713 $ 612 $3,603~~
~~$5,289~~
~~==~~

Credit Ratings

Several credit ratings of the company declined in 2003, but remain investment grade. As of January 31, 2004, 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	BBB+	Baa1	A+
Commercial paper	A-1	P-1	F1+

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

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

FACTORS INFLUENCING FUTURE PERFORMANCE

Performance of the company will depend primarily on the ratemaking and regulatory process, electric and natural gas industry restructuring, and the changing energy marketplace. These factors are discussed in Notes 10 and 11 of the notes to Consolidated Financial Statements herein.

Electric Industry Restructuring and Electric Rates

Subsequent to the electric capacity shortages of 2000-2001, SDG&E's service territory had and continues to have an adequate supply of electricity. However, various projections of electricity demand in SDG&E's service territory indicate that, without additional electrical generation and transmission, and reductions in electrical usage, beginning in 2005 electricity demand could begin to outstrip available resources. SDG&E has issued a request for proposals (RFP) to meet the electric capacity shortfall, estimated at 69 megawatts (MW) in 2005 and increasing annually by approximately 100 MW, and has filed a proposed plan at the CPUC for meeting these capacity requirements. See Note 10 of the notes to Consolidated Financial Statements for additional information regarding the RFP results.

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

See additional discussion of this and related topics, including the CPUC's adjustment to its plan for deregulation of electricity, in Note 10 of the notes to Consolidated Financial Statements.

Natural Gas Restructuring and Rates

In December 2001 the CPUC issued a decision related to natural gas industry restructuring; however, implementation has been delayed. A CPUC decision could be issued in the first quarter of 2004. With the company's natural gas supply contracts nearing expiration, the company believes that regulation needs to consider sufficiently the adequacy and diversity of supplies to California, transportation infrastructure and cost recovery thereof, hedging opportunities to reduce cost volatility, and programs to encourage and reward conservation. Additional information on natural gas industry restructuring is provided in Note 11 of the notes to Consolidated Financial Statements.

CPUC Investigation of Compliance with Affiliate Rules

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

Cost of Service Filing

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases designed to reflect forecasts of 2004 capital and operating costs. SDG&E is requesting revenue increases of $76 million. On December 19, 2003, settlements were filed with the CPUC for SoCalGas and for SDG&E that, if approved, would resolve most of the cost of service issues. A CPUC decision is likely in the second quarter of 2004. The California Utilities have also filed for continuation through 2004 of existing Performance-Based Regulation mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but deferred action on applying any rewards or penalties for performance relative to these targets to a decision to be issued later in 2004 in a second phase of these applications. This is discussed in Note 11 of the notes to Consolidated Financial Statements.

MARKET RISK

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

Sempra Energy has adopted corporate-wide policies governing its market risk management activities. Assisted by Sempra Energy's Energy Risk Management Group (ERMG), Sempra Energy's Energy Risk Management Oversight Committee (ERMOC), consisting of senior officers, oversees company-wide energy risk management activities and monitors the results of activities to ensure compliance with the company's stated energy risk management policies. Utility management receives daily information on positions and the ERMG receives information 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, ERMOC monitors energy price risk management 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, 2003, the total VaR of the company's natural gas and power positions was not material.

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

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

Commodity Price Risk

Market risk related to physical commodities is created by volatility in the prices and basis of 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, intrastate transportation and storage activity. However, the company may, at times, be exposed to market risk as a result of SDG&E's natural gas PBR and electric procurement activities, 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 framework. As of December 31, 2003, the company's exposure to market risk was not material. However, if commodity prices rose too rapidly, it is likely that volumes would decline. This would increase the per-unit fixed costs, which could lead to further volume declines, leading to increased per-unit fixed costs and so forth.

Interest Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its long-term debt. The company historically has funded operations through long-term debt issues with fixed interest rates and these interest costs are recovered in utility rates. As a result, some recent debt offerings have used a combination of fixed-rate and floating-rate debt. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures when appropriate, based upon market conditions.

At December 31, 2003, the company had $996 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, 2003, SDG&E's fixed-rate debt had a one-year VaR of $149 million and SDG&E's variable-rate debt had a one-year VaR of $0.02 million.

At December 31, 2003, the company did not have any outstanding interest-rate swap transactions. See Note 3 of the notes to Consolidated Financial Statements for further information regarding interest rate swap transactions.

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

Credit Risk

Credit risk is the risk of loss that would be incurred as a result of nonperformance by counterparties of their contractual obligations. As with market risk, the company has adopted corporate-wide policies governing the management of credit risk. Credit risk management is performed by the ERMG and the company's credit department and overseen by the ERMOC. Using rigorous models, the groups continuously calculate current and potential credit risk to counterparties to monitor actual balances in comparison to approved limits and reports this information to the ERMG. The company avoids concentration of counterparties whenever possible and management believes its credit policies with regard to counterparties significantly reduce overall credit risk. These policies include an evaluation of prospective counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances, the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty and other security such as lock-box liens and downgrade triggers.

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.

CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS

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

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

Statement of Financial Accounting Standards (SFAS) No. 5 "Accounting for Contingencies," establishes the amounts and timing of when the company provides for contingent losses. Details of the company's issues in this area are discussed in Note 12 of the notes to Consolidated Financial Statements.

SFAS 71 "Accounting for the Effects of Certain Types of Regulation," has a significant effect on the way the California Utilities record assets and liabilities, and the related revenues and expenses, that would not be recorded absent the principles contained in SFAS 71.

SFAS 109 "Accounting for Income Taxes," governs the way the company provide for income taxes. Details of the company's issues in this area are discussed in Note 5 of the notes to Consolidated Financial Statements.

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

SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" and SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" have a significant effect on the balance sheets of the company but have no significant effect on its 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 receivables, regulatory assets, deferred tax assets and other assets.

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

The likelihood of recovery of various deferred tax assets.

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

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

As discussed elsewhere herein, the company uses exchange quotations or other third-party pricing to estimate fair values whenever possible. When no such data is available, it uses internally developed models and other techniques. The assumed collectibility of receivables considers the aging of the receivables, the creditworthiness of customers and the enforceability of contracts, where applicable. The assumed collectibility of regulatory assets considers legal and regulatory decisions involving the specific items or similar items. The assumed collectibility of other assets considers the nature of the item, the enforceability of contracts where applicable, the creditworthiness of the other parties and other factors. Costs to fulfill contracts that are carried at fair value are based on prior experience. Actuarial assumptions are based on the advice of the company's independent actuaries. The likelihood of deferred tax recovery is based on analyses of the deferred tax assets and the company's expectation of future financial and/or taxable income, based on its strategic planning.

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

Key non-cash performance indicators for the company include numbers of customers and quantities of natural gas and electricity sold. The information is provided in "Introduction" and "Results of Operations."

NEW ACCOUNTING STANDARDS

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

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

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

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, 2003 and 2002, and the related statements of consolidated income, cash flows and changes in shareholders' equity for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of San Diego Gas & Electric Company and subsidiary as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 23, 2004

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED INCOME
(Dollars in millions)
Years ended
December 31,
2003 2002 2001
------ ------ -
----- ~~OPERATING~~
~~REVENUES~~
~~Electric $~~
~~1,802 $ 1,294 $~~
~~1,676 Natural~~
~~gas 509 431 686~~
~~--------- Total~~
~~operating~~
~~revenues 2,311~~
~~1,725 2,362 ---~~
~~------ OPERATING~~
~~EXPENSES Cost~~
~~of electric~~
~~fuel and~~
~~purchased power~~
~~541 297 782~~
~~Cost of natural~~
~~gas 274 205 457~~
~~Other operating~~
~~expenses 637~~
~~560 491~~
~~Depreciation~~
~~and~~
~~decommissioning~~
~~242 230 207~~
~~Income taxes~~
~~122 93 122~~
~~Franchise fees~~
~~and other taxes~~
~~114 78 82 ------~~
~~---- Total~~
~~operating~~
~~expenses 1,930~~
~~1,463 2,141 ---~~
~~------ Operating~~
~~income 381 262~~
~~221 ------------~~
~~Other income~~
~~and~~
~~(deductions)~~
~~Interest income~~
~~42 10 21~~
~~Regulatory~~
~~interest -- net~~
~~(5) (7) 5~~
~~Allowance for~~
~~equity funds~~
~~used during~~
~~construction 12~~
~~15 5 Income~~
~~taxes on non-~~
~~operating~~
~~income (26) 2~~
~~(19) Other --~~
~~net 9 4 42 ------~~
~~----- Total 32~~
~~24 54 ----------~~
~~Interest~~
~~charges Long-~~
~~term debt 67 75~~
~~84 Other 11 8~~
~~12 Allowance~~
~~for borrowed~~
~~funds used~~

~~during construction (5) (6) (4) -------------- -------- Total 73 77 92 -------------- ---------------~~

~~Net income 340 209 183 Preferred dividend requirements 6 6 6 -------------- -------------~~

~~Earnings applicable to common shares $ 334 $ 203 $ 177 ======= ======= ======= See notes to Consolidated Financial Statements.~~

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

-------- 2003
2002 ----------

~~ASSETS Utility plant - at original cost $ 5,773 $ 5,408 Accumulated depreciation and amortization (1,737) (1,613)~~
~~Utility plant - net 4,036 3,795~~
~~Nuclear decommissioning trusts 570 494~~
~~Current assets: Cash and cash equivalents 148 159 Accounts receivable - trade 173 163 Accounts receivable - other 17 18 Interest receivable 37 -- Due from unconsolidated affiliates 151 292 Regulatory assets arising from fixed-price contracts and other derivatives 59 59 Other regulatory assets 81 75 Inventories 60 46 Other 27 11~~
~~Total current assets 753 823~~
~~Other assets: Deferred taxes recoverable in rates 273 190 Regulatory assets arising from fixed-price contracts and other derivatives 502 579 Other regulatory assets 281 342 Sundry 48 62~~
~~Total other assets 1,104 1,173~~
~~Total assets $ 6,463 $ 6,285 ======= ======= See notes to~~

~~Consolidated Financial Statements.~~

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2003	December 31, 2002
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock (255 million shares authorized; 117 million shares outstanding)	$ 938	$ 943
Retained earnings	369	235
Accumulated other comprehensive income (loss)	(43)	(34)
Total common equity	1,264	1,144
Preferred stock not subject to mandatory redemption	79	79
Total shareholders' equity	1,343	1,223
Preferred stock subject to mandatory redemption	--	25
Long-term debt	1,087	1,153
Total capitalization	2,430	2,401
Current liabilities:		
Accounts payable	193	159
Due to unconsolidated affiliates	--	3
Interest payable	10	12
Income taxes payable	30	41
Deferred income taxes	83	53
Regulatory balancing accounts -- net	338	394
Fixed-price contracts and other derivatives	59	59
Current portion of long-term debt	66	66
Other	294	170
Total current liabilities	1,073	957

~~Deferred credits and other liabilities: Due to unconsolidated affiliates 21 16 Customer advances for construction 49 54 Deferred income taxes 617 602 Deferred investment tax credits 40 42 Regulatory liabilities arising from cost of removal obligations 846 1,162 Regulatory liabilities arising from asset retirement obligations 281 -- Fixed price contracts and other derivatives 502 579 Asset retirement obligations 303 -- Mandatorily redeemable preferred securities 21 -- Deferred credits and other liabilities 280 472 -------------- Total deferred credits and other liabilities 2,960 2,927 ------------------ Contingencies and commitments (Note 12) Total liabilities and shareholders' equity $ 6,463 $ 6,285 ======= ======= 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,
2003 2002 2001
------- -------
------- ~~CASH FLOWS FROM OPERATING ACTIVITIES Net income $ 340 $ 209 $ 183 Adjustments to reconcile net income to net cash provided by operating activities: Depreciation and amortization 242 230 207 Customer refunds paid -- -- (127) Deferred income taxes and investment tax credits (7) (114) (9) Non-cash rate reduction bond expense 68 82 66 Loss (gain) on disposition of assets 4 -- (22) Changes in other assets -- 123 (142) Changes in other liabilities (6) 46 5 Changes in working capital components: Accounts receivable (9) 6 66 Interest receivable (37) -- -- Due to/from affiliates -- net 2 (61) (3) Inventories (14) 23 (20) Income taxes (14) 114 163 Other current assets (23) (6) 7 Accounts payable 34 21 (268) Regulatory balancing accounts (56) 89 426 Other current liabilities 57 (5) 25 -------~~

~~Net cash provided by operating activities 581 757 557 -------~~

~~CASH FLOWS FROM~~

~~INVESTING ACTIVITIES Capital expenditures (444) (400) (307) Loan to/from affiliate - net 129 (199) (33) Net proceeds from sale of assets 4 -- 42 Contributions to decommissioning funds (5) (5) (5) Other - net (3) (7) (7) ------- ------- ------- Net cash used in investing activities (319) (611) (310) ------- ------- ------- CASH FLOWS FROM FINANCING ACTIVITIES Dividends paid (206) (206) (156) Payments on long-term debt (66) (103) (118) Redemptions of preferred stock (1) -- -- Issuances of long-term debt -- -- 93 ------- ------- ------- Net cash used in financing activities (273) (309) (181) ------- ------- ------- Increase (decrease) in cash and cash equivalents (11) (163) 66 Cash and cash equivalents, January 1 159 322 256 ------- ------- ------- Cash and cash equivalents, December 31 $ 148 $ 159 $ 322 ======= ======= ======= SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION Interest payments, net of amounts capitalized $ 68 $ 71 $ 83 ======= ======= ======= Income tax payments (refunds) - net $ 167 $ 92 $ (11) ======= ======= ======= SUPPLEMENTAL~~

~~SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES Assets contributed by Sempra Energy $ 1 $ 86 $ -- Liabilities assumed (6) -- ------------------------------------- Net assets (liabilities) contributed by Sempra Energy $ (5) $ 86 $ -- ======= ======= ======= See notes to Consolidated Financial Statements.~~

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2003, 2002 and 2001
(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, 2000 $ 79 $ 857 $ 205 $ (3) $1,138 Net income/comprehensive income $ 183 183 183 ==== Preferred dividends declared (6) (6) Common stock dividends declared (150) (150) 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 Net income $ 340 340 340 Other comprehensive income adjustment - pension (9) (9) (9) ---- Comprehensive income $ 331 ==== Preferred dividends declared (6) (6) Common stock dividends declared (200) (200) Capital contribution (5) (5) Balance at December 31, 2003 $ 79 $ 938 $ 369 $ (43) $1,343
===

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Consolidated Financial Statements include the accounts of San Diego Gas & Electric (SDG&E or the company) 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). SDG&E and its affiliate, Southern California Gas Company (SoCalGas), are collectively referred to herein as "the California Utilities."

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 reductions in future 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" requires that a loss must be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase. Information concerning regulatory assets and liabilities is described in "Revenues," "Regulatory Balancing Accounts," and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2003, represent net payables (payables net of receivables) of $338 million and $394 million at December 31, 2003 and 2002, respectively. The payables normally are returned by reducing future rates.

Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. However, fluctuations in most operating and maintenance costs and in consumption levels affect earnings. 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 and regulatory liabilities as discussed above.

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

(Dollars in millions)	2003	2002
Fixed-price contracts and other derivatives	$ 560	$ 636
Recapture of temporary rate reduction*	259	326
Deferred taxes recoverable in rates	273	190
Unamortized loss on retirement of debt - net	44	49
Employee benefit costs	35	35
Cost of removal obligations**	(846)	(1,162)
Asset retirement obligations**	(303)	--
Other	24	7
Total	$ 46	$ 81

* 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 2007.

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

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

(Dollars in millions)	2003	2002
Current regulatory assets	$ 140	$ 134
Noncurrent regulatory assets	1,056	1,111
Current regulatory liabilities*	(23)	(2)
Noncurrent regulatory liabilities	(1,127)	(1,162)
Total	$ 46	$ 81

* Amount is included in Other Current Liabilities.

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

Cash and Cash Equivalents

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

Collection Allowances

The allowance for doubtful accounts was $2 million, $3 million and $5 million at December 31, 2003, 2002 and 2001, respectively. The company recorded a provision for doubtful accounts of $1 million, $4 million and $9 million in 2003, 2002 and 2001, respectively.

Inventories

At December 31, 2003, inventory shown on the Consolidated Balance Sheets included natural gas of $21 million, and materials and supplies of $39 million. The corresponding balances at December 31, 2002 were $9 million and $37 million, respectively. Natural gas is valued by the last-in first-out (LIFO) method. When the inventory is consumed, differences between the LIFO valuation and replacement cost are reflected in customer rates. Materials and supplies at the company are generally valued at the lower of average cost or market.

Property, Plant and Equipment

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 plant includes labor, materials, contract services and related items. In addition, the cost of plant includes an allowance for funds used during construction (AFUDC). The cost of most retired depreciable utility plant, 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)	2003	2002	2003	2002	2001
Natural gas operations	$ 1.0	$ 1.0	3.63%	3.62%	3.71%
Electric distribution	3.2	3.0	4.70%	4.66%	4.67%
Electric transmission	0.9	0.9	3.09%	3.17%	3.19%
Other electric	0.7	0.5	9.53%	9.37%	8.46%
Total	$ 5.8	$ 5.4			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $0.3 billion and $1.4 billion, respectively, at December 31, 2003, and were $0.3 billion and $1.3 billion, respectively, at December 31, 2002. See discussion of SFAS 143 under "New Accounting Standards." Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. See Note 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 - Net in the Statements of Consolidated Income, although it is not a current source of cash. AFUDC amounted to $17 million, $21 million and $9 million for 2003, 2002 and 2001, respectively.

Nuclear Decommissioning Liability

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

Legal Fees

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

Comprehensive Income

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

Revenues

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

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

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

Transactions with 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 (net of intercompany payables) was $96 million and $259 million at December 31, 2003 and 2002, respectively. In addition, at December 31, 2003 and 2002, SDG&E had $55 million and $33 million due from affiliates, and at December 31, 2002 had $3 million due to affiliates. SDG&E also had $21 million and $16 million in non-current liabilities due to Sempra Energy at December 31, 2003 and 2002, respectively.

New Accounting Standards

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

SFAS 143, "Accounting for Asset Retirement Obligations": SFAS 143, issued in July 2001, addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of long-lived assets, such as nuclear plants. It requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset by the present value of the future retirement cost. Over time, the liability is accreted to its full value and paid, and the capitalized cost is depreciated over the useful life of the related asset.

The adoption of SFAS 143 on January 1, 2003 resulted in the recording of an addition to utility plant of $71 million, representing the company's share of SONGS estimated future decommissioning costs (as discounted to the present value at the dates the units began operation), and accumulated depreciation of $41 million related to the increase to utility plant, for a net increase of $30 million. In addition, the company recorded a corresponding retirement obligation liability of $309 million (which includes accretion of that discounted value to December 31, 2002) and a regulatory liability of $215 million to reflect that SDG&E has collected the funds from its customers more quickly than SFAS 143 would accrete the retirement liability and depreciate the asset. These liabilities, less the $494 million recorded as accumulated depreciation prior to January 1, 2003 (which represents amounts collected for future decommissioning costs), comprise the offsetting $30 million. See further discussion of SONGS' decommissioning and the related nuclear decommissioning trusts in Note 4.

On January 1, 2003, the company recorded additional asset retirement obligations of $10 million associated with the future retirement of a former power plant.

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

Balance as of January 1, 2003	$ --
Adoption of SFAS 143	319
Accretion expense	21
Payments	(14)
Balance as of December 31, 2003	$ 326*

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

Had SFAS 143 been in effect on January 1, 2002, the asset retirement obligation liability would have been $354 million as of that date.

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

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

The company collects estimated removal costs in rates through depreciation in accordance with regulatory treatment. SFAS 143 also requires the company to reclassify estimated removal costs, which have historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2003 and 2002, the estimated removal costs recorded as a regulatory liability were $846 million and $1.2 billion, respectively. The decrease in the amount during 2003 is due to SFAS 143 requiring further reclassification of those costs to a legal obligation (primarily SONGS costs) to Asset Retirement Obligations.

SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets": In August 2001, the 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." It applies to all long-lived assets. Among other things, 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. Adoption of this statement on January 1, 2002 had no impact on the company's financial statements.

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.

Sempra Energy has elected to continue using the intrinsic value method of accounting for stock-based compensation. Therefore, SFAS 148 will not have any effect on the company's financial statements. See Note 7 for additional information regarding stock-based compensation.

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

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

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

FASB Interpretation No. (FIN) 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": In November 2002, the FASB issued FIN 45, which elaborates on the disclosures to be made in interim and annual financial statements of a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing a guarantee. As of December 31, 2003, the company did not have any outstanding guarantees.

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

Other Accounting Standards: During 2003 and 2002 the FASB and the EITF issued several statements that are not applicable to the company but could be in the future. In July 2001, the FASB issued SFAS 142, "Goodwill and Other Intangible Assets." In April 2002, the FASB issued SFAS 145, which rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt", and SFAS 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements." In June 2002, the FASB issued SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 supersedes previous accounting guidance, principally EITF 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." In 2002, consensuses were reached in EITF 02-3 and the rescission of EITF 98-10, both dealing with mark-to-market accounting for energy-trading activities. In January 2003, the FASB issued Interpretation 46, "Consolidation of Variable Interest Entities an interpretation of ARB No. 51."

NOTE 2. SHORT-TERM BORROWINGS

Committed Lines of Credit

SDG&E and its affiliate SoCalGas have a combined revolving line of credit, under which each utility individually may borrow up to $300 million, subject to a combined borrowing limit for both utilities of $500 million. Borrowings under the agreement bear interest at rates varying with market rates and SDG&E's credit rating. The revolving credit commitment expires in May 2004, at which time outstanding borrowings may be converted into a one-year term loan subject to any requisite regulatory approvals related to long-term debt. The agreement requires SDG&E to maintain a debt-to-total capitalization ratio (as defined in the agreement) of not to exceed 60 percent. Borrowings under the agreement are individual obligations of the borrowing utility and a default by one utility would not constitute a default or preclude borrowings by the other. These lines of credit have never been drawn upon.

NOTE 3. LONG-TERM DEBT

(Dollars in millions)	December 31, 2003	2002
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 (1.25% at December 31, 2003) September 1, 2020	58	58
5.85% June 1, 2021	60	60
5.25% to 7% December 1, 2027	225	225
	636	636
Other long-term debt		
5.9% June 1, 2014	130	130
Variable rates (1.46% at December 31, 2003) July 1, 2021	39	39
Variable rates (1.45% at December 31, 2003) December 1, 2021	60	60
6.75% March 1, 2023	25	25
	254	254
Rate-reduction bonds, 6.31% to 6.37% at December 31, 2003 payable annually through 2007	263	329
	1,153	1,219
Current portion of long-term debt	(66)	(66)
Total	$1,087	$1,153

Maturities of long-term debt are $66 million in 2004, 2005 and 2006, $65 million in 2007 and $890 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 credit agreements (which are generally renewed upon expiration and which are described in Note 2), it is expected that the bonds will be held to the maturities stated above.

Callable Bonds

At the company's option, certain bonds are callable at various dates. Of SDG&E's callable bonds, $597 million are callable in 2004, $105 million in 2005 and $45 million thereafter.

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, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of an additional $2.3 billion of first mortgage bonds at December 31, 2003.

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

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

Unsecured Long-term Debt

Various long-term obligations totaling $254 million are unsecured at December 31, 2003.

In February 2001, SDG&E remarketed $25 million of variable-rate unsecured bonds as 6.75 percent fixed-rate debt for a three-year term.

Rate-Reduction Bonds

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

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. As of December 31, 2003, the company did not have any outstanding swap agreements.

During 2002 and 2001, SDG&E had an interest-rate swap agreement that effectively fixed the interest rate on $45 million of variable-rate underlying debt at 5.4 percent. This floating-to-fixed-rate swap did not qualify for hedge accounting and, therefore, the gains and losses associated with the change in fair value are recorded in the Statements of Consolidated Income. The effect on net income was a $1 million gain in 2002 and a $1 million loss in 2001.

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, 2003, are as follows:

(Dollars in millions) Project	SONGS	Southwest Powerlink
Percentage ownership (1)	20%	89%
Utility plant in service	$ 11	$237
Accumulated depreciation and amortization	$ 5	$141
Construction work in progress	$ --	$ 27

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

The amounts specified above for SONGS represent wholly owned substation equipment. As of December 31, 2003, the company has fully recovered its interest in SONGS through the ICIP mechanism, which ended in December 31, 2003. Additional information concerning the ICIP mechanism is provided in Note 10.

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

The company's share of operating expenses is included in the Statements of Consolidated Income.

SONGS Decommissioning

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

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

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

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Several structures, foundations and large components have been dismantled, removed, and disposed of. Preparations have been made for the remaining major work to be performed in 2004 and beyond. That work will include dismantling, removal and disposal of all remaining Unit 1 equipment and facilities (both nuclear and non-nuclear components), decontamination of the site and completion of an on-site storage facility for Unit 1 spent fuel. These activities are expected to be completed in 2008.

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

Nuclear Decommissioning Trusts

SDG&E has established a Nonqualified Nuclear Decommissioning Trust and a Qualified Nuclear Decommissioning Trust to provide funds for the decommissioning of SONGS as described above. Amounts held by these trusts are invested in accordance with CPUC regulations that establish maximum amounts for investments in equity securities (50 percent of the qualified trust and 60 percent of the nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of these trusts must be invested passively.

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

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

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

Additional information regarding SONGS is included in Notes 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, 2003	2002	2001
Statutory federal income tax rate	35.0%	35.0%	35.0%
Depreciation	3.9	2.3	5.9
State income taxes - net of federal income tax benefit	6.4	6.1	5.8
Tax credits	(0.6)	(0.9)	(0.9)
Settlement of Internal Revenue Service audit	(11.7)	(8.6)	--
Other - net	(2.7)	(3.6)	(2.3)
Effective income tax rate	30.3%	30.3%	43.5%

The components of income tax expense are as follows:

(Dollars in millions)	2003	2002	2001
Current			
Federal	$ 122	$ 164	$ 120
State	33	41	30
Total current taxes	155	205	150
Deferred			
Federal	(9)	(93)	7
State	5	(18)	(13)
Total deferred taxes	(4)	(111)	(6)
Deferred investment tax credits	(3)	(3)	(3)
Total income tax expense	$ 148	$ 91	$ 141

On the Statements of Consolidated Income, 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 SDG&E's having always filed a separate return.

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

(Dollars in millions)	2003	2002
Deferred tax liabilities:		
Differences in financial and tax bases of utility plant	$ 699	$ 552
Regulatory balancing accounts	189	212
Loss on reacquired debt	19	22
Other	10	85
Total deferred tax liabilities	917	871
Deferred tax assets:		
Investment tax credits	29	29
Unbilled revenue	--	29
Deferred compensation	76	46
Contingent liabilities	44	44
State income taxes	24	20
Federal benefit of state income taxes	29	24
Other	15	24
Total deferred tax assets	217	216
Net deferred income tax liability	$ 700	$ 655

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

Dollars in millions)	2003	2002
Current liability	$ 83	$ 53
Noncurrent liability	617	602
Total	$ 700	$ 655

Resolution of Certain Internal Revenue Service Matters

The company favorably resolved matters related to various prior years' returns during 2003. The primary issue involving the treatment of utility balancing accounts for the company was resolved following the issuance of an IRS Revenue Ruling and resolution of factual issues involving these claims with the IRS. The total after-tax earnings and future cash flows for all IRS issues was $79 million.

NOTE 6. EMPLOYEE BENEFIT PLANS

Pension and Other Postretirement Benefits

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

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

During 2002, the company had amendments to other postretirement benefit plans related to the transfer of employees to SDG&E from the affiliates, 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, it recorded a $13 million special termination benefit, a $1 million curtailment cost and a $19 million settlement gain.

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

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

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

(Dollars in millions)	Pension Benefits		Other Postretirement Benefits	
	2003	2002	2003	2002
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	$ 613	$ 448	$ 60	$ 45
Service cost	14	16	2	1
Interest cost	40	40	4	4
Actuarial loss	49	62	14	9
Transfer of liability from Sempra Energy	7	109	--	11
Benefit payments	(61)	(62)	(4)	(3)
Plan amendments	--	--	--	(7)
Net obligation at December 31	662	613	76	60

~~----- CHANGE IN PLAN ASSETS: Fair value of plan assets at January 1 468 465 28 24 Actual return on plan assets 107 (53) 3 -- Employer contributions 17 -- 7 3 Transfer of assets from Sempra Energy 7 118 -- 4 Benefit payments (61) (62) (4) (3)~~

~~----- Fair value of plan assets at December 31 538 468 34 28~~

~~----- Benefit obligation net of plan assets at December 31 (124) (145) (42) (32) Unrecognized net actuarial loss 53 79 17 6 Unrecognized prior service cost 9 11 (8) (9)~~

~~--------- Net recorded liability at December 31 $ (62) $ (55) $ (33) $ (35)~~

The following table provides the amounts recognized on the Consolidated Balance Sheets (in Deferred Credits and Other Liabilities) at December 31:

(Dollars in millions)	Pension Benefits 2003	Pension Benefits 2002	Other Postretirement Benefits 2003	Other Postretirement Benefits 2002
Accrued benefit cost	$ (62)	$ (55)	$ (33)	$ (35)
Additional minimum liability	(61)	(52)	—	—
Intangible asset	9	11	—	—
Accumulated other comprehensive income, pretax	52	41		
Net recorded liability	$ (62)	$ (55)	$ (33)	$ (35)

At December 31, 2003, the company's pension plan had benefit obligations in excess of its plan assets. The following table provides certain information for that plan at December 31:

	Projected Benefit Obligation Exceeds the Fair Value of Plan Assets	Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets
(Dollars in		

millions)
2003 2002
2003 2002
- --------

-
~~Projected benefit obligation $ 662 $ 613 $ 662 $ 613 Accumulated benefit obligation $ 661 $ 575 $ 661 $ 575 Fair value of plan assets $ 538 $ 468 $ 538 $ 468~~

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

Other Pension Benefits Postretirement Benefits ----

(Dollars in millions)
2003 2002 2001 2003 2002 2001 - -

~~Service cost $ 14 $ 16 $ 13 $ 2 $ 1 $ 1 Interest cost 40 40 32 4 4 3 Expected return on assets (34) (43) (42) (1) (1) (1) Amortization of: Transition obligation -- -- 1 1 2 Prior service cost 2 2 3 (1) (1) -- Actuarial (gain) loss 2 -- (7) 1 -- -- Special termination benefits -- -- 13 -- -- -- Curtailment~~

~~cost 1~~
~~1~~
~~Settlement credit (19)~~
~~Regulatory adjustment 1 1~~

~~Total net periodic benefit cost (income) $ 24 $ 15 $ (6) $ 6 $ 5 $ 7~~

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

Other Pension
Benefits
Postretirement
Benefits ----

2003 2002
2003 2002 - -

~~WEIGHTED-~~
~~AVERAGE~~
~~ASSUMPTIONS~~
~~USED TO~~
~~DETERMINE~~
~~BENEFIT~~
~~OBLIGATION AS~~
~~OF DECEMBER~~
~~31: Discount~~
~~rate 6.00%~~
~~6.50% 6.00%~~
~~6.50% Rate of~~
~~compensation~~
~~increase~~
~~4.50% 4.50%~~
~~4.50% 4.50%~~
~~WEIGHTED-~~
~~AVERAGE~~
~~ASSUMPTIONS~~
~~USED TO~~
~~DETERMINE NET~~
~~PERIODIC~~
~~BENEFIT COSTS~~
~~FOR YEARS~~
~~ENDED~~
~~DECEMBER 31:~~
~~Discount rate~~
~~6.50% 7.25%~~
~~6.50% 7.25%~~
~~Expected~~
~~return on~~
~~plan assets~~
~~7.50% 8.00%~~
~~3.75% 4.00%~~
~~Rate of~~
~~compensation~~
~~increase~~
~~4.50% 4.50%~~
~~4.50% 4.50% -~~
____
____
____
____
____
____
____

The expected long-term rate of return on plan assets is derived from
historical returns for broad asset classes consistent with
expectations from a variety of sources, including pension consultants
and investment advisors.
2003 2002 - -

~~ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31: Health care cost trend rate 30.00% (1) 7.00% Rate to which the cost trend rate is assumed to decline (the ultimate trend) 5.50% 6.50% Year that the rate reaches the ultimate trend 2008 2004~~

~~(1) This is the weighted average of the increases for all health plans. The 2003 rate for these plans ranged from 15% to 40%. Assumed health care cost trend rates have a significant effect on the amounts reported for the health-care plan costs. A one-percent change in assumed health care cost trend rates would have the following effects:~~

~~(Dollars in millions) 1% Increase 1% Decrease~~

~~Effect on total of service and interest cost components of~~

~~net periodic postretirement health care benefit cost $ — $ —~~
~~Effect on the health care component of the accumulated other postretirement benefit obligation $ 4 $ (3)~~

Pension Plan Investment Strategy

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

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

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

Investment Strategy for Postretirement Health Plans

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

Target Percentage of Plan Allocation Assets at December

31

Asset Category	2004	2003	2002
U.S. Equity	25%	26%	23%
Foreign Equity	5%	5%	4%
Fixed Income	70%	69%	73%
Total	100%	100%	100%

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

Future Payments

The company expects to contribute $23 million to its pension plan and $7 million to its other postretirement benefit plans in 2004.

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

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2004	$ 45	$ 5
2005	$ 46	$ 6
2006	$ 49	$ 6
2007	$ 52	$ 6
2008	$ 55	$ 6
Thereafter	$ 299	$ 32

Savings Plan

The company offers trusteed savings plan to all eligible employees. Eligibility to participate in the plan 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 six 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 or until the employee's attainment of age 55, when they may be transitioned into other investments. At the direction of the employees, the employees' contributions are invested in Sempra Energy stock, mutual funds, or institutional trusts. Company contributions to the savings plan were $8 million in 2003, $7 million in 2002 and $5 million in 2001.

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. See additional discussion of SFAS 148, the amendment to SFAS 123, in Note 1.

Sempra Energy's subsidiaries record an expense for the plans to the extent their 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 $7 million, $1 million and $2 million in 2003, 2002 and 2001, respectively.

NOTE 8. FINANCIAL INSTRUMENTS

Fair Value

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

(Dollars in millions)	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
First mortgage bonds	$ 636	$ 653	$ 636	$ 689
Rate reduction bonds	263	284	329	357
Other long-term debt	254	278	254	273
Total long-term debt	$ 1,153	$ 1,215	$ 1,219	$ 1,319
Preferred stock	$ 103*	$ 100	$ 104	$ 98

~~* $24 million of mandatorily redeemable preferred stock has been reclassified to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets.~~

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

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

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in other comprehensive income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. The ineffective portion is reported in earnings immediately. There was no effect on other comprehensive income for the years ended December 31, 2003 and 2002. In instances where derivatives do not qualify for hedge accounting, gains and losses are recorded in the Statements of Consolidated Income.

The company utilizes energy and natural gas derivatives to manage commodity price risk associated with servicing their load requirements. 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. The use of derivative financial instruments is subject to certain limitations imposed by company policy and regulatory requirements. The company classifies its forward contracts as follows:

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

Electric and Natural Gas Purchases and Sales: The unrealized gains and losses related to these forward contracts are offset against regulatory assets and liabilities on the Consolidated Balance Sheets 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 and the related regulatory asset or liability will be amortized over the remaining contract life.

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

(Dollars in millions)	2003	2002
Fixed-priced contracts and other derivatives:		
Current liabilities	$ 59	$ 59
Noncurrent liabilities	502	579
Total	561	638
Current assets	(1)	(2)
Net liabilities	$ 560	$ 636
Regulatory assets and liabilities:		
Current regulatory assets	$ 59	$ 59
Noncurrent regulatory assets	502	579
Total	561	638
Current regulatory liabilities	(1)	(2)
Net regulatory assets	$ 560	$ 636

The above had no impact on net income during 2003 and a $1 million impact in 2002.

Market Risk

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 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. This is described in Note 3.

Energy Contracts

SDG&E records transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. For open contracts not expected to result in physical delivery, changes in market value of the contracts are recorded in these accounts during the period the contracts are open, with an offsetting entry to a regulatory asset or liability. The majority of the 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 for the year ended December 31, 2002 due to an interest-rate swap as discussed in Note 3.

NOTE 9. PREFERRED STOCK

(Dollars in millions, except call price)	Call/Redemption Price	December 31, 2003	December 31, 2002
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, 950,000 and 1,000,000 shares outstanding December 31, 2003 and December 31, 2002, respectively	$ 25.00	$ 24*	$ 25

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

All series of SDG&E's preferred stock have cumulative preferences as to dividends. The $20 par value preferred stock has two votes per share on matters being voted upon by shareholders of SDG&E and a liquidation value at par, whereas the no-par-value preferred stock is nonvoting and has a liquidation value of $25 per share, plus any unpaid dividends. SDG&E is authorized to issue 10,000,000 shares of no-par-value preferred stock (both subject to and not subject to mandatory redemption). All series are callable at December 31, 2003. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share per year from 2004 to 2007; the remaining 750,000 shares must be redeemed in 2008. On January 15, 2004, SDG&E redeemed 50,000 shares at $25 per share.

NOTE 10. ELECTRIC INDUSTRY REGULATION

Background

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

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

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

Department of Water Resources

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

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

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

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

Power Procurement

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

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

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

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

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

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

The 550-megawatt combined-cycle Palomar power plant in Escondido, California, to be constructed by Sempra Energy Resources, an affiliate, for completion in 2006.

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

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

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

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

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

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

SONGS

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

FERC Actions

Refund Proceedings

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

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

Manipulation Investigation

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

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. FERC directed 43 entities, including SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. SDG&E and the FERC resolved the matter by SDG&E's paying $28 thousand into a FERC-established fund.

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

NOTE 11. OTHER REGULATORY MATTERS

Natural Gas Industry Restructuring

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

Natural Gas Market OIR

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

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

Cost of Service

The California Utilities have filed cost of service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs. SDG&E is requesting revenue increases of $76 million. The CPUC's Office of Ratepayer Advocates (ORA) filed its prepared testimony on the applications in August 2003, recommending numerous rate decreases that would reduce annual revenues by $41 million from their current level. The Utility Consumers' Action Network (UCAN), a consumer-advocacy group, has proposed rates for SDG&E that would reduce annual revenues by $88 million from their current level. Hearings concluded in November 2003. On December 19, 2003, settlements were filed with the CPUC that, if approved, would resolve most of the cost of service issues. The SDG&E settlement was signed by SDG&E, ORA and other parties, but not by UCAN, the City of Chula Vista and other parties. The CPUC adopted a schedule for briefing and commenting on the proposed settlements that concluded on February 19, 2004. The SDG&E settlement would reduce its electric rates by $19.6 million from 2003 rates and increase its natural gas rates by $1.8 million from 2003 rates. As part of the proposed settlement, SDG&E and the ORA would resolve their dispute concerning the allocation of the gain on sale of SDG&E's surplus property in Blythe, California, by increasing SDG&E's forecast of miscellaneous revenues by $1.3 million annually, thereby lowering its retail revenue requirement by that amount. The CPUC may accept one or both of the settlements or may adopt an outcome differing from both of the settlements. Resolution is likely in the second quarter of 2004.

On December 18, 2003, the CPUC issued a decision that creates memorandum accounts as of January 1, 2004, to record the difference between actual revenues and those that are later authorized in the

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

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

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

Performance-Based Regulation

To promote efficient operations and improved productivity and to move away from reasonableness reviews and disallowances, the CPUC adopted PBR for SDG&E effective in 1994. 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.

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

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

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

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

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

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

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

Incentive Awards Approved in 2003

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

Program	
Natural gas PBR Year 9	$ (1.4)
Natural gas PBR Year 8	6.7
Distribution PBR 2001	12.2
Distribution PBR 2002	6.0
Total	$ 23.5

Pending Incentive Awards

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

Program	
Natural gas PBR Year 10	$ 1.9
DSM/Energy Efficiency*	35.6
Total	$ 37.5

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

Cost of Capital

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

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

Border Price Investigation

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California-Arizona border between March 2000 and May 2001. If the investigation determines that the conduct of any party to the investigation contributed to the natural gas price spikes, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. Hearings are scheduled to begin in late March 2004 with a decision expected by late 2004. The company believes that the CPUC will find that SoCalGas acted in the best interests of its core customers.

Biennial Cost Allocation Proceeding

The BCAP determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the company and adjusts rates to reflect variances in customer demand as compared to the forecasts previously used in establishing transportation rates. SDG&E filed with the CPUC its 2005 BCAP application in September 2003, requesting updated transportation rates effective January 1, 2005. The most recent BCAP decision allocating the California Utilities non-commodity natural gas costs of service and revising their respective natural gas transportation rates and rate designs was issued in April 2000 and is still in effect. In November 2003, an Assigned Commissioner Ruling delayed the current BCAP applications until a decision is issued in the GIR implementation proceeding discussed above. As a result, SDG&E is required to amend its BCAP application 28 days after a decision in the GIR.

CPUC Investigation of Energy-Utility Holding Companies

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. Among the matters to be considered in the investigation are utility dividend policies and practices and obligations of the holding companies to provide financial support for utility operations under the agreements with the CPUC permitting the formation of the holding companies. In January 2002 the CPUC issued a decision to clarify under what circumstances, if any, a holding company would be required to provide financial support to its utility subsidiaries. The CPUC broadly determined that it would require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to cover their utility subsidiaries' capital requirements, as the IOUs have previously acknowledged in connection with the holding companies' formations. In January 2002 the CPUC ruled on jurisdictional issues, deciding that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed. The company's request for rehearing on the issues was denied by the CPUC and the company subsequently filed appeals in the California Court of Appeal. On November 26, 2003 the California Court of Appeal agreed to hear the company's appeal. Oral argument is set for March 5, 2004.

CPUC Investigation of Compliance with Affiliate Rules

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

FERC Standards of Conduct

On November 25, 2003, the FERC established standards of conduct governing the relationship between transmission providers and their energy affiliates. They broaden the definition of an energy affiliate. Under the standards, SDG&E is a transmission provider and SoCalGas is an energy affiliate of SDG&E. The standards require transmission providers to offer service to all customers on a non-discriminatory basis.

FERC Transmission Cost of Service

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

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

Recovery of Certain Disallowed Transmission Costs

In August 2002 the FERC issued Opinion No. 458, which effectively disallowed SDG&E's recovery of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink under the Participation Agreements and charges assessed to SDG&E under the ISO FERC tariff for transmission line losses and grid management charges related to energy schedules of Arizona Public Service Co. (APS) and the Imperial Irrigation District (IID), its Southwest Powerlink co-owners.

As a result, SDG&E is incurring unreimbursed costs of $4 million to $8 million per year. On November 17, 2003, SDG&E petitioned the United States Court of Appeals for review of these FERC orders and argued that the disallowed costs should be allowed for recovery through the Transmission Revenue Balancing Account Adjustment. On February 12, 2004, on the FERC's motion, the court remanded the case back to the FERC for further consideration, "based on the FERC's representation that it intends to act expeditiously on remand." The FERC has not yet issued further orders in this matter.

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

Southern California Fires

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

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

NOTE 12. COMMITMENTS AND CONTINGENCIES

Natural Gas Contracts

SDG&E buys natural gas under short-term contracts. Short-term purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. 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 2004 and

2023. SDG&E currently purchases natural gas on a spot basis to fill its long-term pipeline capacity and purchases additional spot market supplies delivered directly to California for its remaining requirements. SDG&E continues its ongoing assessment of its long-term pipeline capacity portfolio, including the release of a portion of this capacity to third parties.

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 2005, SoCalGas provides SDG&E eight billion cubic feet of storage capacity.

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

(Dollars in millions)	
2004	$ 20
2005	23
2006	16
2007	14
2008	14
Thereafter	142
Total minimum payments	$ 229

Total payments under natural gas contracts were $274 million in 2003, $205 million in 2002 and $457 million in 2001.

Purchased-Power Contracts

In January 2001, the California Assembly passed AB X1 to allow the DWR to purchase power under long-term contracts for the benefit of California consumers. In accordance with AB X1, SDG&E entered into an agreement with the DWR under which the DWR 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. In April 2003, the CPUC approved an operating agreement between the DWR and SDG&E that bestows upon SDG&E the role of a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions for the DWR contracts. For additional discussion of this matter see Note 10.

For 2004, SDG&E expects to receive 49 percent of its customer power requirement from DWR allocations. Of the remaining requirements, SONGS is expected to account for 21 percent, long-term contracts for 19 percent and spot market purchases for 11 percent. The contracts expire on various dates through 2025. Prior to January 1, 2001, the cost of these contracts was recovered by bidding them into the PX and receiving revenue from the PX for bids accepted. As of January 1, 2001, in compliance with a FERC order prohibiting sales to the PX, SDG&E no longer bids those contracts into the PX. Those contracts are now used to serve customers in compliance with a CPUC order. In addition, during

2002 SDG&E entered into contracts which will provide five percent of its 2004 total energy sales from renewable sources. These contracts expire on various dates through 2021.

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

(Dollars in millions)

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

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Excluding DWR-allocated contracts, total payments under the contracts were $396 million in 2003, $235 million in 2002 and $512 million in 2001.

Leases

SDG&E has operating leases on real and personal property expiring at various dates from 2004 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 3 percent to 6 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by SDG&E. SDG&E terminated its capital lease agreement for nuclear fuel in mid-2001 and now owns its nuclear fuel.

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

(Dollars in millions)

2004	$ 17
2005	16
2006	13
2007	11
2008	6
Thereafter	23
Total future rental commitments	$ 86

Rent expense totaled $28 million in 2003, $27 million in 2002 and $21 million in 2001.

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. 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 $5 million in 2003, $4 million in 2002 and $1 million in 2001. 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 expectation that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the latest three-year period include investigation and remediation of its manufactured-gas sites (three completed as of December 31, 2003 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).

Environmental liabilities are recorded when the company's liability is probable and the costs are reasonably estimable. In many cases, however, investigations are not yet at a stage where the company has been able to determine whether it is liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the cost or certain components thereof. Estimates of the company's liability are further subject to other uncertainties, such as the nature and extent of site contamination, evolving remediation standards and imprecise engineering evaluations. The accruals are reviewed periodically and, as investigations and remediation proceed, adjustments are made as necessary. At December 31, 2003, the company's accrued liability for environmental matters was $17.3 million, of which $5.8 million related to manufactured-gas sites, $10.5 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 $0.1 million to other hazardous waste sites. These accruals are expected to be paid ratably over the next two years.

Nuclear Insurance

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

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

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

Litigation

During 2003, the company recorded $11 million of after-tax charges against income for litigation costs and possible resolution of certain cases. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations. Except for the matters referred to below, neither the company nor its subsidiary is party to, nor is its property the subject of, any material pending legal proceedings other than routine litigation incidental to its businesses.

Antitrust Litigation

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

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

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

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 has filed an appeal in the 9th Circuit.

FERC Actions

Information regarding FERC actions related to the company is provided in Note 10 of the notes to Consolidated Financial Statements.

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 Department of Energy (DOE) will begin accepting spent nuclear fuel from SONGS. This delay by the DOE will lead to increased cost for spent fuel storage. This cost will be recovered through SONGS revenue unless the company is able to recover the increased cost from the federal government.

Electric Distribution System Conversion

Under a CPUC-mandated program, the cost of which is included in utility rates, and through franchise agreements with various cities, SDG&E is committed, in varying amounts, to converting overhead distribution facilities to underground. As of December 31, 2003, the aggregate unexpended amount of this commitment was $90 million. Capital expenditures for underground conversions were $28 million in 2003, $33 million in 2002 and $12 million in 2001.

Concentration Of Credit Risk

The company 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.

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

(Dollars in millions)	Quarters ended March 31	June 30	September 30	December 31
2003				
Operating revenues	$ 562	$ 520	$ 667	$ 562
Operating expenses	497	467	533	433
Operating income	$ 65	$ 53	$ 134	$ 129
Net income	$ 47	$ 42	$ 121	$ 130
Dividends on preferred stock	2	1	1	2
Earnings applicable to common shares	$ 45	$ 41	$ 120	$ 128
2002				
Operating revenues	$ 432	$ 414	$ 425	$ 454
Operating expenses	363	347	361	392
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

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

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

None.

ITEM 9A. 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.

Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company as of December 31, 2003 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 internal controls or in other factors that could significantly affect the internal controls subsequent to the date the company completed its evaluation..

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 2004 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	54	Chairman and Chief Executive Officer
Debra L. Reed	47	President and Chief Financial Officer
James P. Avery	47	Senior Vice President, Electric Transmission
Steven D. Davis	47	Senior Vice President, Customer Service and External Relations
Margot A. Kyd	50	Senior Vice President, Corporate Business Solutions
Roy M. Rawlings	59	Senior Vice President, Distribution Operations
William L. Reed	51	Senior Vice President, Regulatory Affairs
Lee M. Stewart	58	Senior Vice President, Gas Transmission
Terry M. Fleskes	47	Vice President and Controller

* As of December 31, 2003.

Except for Mr. Avery, each executive officer of San Diego Gas & Electric Company holds the same position at Southern California Gas Company and 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.

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 2004 annual meeting of shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The security ownership information required by Item 12 is incorporated by reference from "Share Ownership" in the Information Statement prepared for the May 2004 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information regarding principal accountant fees and services as required by Item 14 is incorporated by reference from "Proposal 3: Ratification of Independent Auditors" in the Proxy Statement prepared for the May 2004 annual meeting of shareholders.

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 88 of this report.

(b) Reports on Form 8-K

The following reports on Form 8-K were filed after September 30, 2003:

Current Report on Form 8-K filed November 6, 2003, filing as an exhibit Sempra Energy's press release of November 6, 2003, giving the financial results for the three months ended September 30, 2003.

Current Report on Form 8-K filed December 31, 2003, to update information on the August 25, 2003 CPUC decision regarding the allocation of profits from intermediate-term purchase power contracts. Updates when the Court of Appeals will have a decision on the petition submitted by an advocacy group for small consumers.

Current Report on Form 8-K filed February 24, 2004, filing as an exhibit Sempra Energy's press release of February 24, 2004, giving the financial results for the three months ended December 31, 2003.

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 23, 2004, appearing in the Annual Report on Form 10-K of San Diego Gas and Electric Company for the year ended December 31, 2003.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 24, 2004

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

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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 23, 2004~~
~~Principal Financial Officer:~~		
~~Debra L. Reed President and Chief Financial Officer~~	~~/s/ Debra L. Reed~~	~~February 23, 2004~~
~~Principal Accounting Officer:~~		
~~Terry M. Fleskes Vice President and Controller~~	~~/s/ Terry M. Fleskes~~	~~February 23, 2004~~
~~Directors:~~		
~~Edwin A. Guiles, Chairman~~	~~/s/ Edwin A. Guiles~~	~~February 23, 2004~~
~~Debra L. Reed, Director~~	~~/s/ Debra L. Reed~~	~~February 23, 2004~~
~~Frank H. Ault, Director~~		

~~/s/ Frank H. Ault~~
~~February 23, 2004~~

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. (2001 Form 10-K Exhibit 3.01)

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 Operating Agreement between San Diego Gas & Electric and the California Department of Water Resources dated April 17, 2003 (2003 Sempra Energy Form 10-K, Exhibit 10.06).

10.02 Servicing Agreement between San Diego Gas & Electric and the California Department of Water Resources dated December 19, 2002 (2003 Sempra Energy Form 10-K, Exhibit 10.07).

10.03 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).

10.04 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

10.05 2003 Sempra Energy Executive Incentive Plan B (2003 Sempra Energy Form 10-K, Exhibit 10.10).

10.06 2003 Executive Incentive Plan (June 30, 2003 Sempra Energy Form 10-Q Exhibit 10.1)

10.07 Amended 1998 Long-Term Incentive Plan (June 30, 2003 Sempra Energy Form 10-Q Exhibit 10.2)

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

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

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

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

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

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

10.14 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

10.15 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).

10.16 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).

10.17 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).

10.18 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).

10.19 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).

10.20 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).

10.21 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).

10.22 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).

10.23 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).

10.24 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).

10.25 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

10.26 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).

10.27 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.26 herein)(1994 SDG&E Form 10-K, Exhibit 10.56).

10.28 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 10.26 herein)(1994 SDG&E Form 10-K, Exhibit 10.57).

10.29 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 10.26 herein)(1996 Form 10-K, Exhibit 10.59).

10.30 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 10.26 herein)(1996 Form 10-K, Exhibit 10.60).

10.31 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 10.26 herein)(1999 Form 10-K, Exhibit 10.26).

10.32 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 10.26 herein)(1999 Form 10-K, Exhibit 10.27).

10.33 Seventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.26 herein)(2003 Sempra Energy Form 10-K, Exhibit 10.42).

10.34 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).

10.35 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 10.34 herein)(1996 Form 10-K, Exhibit 10.62).

10.36 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 10.34 herein)(1996 Form 10-K, Exhibit 10.63).

10.37 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 10.34 herein)(1999 Form 10-K, Exhibit 10.31).

10.38 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 10.34 herein)(1999 Form 10-K, Exhibit 10.32).

10.39 Fifth 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 10.34 herein)(2003 Sempra Energy Form 10-K, Exhibit 10.48).

10.40 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).

10.41 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

10.42 Master Services Contract (Intrastate Transmission Service), dated August 1, 2003(month to month) to August 1, 2005 between San Diego Gas & Electric Company and Southern California Gas Company. (1998 10-K, Exhibit 10.64)

10.43 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).

10.44 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).

10.45 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

10.46 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, 2003, 2002, 2001, 2000, and 1999.

Exhibit 21 - Subsidiaries

21.01 Schedule of Subsidiaries at December 31, 2003.

Exhibit 23 - Independent Auditors' Consent, page 86.

Exhibit 31 -- Section 302 Certifications

31.1 Statement of Registrant's Chief Executive Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

31.2 Statement of Registrant's Chief Financial Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

Exhibit 32 -- Section 906 Certifications

32.1 Statement of Registrant's Chief Executive Officer pursuant to 18 U.S.C. Sec. 1350.

32.2 Statement of Registrant's Chief Financial Officer pursuant to 18 U.S.C. Sec. 1350.

GLOSSARY

AB	California Assembly Bill
AB X1	A California Assembly bill authorizing the California Department of Water Resources to purchase energy for California consumers.
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
APS	Arizona Public Service Co.
BCAP	Biennial Cost Allocation Proceeding
Bcf	One Billion Cubic Feet (of natural gas)
Calpine	Calpine Corporation
CEC	California Energy Commission
CEMA	Catastrophic Event Memorandum Act
CPUC	California Public Utilities Commission
DOE	Department of Energy
DSM	Demand-Side Management
DWR	Department of Water Resources
Edison	Southern California Edison Company
EG	Electric Generation
EITF	Emerging Issues Task Force
El Paso	El Paso Energy Corp.
EMFs	Electric and Magnetic Fields
Enova	Enova Corporation
ERMG	Energy Risk Management
ERMOC	Energy Risk Management Oversight Committee
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position

GIR	Gas Industry Restructuring
ICIP	Incremental Cost Incentive Mechanism
IID	Imperial Irrigation District
Intertie	Pacific Intertie
IOUs	Investor-Owned Utilities
IRS	Internal Revenue Service
ISO	Independent System Operator
LIFO	Last in first out inventory costing method
LNG	Liquefied Natural Gas
MGP	Manufactured-Gas Plants
mmbtu	Million British Thermal Units (of natural gas)
Moody's	Moody's Investor Service, Inc.
MW	Megawatt
NRC	Nuclear Regulatory Commission
OIR	Order Instituting Ratemaking
ORA	Office of Ratepayers Advocates
PBR	Performance-Based Ratemaking/Regulation
PG&E	Pacific Gas and Electric Company
PGE	Portland General Electric Company
PIER	Public Interest Energy Research
PPA	Purchase Power Agreement
PRPs	Potentially Responsible Parties
PX	Power Exchange
QFs	Qualifying Facilities
RD&D	Research, Development and Demonstration
RFP	Requests For Proposals
ROE	Return on Equity
S&P	Standard & Poor's

SDG&E	San Diego Gas & Electric Company
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.
UCAN	Utility Consumers Action Network
VaR	Value at Risk

EXHIBIT 12.1

SAN DIEGO GAS & ELECTRIC COMPANY

COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

(Dollars in millions)

	1999	2000	2001	2002	2003
Fixed Charges and Preferred Stock Dividends:					
Interest	$ 131	$ 119	$ 96	$ 83	$ 78
Interest portion of annual rentals	5	3	3	4	3
Total fixed charges	136	122	99	87	81
Preferred stock dividends (1)	10	13	11	9	9
Combined fixed charges and preferred stock dividends for purpose of ratio	$ 146	$ 135	$ 110	$ 96	$ 90
Earnings:					
Pretax income from continuing operations	$ 325	$ 295	$ 324	$ 300	$ 488
Total fixed charges (from above)	136	122	99	87	81
Less: interest capitalized	1	3	1	1	1
Total earnings for purpose of ratio	$ 460	$ 414	$ 422	$ 386	$ 568
Ratio of earnings to combined fixed charges and preferred stock dividends	3.15	3.07	3.84	4.02	6.31

(1) In computing this ratio, "Preferred stock 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, 2003

Subsidiary	State of Incorporation
SDG&E Funding LLC	Delaware

EXHIBIT 31.1

CERTIFICATION

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 officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and we have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report, based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, 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 and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; 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 over financial reporting.

February 24, 2004

/S/ EDWIN A. GUILES
Edwin A. Guiles
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

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 officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and we have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report, based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, 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 and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; 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 over financial reporting.

February 24, 2004

/S/ DEBRA L. REED
Debra L. Reed
Chief Financial Officer

Exhibit 32.1

Statement of Chief Executive Officer

Pursuant to 18 U.S.C. Sec 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned Chief Executive Officer of San Diego Gas & Electric (the "Company") certifies that:

(i) the Annual Report on Form 10-K of the Company filed with the Securities and Exchange Commission for the year ended December 31, 2003 (the "Annual Report") fully complies with the requirements of Section 13(a) or Section 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2004

/S/ EDWIN A. GUILES

Edwin A. Guiles
Chief Executive Officer

Exhibit 32.2

Statement of Chief Financial Officer

Pursuant to 18 U.S.C. Sec 1350, as created by Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned Chief Financial Officer of San Diego Gas & Electric (the "Company") certifies that:

(i) the Annual Report on Form 10-K of the Company filed with the Securities and Exchange Commission for the year ended December 31, 2003 (the "Annual Report") fully complies with the requirements of Section 13(a) or Section 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 24, 2004

/S/ DEBRA L. REED

Debra L. Reed
Chief Financial Officer