UNITED STATES
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, 2005

[redacted]

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from [redacted] to [redacted]

Commission file number 1-3779

[redacted]

SAN DIEGO GAS & ELECTRIC COMPANY

[redacted]

(Exact name of registrant as specified in its charter)

California	95-1184800
[redacted]	[redacted]
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

8326 Century Park Court, San Diego, California 92123

[redacted]

(Address of principal executive offices)
(Zip Code)

(619) 696-2000

[redacted]

(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
[redacted]	

Preference Stock (Cumulative) Without Par Value (except $1.70 and $1.7625 Series)	American
Cumulative Preferred Stock, $20 Par Value (except 4.60% Series)	American

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

[redacted]

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [redacted] No X [redacted]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes [redacted] No X [redacted]

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X [redacted] No [redacted]

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 [redacted]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	[ ]	Accelerated filer	[ ]	Non-accelerated filer	[X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes		No	X

Exhibit Index on page 82. Glossary on page 89.

Aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2005 was $24.6 million.

Registrant's common stock outstanding as of January 31, 2006 was wholly owned by Enova Corporation.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Information Statement prepared for the May 2006 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, the California State

Legislature, the California Department of Water Resources, and the Federal Energy Regulatory Commission and other regulatory bodies in the United States; capital markets conditions, inflation rates, interest rates and exchange rates; energy and trading markets, including the timing and extent of changes in commodity prices; the availability of natural gas; weather conditions and conservation efforts; war and terrorist attacks; business, regulatory, environmental and legal decisions and requirements; the status of deregulation of retail natural gas and electricity delivery; the timing and success of business development efforts; the resolution of litigation; 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 AND RISK FACTORS

Description of Business

A description of San Diego Gas & Electric Company (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 Sempra Energy's website address is http://www.sempra.com. 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 California Public Utilities Commission (CPUC), which consists of five commissioners appointed by the Governor of California for staggered six-year terms, regulates SDG&E's rates (except electric transmission rates, which are regulated by the Federal Energy Regulatory Commission (FERC)) 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 (which may include reasonableness and prudency reviews) and affiliate relationships 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. Various proceedings involving the CPUC and relating to SDG&E's rates, costs, incentive mechanisms, performance-based regulation and compliance with affiliate and holding company rules 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 the company'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) for the California Utilities. Under PBR, regulators require future income potential to be tied to achieving or exceeding specific performance and operating income 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; energy efficiency rewards based on the effectiveness of the programs; and natural gas procurement rewards. Although SDG&E has received PBR rewards in the past, there can be no assurance that it will receive rewards in the future, or that they would be of comparable amounts. Additionally, if the company fails to achieve certain minimum performance levels established under the PBR mechanisms, it may be assessed financial disallowances or penalties which could negatively affect earnings and cash flows.

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

The company may be adversely affected 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 the company operates, could affect its ability to recover various costs through rates or adjustment mechanisms, or could require the company 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 (NRC) 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.

The California Utilities' future results of operations and financial condition may be materially adversely affected by the outcome of pending litigation against them.

The California energy crisis of 2000-2001 has generated numerous lawsuits, governmental investigations and regulatory proceedings involving many energy companies, including Sempra Energy and the California Utilities. In January 2006, Sempra Energy and the California Utilities reached agreement to settle several of these lawsuits including, subject to court and other approvals, the principal class action antitrust lawsuits in which they are defendants. The companies remain defendants in several additional lawsuits arising out of the energy crisis, including lawsuits commenced in the fourth quarter of 2005 by the California Attorney General. The company is also responding to an ongoing CPUC proceeding related to the increase in natural gas prices at the California-Arizona border in 2000-2001. Sempra Energy and the California Utilities have expended and continue to expend substantial amounts defending these lawsuits and in connection with related investigations and regulatory proceedings. Sempra Energy and the California Utilities have established reserves for the agreed and unresolved issues. However, given the uncertainties involved in resolving litigation, Sempra Energy's and the California Utilities' results of operations and financial condition may be materially adversely affected.

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.

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

The company's utility operations are the major source of liquidity. The company's ability to pay dividends on its preferred stock is largely dependent on the sufficiency of utility earnings and cash flows in excess of operational needs.

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

Like other major industrial facilities, the company's 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 or significant additional costs to the company, which could have a material adverse effect on the company'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 or property belonging to third parties, or personal injuries, which could lead to significant claims against the company. 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 the California Utilities with Sempra Energy and is currently investigating this relationship, as discussed further in Note 10 of the notes to Consolidated Financial Statements herein.

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. Further discussion is provided in Notes 9, 10 and 11 of the notes to Consolidated Financial Statements herein.

The 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, operate and maintain facilities for the transmission and distribution of electricity and/or natural gas in streets and other public places. Most of the franchises have indeterminate lives, except for the electric and natural gas franchises with the cities of Encinitas (2012), San Diego (2020), Coronado (2028) and Chula Vista (2035), and the natural gas franchises with the city of Escondido (2035) and the county of San Diego (2029).

Licenses and Permits

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

Other regulatory matters are described in Notes 9 and 10 of the notes to Consolidated Financial Statements herein.

NATURAL GAS UTILITY OPERATIONS

Resource Planning and Natural Gas Procurement and Transportation

The company is engaged in the purchase and distribution of natural gas. The company's resource planning, power 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 10 and 11 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, large commercial and industrial 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. The company continues to be obligated to purchase reliable supplies of natural gas to serve the requirements of core customers.

Natural Gas Procurement and Transportation

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

SDG&E has long-term natural gas transportation contracts with various interstate pipelines that expire on various dates between 2006 and 2023. SDG&E currently purchases natural gas on a spot basis from Canada, the Rocky Mountain area and the Southwestern U.S. 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 pipeline capacity portfolio, including the release of a portion of this capacity to third parties. In accordance with regulatory directives, SDG&E has reconfigured its pipeline capacity portfolio as of November 2005 to secure firm transportation rights from a diverse mix of U.S. and Canadian supply sources for its projected core customer natural gas requirements. All of SDG&E's natural gas is delivered through SoCalGas' pipelines under a long-term transportation agreement. In addition, under separate agreements expiring in March 2008, SoCalGas provides SDG&E up to nine billion cubic feet of storage capacity.

According to "Btu's Daily Gas Wire", the annual average spot price of natural gas at the California/Arizona border was $7.62 per million British thermal unit (mmbtu) in 2005 ($11.42 per mmbtu in December 2005), compared with $5.57 per mmbtu in 2004 and $5.13 per mmbtu in 2003. The company's weighted average cost (including transportation charges) per mmbtu of natural gas was $8.67 in 2005, $6.11 in 2004 and $5.14 in 2003.

Demand for Natural Gas

The company faces competition in the residential and commercial customer markets based on the customers' preferences for natural gas compared with other energy products. In the non-core industrial market, some customers are capable of using alternate fuels, which can affect the demand for natural gas. The company's ability to maintain its industrial market share is largely dependent on energy prices. The demand for natural gas by electric generators is influenced by a number of factors. In the short-term, natural gas use by electric generators 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 used to generate electricity will be influenced by additional factors such as the location of new power plant construction and the development of renewable resources. More generation capacity currently is being constructed outside Southern California than within the California Utilities' service area. This new generation will likely displace the output of older, less efficient local generation, reducing the use of natural gas for local electric generation.

Effective March 31, 1998, electric industry restructuring provided out-of-state producers the option to provide power to 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 the company's natural gas operations, future volumes of natural gas transported for electric generating plant customers may be significantly affected to the extent that regulatory changes divert electric generation from the company'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, development of renewable resources, development of new natural gas supply sources and general economic conditions can result in significant shifts in demand and market price. The company added 12,000 new customer meters in each of 2005 and 2004, representing growth rates of 1.5 percent in both years. The company expects that its growth rate for 2006 will approximate 2005's.

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

ELECTRIC UTILITY OPERATIONS

Customers

At December 31, 2005, the company had 1.3 million meters consisting of 1,188,000 residential, 141,000 commercial, 480 industrial, 1,990 street and highway lighting, and 6,700 direct access. The company's service area covers 4,100 square miles. The company added 20,000 new customer meters in 2005 and 22,000 in 2004, representing growth rates of 1.5% and 1.7%, respectively.

Resource Planning and Power Procurement

SDG&E's resource planning, power procurement and related regulatory matters are discussed below, in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 9, 10 and 11 of the notes 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, 2005, the supply of electric power available to SDG&E is as follows:

Supplier	Source	Expiration date	Megawatts (MW)
PURCHASED POWER CONTRACTS:			
DWR ** -allocated contracts:			
Williams Energy Marketing & Trading	Natural gas	2007 to 2010	1,906 *
Sunrise Power Co. LLC	Natural gas	2012	574
Other	Natural gas / wind	2006 to 2013	227
Total			2,707
Other contracts with Qualifying Facilities (QFs):			
Applied Energy Inc.	Cogeneration	2019	102

Yuma Cogeneration	Cogeneration	2024	50
Goal Line Limited Partnership	Cogeneration	2025	50
Other (16 contracts)	Cogeneration	2009 and thereafter	61
Total			263
Other contracts with renewable sources:			
Oasis Power Partners	Wind	2019	60
AES Delano	Bio-mass	2007	49
PPM Energy	Wind	2018	25
WTE / FPL	Wind	2019	17
Other (6 contracts)	Bio-gas	2007-2014	24
Total			175
Other long-term contracts:			
Portland General Electric (PGE)	Coal	2013	89
Total contracted			3,234
GENERATION:			
SONGS			430
Miramar			47
Total Generation			477
TOTAL CONTRACTED AND GENERATION			3,711

* Effective January 1, 2007, 1,200 megawatts were reallocated to Southern California Edison (Edison) by the CPUC, as described in Note 9 of the notes to Consolidated Financial Statements.
** Department of Water Resources

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 non-fuel 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 SONGS, which is located south of San Clemente, California. SONGS consists of three nuclear generating units. The cities of Riverside and Anaheim own a total of 5 percent of Units 2 and 3. Edison owns the remaining interests and is the operator of SONGS.

Unit 1 was removed from service in November 1992 when the CPUC issued a decision to permanently shut it down. Decommissioning of Unit 1 is now in progress and its spent nuclear fuel is being stored on site.

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 had fully recovered its SONGS capital investment through December 31, 2003.

Additional information concerning the SONGS units and nuclear decommissioning is provided below, in "Environmental Matters" herein, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 3, 9 and 11 of the notes to Consolidated Financial Statements herein.

Nuclear Fuel Supply

The nuclear fuel supply cycle includes materials and services (uranium oxide, conversion of uranium oxide to uranium hexafluoride, uranium enrichment services, and fabrication of fuel assemblies) performed by others under various contracts which extend through 2008. The availability and the cost of the various components of the nuclear-fuel cycle for SDG&E's nuclear facilities in subsequent years cannot be estimated at this time.

Spent fuel from SONGS is being stored on site in the independent spent fuel storage installation, where storage capacity is expected to be adequate through 2022, the expiration date of the units' 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 from SONGS. SDG&E pays the DOE 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.

Additional information concerning nuclear-fuel costs and the storage and movement of spent fuel is provided in Notes 9 and 11, respectively, 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 270 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 the FERC.

Transmission Arrangements

The Pacific 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 Pacific Intertie is 266 MW.

Power originating from sources utilizing the Pacific Intertie, as well as power from other sources, can be imported into SDG&E's system via the Edison-SDG&E interconnection at the SONGS switchyard. Five 230-kilovolt transmission lines into SDG&E's system from that interconnection comprise the "South of SONGS" path, which is normally rated at 2200 MW.

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 under certain system conditions.

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.

SDG&E is in the planning stages for the Sunrise Powerlink, a new 500-kilovolt transmission line between the existing Imperial Valley Substation and a new Central Substation to be located within the SDG&E system. The proposed rating of the Sunrise Powerlink is 1,000 MW or higher. The project is subject to CPUC approval and is estimated to cost at least $1 billion. The planned in-service date is June 2010.

Transmission Access

The National Energy Policy Act governs procedures for others' requests for transmission service. The FERC approved the California IOUs' transfer of operation and control of their transmission facilities to the Independent System Operator (ISO) in 1998. Additional information regarding the FERC, ISO and transmission issues is provided in Note 10 of the notes to Consolidated Financial Statements herein.

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, 9 and 10 of the notes to Consolidated Financial Statements herein.

ENVIRONMENTAL MATTERS

Discussions about environmental issues affecting the company are included in Note 11 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.

At December 31, 2005, the company had accrued its estimated remaining investigation and remediation liability related to hazardous waste sites, including numerous locations that had been manufactured-gas plants, of $7.2 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation costs of $10.3 million 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 childhood leukemia and the proximity of homes to certain power lines and equipment. 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 previously 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. The CPUC has recently reviewed the resultant policy in an Order Instituting Ratemaking and found no new scientific research to support a change to the existing policy, finding existing policy of prudent avoidance to be sufficient and reasonable.

Air and Water Quality

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. SDG&E's share of the cost is estimated to be $34 million, of which $16 million had been incurred at December 31, 2005. Rate recovery of 50% of the remaining costs is uncertain.

OTHER MATTERS

Research, Development and Demonstration (RD&D)

Effective January 2005, a surcharge was established by the CPUC for natural gas public interest RD&D. The natural gas public interest research program is administered by the CEC. For 2005, the funding level is subject to a statewide cap of $12 million. The statewide cap increases to $15 million in 2006. For 2005, SDG&E funding for the natural gas public purpose RD&D program was $1 million.

SDG&E continues to fund the California Public Interest Energy Research (PIER) Program for electric research. For 2005, SDG&E's funding level was $6 million for the PIER program.

Employees of Registrant

As of December 31, 2005, the company had 4,505 employees, compared to 4,405 at December 31, 2004.

Labor Relations

Certain employees at SDG&E are represented by the Local 465 International Brotherhood of Electrical Workers. The current contract is in effect through August 31, 2008.

ITEM 2. PROPERTIES

Electric Properties

SDG&E's interest in SONGS is described in "Electric Resources" herein. At December 31, 2005, 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 of California and in Arizona, and consist of 1,835 miles of transmission lines and 21,601 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

In 2005, SDG&E purchased a 45-MW electric generation facility located in San Diego, California. In 2006, SDG&E will purchase the 550-MW Palomar power plant, located in Escondido, California, which is being constructed by Sempra Generation.

Natural Gas Properties

At December 31, 2005, SDG&E's natural gas facilities, which are located in San Diego and Riverside counties of California, consisted of the Moreno and Rainbow compressor stations, 166 miles of high pressure transmission pipelines, 8,100 miles of high and low pressure distribution mains, and 6,197 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 warehouses, 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 11 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.

Sempra Energy and SDG&E are defendants in a lawsuit filed by the County of San Diego seeking civil penalties for alleged violations of environmental standards applicable to the abatement, handling and disposal of asbestos-containing materials during the demolition of a natural gas storage facility in 2001. In a federal criminal indictment, SDG&E and two employees have also been charged with having violated these standards and with conspiracy and making false statements to governmental authorities in connection with these matters. Sempra Energy and SDG&E believe that the maximum fines and penalties that could reasonably be assessed against them with respect to these matters would not exceed $750,000. The company believes that the claims and charges are without merit and is vigorously contesting them.

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 dividend declarations is included in the "Statements of Consolidated Changes in Shareholders' Equity" set forth in Item 8 of the 2005 Annual Report to Shareholders herein.

ITEM 6. SELECTED FINANCIAL DATA

(Dollars in millions, except per share amounts)	At December 31, or for the years then ended				
	2005	2004	2003	2002	2001
Income Statement Data:					
Operating revenues	$ 2,512	$ 2,274	$ 2,308	$ 1,725	$ 2,359
Operating income	$ 283	$ 256	$ 388	$ 256	$ 241
Dividends on preferred stock	$ 5	$ 5	$ 6	$ 6	$ 6
Earnings applicable to common shares	$ 262	$ 208	$ 334	$ 203	$ 177
Balance Sheet Data:					
Total assets	$ 7,492	$ 6,834	$ 6,461	$ 6,285	$ 6,542
Long-term debt	$ 1,455	$ 1,022	$ 1,087	$ 1,153	$ 1,229
Short-term debt (a)	$ 66	$ 66	$ 66	$ 66	$ 93
Preferred stock subject to mandatory redemption (b)	$ --	$ --	$ --	$ 25	$ 25
Shareholders' equity	$ 1,562	$ 1,376	$ 1,343	$ 1,223	$ 1,165

(a) Includes long-term debt due within one year.
(b) At December 31, 2005 and 2004, $16 million and $19 million, respectively, were included in Deferred Credits and Other Liabilities, and $3 million and $2 million, respectively, were included in Other Current Liabilities on the Consolidated Balance Sheets.

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 of the 2005 Annual Report includes management's discussion and analysis of operating results from 2003 through 2005, and provides information about the capital resources, liquidity and financial performance of San Diego Gas & Electric Company (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 Annual Report.

The company is an operating public utility engaged in the electric business, serving 3.4 million consumers, and in the natural gas business, serving 3.1 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 825,000 meters in San Diego County and transports electricity and natural gas for others. SDG&E's service territory encompasses 4,100 square miles. 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 2 of the notes to Consolidated Financial Statements. SDG&E is a substantially wholly owned indirect subsidiary of Sempra Energy. SDG&E and its sister utility, Southern California Gas Company (SoCalGas), which distributes natural gas throughout most of Southern California and a portion of central California, are collectively referred to herein as "the California Utilities."

RESULTS OF OPERATIONS

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

(Dollars in millions)

2005	$ 267
2004	$ 213
2003	$ 340
2002	$ 209
2001	$ 183

Comparison of Earnings

To assist the reader in understanding the trend of earnings, the following table summarizes the major unusual factors affecting net income and operating income in 2005, 2004 and 2003. The numbers in parentheses are the page numbers where each 2005 item is discussed therein.

	Net Income			Operating Income		
(Dollars in millions)	2005	2004	2003	2005	2004	2003
Reported amounts	$ 267	$ 213	$ 340	$ 283	$ 256	$ 388
Unusual items:						
Resolution of prior years' income tax issues (21)	(60)	(12)	(79)	(60)	(12)	(79)
Increase in California energy crisis litigation reserves (66)	28	11	11	28	11	11
South Bay charitable contribution deduction (21)	(23)	--	--	(21)	--	--
DSM[1] awards (62)	(22)	--	--	(21)	--	--
Other regulatory matters (66)	(23)	(21)	--	(20)	(15)	--
Power contract settlement	--	--	(65)	--	--	(65)
SONGS2 incentive pricing (ended 12/31/03)	--	--	(53)	--	--	(53)

	$ 167	$ 191	$ 154	$ 189	$ 240	$ 202

1 Demand side management (DSM)
2 San Onofre Nuclear Generating Station (SONGS)

The company is subject to federal, state and local governmental agencies. The primary regulatory agency is the California Public Utilities Commission (CPUC), which regulates utility rates and operations. The Federal Energy Regulatory Commission (FERC) regulates interstate transportation of natural gas and electricity and various related matters. The Nuclear Regulatory Commission regulates nuclear generating plants. Municipalities and other local authorities regulate the location of utility assets, including natural gas pipelines and electric lines.

Electric Revenue and Cost of Electric Fuel and Purchased Power. Electric revenues increased by $125 million (7%) to $1.8 billion in 2005, and the cost of electric fuel and purchased power increased by $48 million (8%) to $624 million in 2005. The increase in revenue was due to $41 million of higher revenues for recoverable expenses, which are fully offset in other operating expenses, a DSM award settlement in 2005 of $28 million and $23 million related to the 2005 Internal Revenue Service (IRS) decision relating to the sale of SDG&E's former South Bay power plant. In addition, revenues and costs increased $48 million due to higher purchased power costs.

Electric revenues decreased by $123 million (7%) to $1.7 billion in 2004 compared to 2003, and the cost of electric fuel and purchased power increased by $35 million (6%) to $576 million in 2004 compared to 2003. The decrease in revenues was due to the recognition of $116 million related to the approved settlement that allocated between SDG&E's customers and shareholders the profits from certain intermediate-term purchase power contracts in the third quarter of 2003, and higher 2003 earnings of $25 million from Performance-Based Regulation (PBR) awards. Performance awards are discussed in Note 10 of the notes to Consolidated Financial Statements. In addition, electric revenues and costs increased $35 million due to higher electric commodity costs and volumes.

Natural Gas Revenue and Cost of Natural Gas. Natural gas revenues increased by $113 million (19%) to $709 million in 2005, and the cost of natural gas increased by $109 million (31%) to $456 million in 2005. The increases in 2005 were due to higher natural gas prices, which are passed on to customers, offset by a small decrease in volume. In addition, natural gas revenues increased due to $7 million in DSM awards in 2005. The company's weighted average cost per million British thermal units (mmbtu) of natural gas was $8.67 in 2005, $6.11 in 2004 and $5.14 in 2003.

Although the current regulatory framework provides that 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, SDG&E's natural gas procurement 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. Further discussion is provided in Notes 1 and 10 of the notes to Consolidated Financial Statements.

Natural gas revenues increased by $89 million (18%) to $596 million in 2004 compared to 2003, and the cost of natural gas increased by $73 million (27%) to $347 million in 2004 compared to 2003. The increase in 2004 was primarily attributable to natural gas price increases.

The tables below summarize the electric and natural gas volumes and revenues by customer class for the years ended December 31, 2005, 2004 and 2003.

Electric Distribution and Transmission
(Volumes in millions of kWhs, dollars in millions)

	2005		2004		2003	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
Residential	7,075	$ 738	7,038	$ 692	6,702	$ 731
Commercial	6,674	654	6,592	644	6,263	674
Industrial	2,159	142	2,084	134	1,987	162
Direct access	3,213	114	3,441	105	3,322	87
Street and highway lighting	93	11	97	11	91	11
Off-system sales	--	--	--	--	8	--

	19,214	1,659	19,252	1,586	18,373	1,665
Balancing accounts and other		144		92		136
Total		$ 1,803		$ 1,678		$ 1,801

Although commodity costs associated with long-term contracts allocated to SDG&E from the Department of Water Resources (DWR) (and the revenues to recover those costs) are not included in the Statements of Consolidated Income, as discussed in Note 1 of the notes to Consolidated Financial Statements, the associated volumes and distribution revenues are included in the above table.

Natural Gas Sales, Transportation and Exchange
(Volumes in billion cubic feet, dollars in millions)

	Natural Gas Sales		Transportation and Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
2005:						
Residential	31	$ 381	--	$ --	31	$ 381
Commercial and industrial	17	174	4	5	21	179
Electric generation plants	1	3	59	39	60	42
	49	$ 558	63	$ 44	112	602
Balancing accounts and other						107
Total						$ 709
2004:						
Residential	33	$ 332	--	$ --	33	$ 332
Commercial and industrial	18	142	4	4	22	146
Electric generation plants	--	2	74	36	74	38
	51	$ 476	78	$ 40	129	516
Balancing accounts and other						80
Total						$ 596
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						51
Total						$ 507

Litigation Expenses. Litigation expenses were $52 million, $19 million and $17 million for 2005, 2004 and 2003, respectively. The increase in 2005 was primarily due to an increase in litigation reserves related to matters arising from the 2000 - 2001 California energy crisis. Note 11 of the notes to Consolidated Financial Statements provides additional information concerning this matter.

Other Operating Expenses. Other operating expenses were $603 million, $574 million and $611 million in 2005, 2004 and 2003, respectively. The increase in 2005 was due to $37 million of higher recoverable expenses, $34 million of favorable resolution of regulatory matters in 2004 and increases in various other operational costs, offset by the $42 million net effect related to the 2005 recovery of line losses and grid management charges arising from the favorable settlement with the Independent System Operator (ISO, an independent operator of California's wholesale transmission grid). The decrease in 2004 from 2003 was due primarily to the favorable resolution of regulatory matters.

Other Income, Net. Other income, net, as discussed further in Note 1 of the notes to Consolidated Financial Statements, consists primarily of interest income from short-term investments, income taxes on non-operating income, interest income/expense from regulatory balancing accounts and allowance for equity funds used during construction. Excluding the impact of income taxes on non-operating income, other income was $37 million, $36 million and $46 million in 2005, 2004 and 2003, respectively. The decrease in 2004 from 2003 was due to higher interest income in 2003 resulting from the favorable $37 million before-tax resolution of income-tax issues with the IRS, offset by a lesser amount of interest earned on income tax receivables during 2004.

Income Taxes. Income tax expense was $89 million for 2005 and $148 million for each of 2004 and 2003. The corresponding effective income tax rates were 25 percent, 41 percent and 30 percent. The decrease in 2005 expense was due to the lower effective tax rate. The decrease in the effective rate was due primarily to a $60 million favorable resolution of prior years' income tax issues in 2005, compared to $12 million in 2004. The higher effective income tax rate in 2004 compared to 2003 was due primarily to the comparatively low rate in 2003 resulting from the $57 million favorable resolution of income-tax issues. 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.

Net Income. SDG&E recorded net income of $267 million, $213 million and $340 million in 2005, 2004 and 2003, respectively. The increase in 2005 was due primarily to the regulatory resolution of the recovery of line losses and grid management charges arising from the favorable after-tax settlement of $23 million with the ISO (as discussed further in Note 10 of the notes to Consolidated Financial Statements), the recognition of DSM awards of $22 million after-tax, favorable resolution of income tax issues of $60 million, and the $23 million recovery of costs associated with the 2005 IRS decision relating to the sale of the South Bay power plant, offset by a $17 million increase in after-tax California energy crisis litigation expenses, the favorable after-tax impact of $21 million from the resolution of the 2004 Cost of Service proceeding, and $19 million from lower after-tax electric transmission and distribution margin and higher operational costs in 2005. In addition to the 2004 matters noted above, the decrease in 2004 from 2003 was primarily due to the favorable resolution of income tax issues in 2003, which positively affected 2003 earnings by $79 million, income of $65 million after-tax in 2003 related to the approved settlement of intermediate-term power purchase contracts that SDG&E had entered into during the early stages of California's electric utility industry restructuring; the 2003 Incremental Cost Incentive Pricing income (as discussed further in Note 9 of the notes to Consolidated Financial Statements) for SONGS ($53 million after-tax) and higher performance awards in 2003, offset by higher electric transmission and distribution margin in 2004.

CAPITAL RESOURCES AND LIQUIDITY

The company's utility operations generally are the major source of liquidity. In addition, working capital requirements can be met through the issuance of short-term and long-term debt. Cash requirements primarily consist of capital expenditures for utility plant.

At December 31, 2005, there was $236 million in unrestricted cash and $500 million in available unused, committed lines of credit. Management believes that these amounts and cash flows from operations and security issuances will be adequate to finance capital expenditures and meet liquidity requirements and other commitments. Forecasted capital expenditures for the next five years are discussed in "Future Capital Expenditures for Utility Plant." Management continues to regularly monitor the company's ability to finance the needs of its operating, investing and financing 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 $338 million, $435 million and $567 million for 2005, 2004 and 2003, respectively.

The 2005 change in net cash provided by operating activities was primarily due to a $246 million change in income taxes mainly due to an increase in income tax payments in 2005, offset by a $66 million decrease in other assets, a $62 million increase in other liabilities, a $57 million reduction of interest receivable and a $54 million increase in net income in 2005.

The decrease in cash flows from operations in 2004 compared to 2003 was primarily attributable to a lower net income in 2004.

The company made pension plan and other postretirement benefit plan contributions of $21 million and $7 million, respectively, during 2005, and $20 million and $8 million, respectively, during 2004.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $458 million, $289 million and $305 million for 2005, 2004 and 2003, respectively. The increase in cash used in investing activities in 2005 was due to a $50 million increase in capital expenditures in 2005 and a $122 million decrease in loans to affiliate in 2004. The decrease in cash used in investing activities in 2004 compared to 2003 was primarily due to greater than normal capital expenditures in 2003 as a result of the 2003 Southern California wildfires.

In December 2005, the company submitted its initial request to the CPUC for a proposed new transmission power line between the San Diego region and the Imperial Valley. The proposed line, called the Sunrise Powerlink, would be capable of providing electricity to 650,000 homes and is estimated to cost between $1 billion and $1.4 billion. The company expects to submit a proposed route and an alternative route to the CPUC in 2006.

Future Capital Expenditures for Utility Plant

Significant capital expenditures in 2006 are expected to include $1.2 billion for additions to the company's natural gas and electric distribution and generation systems. These expenditures are expected to be financed by cash flows from operations, asset sales and security issuances.

Over the next five years, the company expects to make capital expenditures of $4 billion at a rate ranging from $500 million to $1.2 billion per year.

Construction programs are periodically reviewed and revised by the company in response to changes in regulation, economic conditions, competition, customer growth, inflation, customer rates, the cost of capital and environmental requirements, as discussed in Note 11 of the notes to Consolidated Financial Statements.

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

The amounts and timing of capital expenditures are subject to approvals by the CPUC, the FERC and other regulatory bodies.

The possible SDG&E' involvement with completion of the Otay Mesa power plant is discussed in Note 9 of the notes to Consolidated Financial Statements.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash provided by (used in) financing activities totaled $347 million, $(285) million and $(273) million for 2005, 2004 and 2003, respectively.

The 2005 increase in cash provided by financing activities was due to the $500 million issuances of first mortgage bonds in 2005 and a $130 million decrease in common dividends paid in 2005. The company issued $251 million of first mortgage bonds in 2004 and applied the proceeds to refund an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a shorter maturity in the same year.

Long-Term and Short-Term Debt

In May 2005, the company publicly offered and sold $250 million of 5.35% first mortgage bonds, maturing in 2035. In November 2005, the company publicly offered and sold $250 million of 5.30% first mortgage bonds, maturing in 2015.

Payments on long-term debt in 2005 were $66 million related to its rate-reduction bonds.

In June 2004, the company issued $251 million of first mortgage bonds and applied the proceeds in July to refund an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a shorter maturity. The bonds secure the repayment of tax-exempt industrial development bonds of an identical amount, maturity and interest rate issued by the City of Chula Vista, the proceeds of which were loaned to the company and which are repaid with payments on the first mortgage bonds. The bonds were initially issued as auction-rate securities, but the company entered into floating-for-fixed interest-rate swap agreements that effectively changed the bonds' interest rates to fixed rates in September 2004. The swaps are set to expire in 2009.

Payments on long-term debt in 2004 included $251 million of SDG&E's first mortgage bonds and $66 million of rate-reduction bonds.

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

Note 2 of the notes to Consolidated Financial Statements provide information concerning lines of credit and further discussion of debt activity.

Dividends

Common dividends paid to Sempra Energy were $75 million in 2005, compared to $205 million in 2004 and $200 million in 2003.

The payment and amount of future dividends 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, 2005, no amounts were available from SDG&E.

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, 2005 was $3 billion. The debt-to-capitalization ratio was 47 percent at December 31, 2005.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2005. Additional information concerning commitments is provided above and in Notes 2, 5, 8 and 11 of the notes to Consolidated Financial Statements.

(Dollars in millions)	2006	2007 and 2008	2009 and 2010	Thereafter	Total
Long-term debt	$ 66	$ 66	$ --	$ 1,389	$ 1,521
Interest on debt (1)	78	145	152	1,687	2,062
Operating leases	19	29	17	19	84
Litigation reserve	25	50	--	--	75
Purchased-power contracts	247	536	565	2,627	3,975
Natural gas contracts	22	28	20	112	182
Preferred stock subject to mandatory redemption	3	16	--	--	19
Construction commitments	16	24	7	20	67
SONGS decommissioning	14	11	--	314	339
Other asset retirement obligations	4	9	5	105	123
Pension and postretirement benefit obligations (2)	41	106	89	257	493
Environmental commitments	9	9	--	--	18
Totals	$ 544	$ 1,029	$ 855	$ 6,530	$ 8,958

(1) Based on forward rates in effect at December 31, 2005.
(2) Amounts are after reduction for the Medicare Part D subsidy and only include expected payments to the plans for the next 10 years.
The table excludes contracts between affiliates, intercompany debt, individual contracts that have annual cash requirements less than $1 million and employment contracts.

Credit Ratings

Credit ratings of the company remained at investment grade levels in 2005. As of January 31, 2006, company credit ratings were still as follows:

	Standard & Poor's	Moody's Investor Services, Inc.	Fitch
Secured debt	A+	A1	AA
Unsecured debt	A-	A2	AA-
Preferred stock	BBB+	Baa1	A+
Commercial paper	A-1	P-1	F1+

As of January 31, 2006, 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. Performance will also depend on the successful completion of construction programs, which are discussed in various places in this report. These factors are discussed in Notes 9 and 10 of the notes to Consolidated Financial Statements. '

Litigation

Note 11 of the notes to Consolidated Financial Statements describes litigation (primarily cases arising from the California energy crisis), the ultimate resolution of which could have a material adverse effect on future performance.

Industry Developments

Notes 9 and 10 of the notes to Consolidated Financial Statements describe electric and natural gas restructuring and rates, and other pending proceedings and investigations.

Market Risk

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

The company has adopted policies governing its market risk management and trading activities of all affiliates. Assisted by the company's Risk Management Department (RMD), the company's Risk Management Committee (RMC) consisting of senior officers, establishes policy for and oversees company-wide energy risk management activities and monitors the results of trading and other activities to ensure compliance with the company's stated energy risk management policies and applicable regulatory requirements. The RMD receives daily information detailing positions regarding market positions that create credit, liquidity and market risk and monitors energy price risk management and measures and reports the market and credit risk associated with these positions to the RMC.

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 RMD for the company. Historical and implied volatilities and correlations between instruments and positions are used in the calculation. The company uses energy and natural gas derivatives to manage natural gas and energy price risk associated with servicing load requirements. The use of energy and natural gas derivatives is in compliance with risk management and trading activity plans that have been filed and approved by the CPUC. Any costs or gains/losses associated with the use of energy and natural gas derivatives, which use is in compliance with CPUC approved plans, are considered to be commodity costs that are passed on to customers in a substantially concurrent basis.

Revenue recognition is discussed in Note 1 and the additional market risk information regarding derivative instruments is discussed in Note 7 of the notes to Consolidated Financial Statements.

The following discussion of the company's primary market risk exposures as of December 31, 2005 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 the costs of electric procurement and natural gas purchases and sales. 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 Note 10 of the notes to Consolidated Financial Statements. If commodity prices were to rise too rapidly, it is likely that volumes would decline. This would increase the per-unit fixed costs, which could lead to further volume declines. The company manages its risk within the parameters of its market risk management framework. As of December 31, 2005, the company's VaR was not material and the procurement activities are in compliance with the procurement plans filed with and approved by the CPUC.

Interest Rate Risk

The company is exposed to fluctuations in interest rates primarily as a result of its short-term and long-term debt. The company historically has funded operations through long-term debt issues at fixed rates of interest recovered in utility rates. Some more-recent debt offerings have been issued with floating rates. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures.

At December 31, 2005, the company had $1.5 billion of fixed-rate debt and no 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, 2005, the company's fixed-rate debt had a one-year VaR of $171 million.

At December 31, 2005, the notional amount of interest-rate swap transactions totaled $251 million. Note 2 of the notes to Consolidated Financial Statements provides further information regarding interest-rate swap transactions.

In addition, the company is subject to the effect of interest-rate fluctuations on the assets of its pension plans, other postretirement plans and the nuclear decommissioning trust. However the effects of these fluctuations are expected to be passed on to customers.

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 policies governing the management of credit risk. Credit risk management is performed by the company's credit department and overseen by the company's RMC. Using rigorous models, the RMD and the company calculate current and potential credit risk to counterparties on a daily basis and monitor actual balances in comparison to approved limits. The company avoids concentration of counterparties whenever possible, and management believes its credit policies associated with 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 believes that adequate reserves have been provided for counterparty nonperformance.

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.

As noted above under "Interest Rate Risk," the company periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. The company would be exposed to interest-rate fluctuations on the underlying debt should counterparties to the agreement not perform.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES 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 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) 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 11 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 provides for income taxes. Details of the company's issues in this area are discussed in Note 4 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," SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities,"* and *Emerging Issues Task Force (EITF) Issue 02-3, "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities,"* 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 calculation of fair or realizable values.
>
> The probable costs to be incurred in the resolution of litigation.
>
> The collectibility of receivables, regulatory assets, deferred tax assets and other assets.
>
> The resolution of various income tax issues between the company and the various taxing authorities.

Differences between estimates and actual amounts have had significant impacts in the past and are likely to have significant impacts 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 credit-worthiness 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 credit-worthiness of the other parties and other factors. The anticipated resolution of income tax issues considers past resolutions of the same or similar issue, the status of any income tax examination in progress and positions taken by taxing authorities with other taxpayers with similar issues. 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 "Overview" and "Results of Operations."

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had a significant effect on the company's financial statements are SFAS 143 and Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47. They are described below.

SFAS 143, *"Accounting for Asset Retirement Obligations" and FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143":* 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. Issued in March 2005, FIN 47 clarifies that the term conditional asset-retirement obligation as used in SFAS 143 refers to a legal obligation to perform an asset-retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. FIN 47 requires companies to recognize a liability for the fair value of a conditional asset-retirement obligation if the fair value of the obligation can be reasonably estimated. FIN 47 is effective for the company's 2005 annual report.

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of company management, including the principal executive officer and principal financial officer, the company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control -- Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the company's evaluation under the framework in *Internal Control -- Integrated Framework*, management concluded that the company's internal control over financial reporting was effective as of December 31, 2005. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005 has been audited by Deloitte & Touche LLP, as stated in its report, which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2005 and 2004, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2005. 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 the standards of the Public Company Accounting Oversight Board (United States). 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 the Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, 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 Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143,* effective December 31, 2005.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 21, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that San Diego Gas & Electric and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2005 of the Company and our report dated February 21, 2006 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of a new accounting standard.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 21, 2006

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

	Years ended December 31,		
	2005	2004	2003
Operating revenues			
Electric	$ 1,803	$ 1,678	$ 1,801
Natural gas	709	596	507
Total operating revenues	2,512	2,274	2,308
Operating expenses			
Cost of electric fuel and purchased power	624	576	541
Cost of natural gas	456	347	274
Other operating expenses	603	574	611
Depreciation and amortization	264	259	242
Income taxes	110	137	127
Franchise fees and other taxes	119	113	114
Litigation expense	52	19	17
Gain on sale of assets	(1)	(1)	(9)
Impairment losses (adjustments)	2	(6)	3
Total operating expenses	2,229	2,018	1,920

Operating income	283	256	388
Other income, net (Note 1)	58	25	25
Interest charges			
Long-term debt	65	61	67
Other	12	10	11
Allowance for borrowed funds used during construction	(3)	(3)	(5)
Total	74	68	73
Net income	267	213	340
Preferred dividend requirements	5	5	6
Earnings applicable to common shares	$ 262	$ 208	$ 334

See notes to Consolidated Financial Statements.

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

	December 31, 2005	December 31, 2004
ASSETS		
Utility plant, at original cost	$ 6,927	$ 6,345
Accumulated depreciation and amortization	(1,956)	(1,821)
Utility plant, net	4,971	4,524
Nuclear decommissioning trusts	638	612
Current assets:		
Cash and cash equivalents	236	9
Accounts receivable - trade	188	185
Accounts receivable - other	83	30
Interest receivable	17	55
Due from unconsolidated affiliates	32	30
Deferred income taxes	7	--
Regulatory assets arising from fixed-price contracts and other derivatives	76	55
Other regulatory assets	91	77
Inventories	78	88

Other	39	31
Total current assets	847	560
Other assets:		
Deferred taxes recoverable in rates	294	278
Regulatory assets arising from fixed-price contracts and other derivatives	398	448
Other regulatory assets	276	341
Sundry	68	71
Total other assets	1,036	1,138
Total assets	$ 7,492	$ 6,834

See notes to Consolidated Financial Statements.

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

	December 31, 2005	December 31, 2004
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock (255 million shares authorized; 117 million shares outstanding)	$ 938	$ 938
Retained earnings	559	372
Accumulated other comprehensive income (loss)	(14)	(13)
Total common equity	1,483	1,297
Preferred stock not subject to mandatory redemption	79	79
Total shareholders' equity	1,562	1,376
Long-term debt	1,455	1,022
Total capitalization	3,017	2,398
Current liabilities:		
Accounts payable	243	200
Due to unconsolidated affiliates	441	15
Income taxes payable	6	225
Deferred income taxes	--	15
Regulatory balancing accounts, net	179	331
Fixed-price contracts and other derivatives	76	55

Customer deposits	52	45
Current portion of long-term debt	66	66
Other	282	256
Total current liabilities	1,345	1,208
Deferred credits and other liabilities:		
Due to unconsolidated affiliate	--	267
Customer advances for construction	39	45
Deferred income taxes	591	522
Deferred investment tax credits	34	37
Regulatory liabilities arising from removal obligations	1,216	1,246
Asset retirement obligations	444	318
Fixed-price contracts and other derivatives	398	448
Mandatorily redeemable preferred securities	16	19
Deferred credits and other	392	326
Total deferred credits and other liabilities	3,130	3,228
Commitments and contingencies (Note 11)		
Total liabilities and shareholders' equity	$ 7,492	$ 6,834

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,		
	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 267	$ 213	$ 340
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	264	259	242
Deferred income taxes and investment tax credits	37	--	(29)
Non-cash rate reduction bond expense	68	75	68
Other	(3)	(7)	(6)
Changes in other assets	13	(53)	(3)
Changes in other liabilities	37	(25)	(7)
Changes in working capital components:			
Accounts receivable	(56)	(24)	(9)

Interest receivable	39	(18)	(37)
Due to/from affiliates, net	(1)	13	2
Inventories	10	(27)	(14)
Other current assets	(16)	(1)	(23)
Income taxes	(231)	15	8
Accounts payable	28	6	34
Regulatory balancing accounts	(152)	(15)	(56)
Other current liabilities	34	24	57
Net cash provided by operating activities	338	435	567
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(464)	(414)	(444)
Purchases of nuclear decommissioning and other trusts	(230)	(244)	(271)
Proceeds from sales by nuclear decommissioning and other trusts	234	247	277
Net proceeds from sale of assets	1	--	4
Decrease in loans to affiliate, net	1	122	129
Net cash used in investing activities	(458)	(289)	(305)
CASH FLOWS FROM FINANCING ACTIVITIES			
Common dividends paid	(75)	(205)	(200)
Preferred dividends paid	(5)	(5)	(6)
Payments on long-term debt	(66)	(317)	(66)
Issuances of long-term debt	500	251	--
Redemption of preferred stock	(3)	(3)	(1)
Other	(4)	(6)	--
Net cash provided by (used in) financing activities	347	(285)	(273)
Increase (decrease) in cash and cash equivalents	227	(139)	(11)
Cash and cash equivalents, January 1	9	148	159
Cash and cash equivalents, December 31	$ 236	$ 9	$ 148

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,		
	2005	2004	2003

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Interest payments, net of amounts capitalized	$ 66	$ 63	$ 68
Income tax payments, net of refunds	$ 291	$ 129	$ 167

See notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2005, 2004 and 2003
(Dollars in millions)

	Comprehensive Income	Preferred Stock Not Subject to Mandatory Redemption	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
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 stock 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
Net income	$ 213			213		213
Other comprehensive income adjustment - pension	30				30	30
Comprehensive income	$ 243					
Preferred stock dividends declared				(5)		(5)
Common stock dividends declared				(205)		(205)
Balance at December 31, 2004		79	938	372	(13)	1,376
Net income	$ 267			267		267
Other comprehensive income adjustment - pension	(1)				(1)	(1)

Comprehensive income	$ 266					
Preferred stock dividends declared				(5)		(5)
Common stock dividends declared				(75)		(75)
Balance at December 31, 2005		$ 79	$ 938	$ 559	$ (14)	$ 1,562

See notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

Principles of Consolidation

The Consolidated Financial Statements include the accounts of San Diego Gas & Electric Company (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. In addition, in connection with charges related to litigation, the significant instances of which are discussed in Note 11, Sempra Energy management determines the allocation of the charges among its business units, including the company, based on the extent of their involvement with the subject of the litigation.

Use of Estimates in the Preparation of the Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) 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. Although management believes the estimates and assumptions are reasonable, 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 GAAP 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. To the extent that recovery is no longer probable as a result of changes in regulation or the utility's competitive position, the related regulatory assets would be written off. In addition, SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires that a loss be recognized whenever a regulator excludes all or part of utility plant or regulatory assets from ratebase. Regulatory liabilities represent reductions in future rates for amounts due to customers. Information concerning regulatory assets and liabilities is provided below in "Revenues," "Regulatory Balancing Accounts" and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The amounts included in regulatory balancing accounts at December 31, 2005, represent net payables (payables net of receivables) that are returned to customers by reducing future rates.

Except for certain costs subject to balancing account treatment, fluctuations in most operating and maintenance accounts affect utility earnings. Balancing accounts provide a mechanism for charging utility customers the amount actually incurred for certain costs, primarily commodity costs. The CPUC has also approved balancing account treatment for variances between forecast and actual for SDG&E's volumes and commodity costs, eliminating the impact on earnings from any throughput and revenue variances from adopted forecast levels. Additional information on regulatory matters is included in Notes 9 and 10.

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)	2005	2004
Fixed-price contracts and other derivatives	$ 473	$ 500
Recapture of temporary rate reduction*	116	183
Deferred taxes recoverable in rates	294	278
Unamortized loss on retirement of debt, net	42	46
Employee benefit costs	174	160
Removal obligations**	(1,216)	(1,246)
Other	36	29
Total	$ (81)	$ (50)

* In connection with electric industry restructuring, which is described in Note 9, SDG&E temporarily reduced rates to its small-usage customers. That reduction is being recovered in rates through 2007.
** This is related to SFAS 143, *Accounting for Asset Retirement Obligations,* which is discussed below in "New Accounting Standards."

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

(Dollars in millions)	2005	2004
Current regulatory assets	$ 167	$ 132
Noncurrent regulatory assets	968	1,067
Current regulatory liabilities*	--	(3)
Noncurrent regulatory liabilities	(1,216)	(1,246)
Total	$ (81)	$ (50)

* 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.

Non-cash Investing and Financing Activities

SDG&E added utility plant of $150 million and $267 million in 2005 and 2004, respectively, related to the Palomar power plant (discussed in Note 2), which will not be paid until 2006. In 2003 the company received $1 million of assets from Sempra Energy and assumed related liabilities of $6 million.

Collection Allowances

The allowance for doubtful accounts was $2 million at each of December 31, 2005, 2004 and 2003. The company recorded provisions for doubtful accounts of $3 million, $3 million and $1 million in 2005, 2004 and 2003, respectively.

Inventories

At December 31, 2005, inventory shown on the Consolidated Balance Sheets included natural gas of $30 million, and materials and supplies of $48 million. The corresponding balances at December 31, 2004 were $50 million and $38 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.

Income Taxes

Income tax expense includes current and deferred income taxes from operations during the year. In accordance with SFAS 109, *Accounting for Income Taxes*, the company records deferred income taxes for temporary differences between the book and tax bases of assets and liabilities. Investment tax credits from prior years are being amortized to income over the estimated service lives of the properties. Other credits, mainly low-income housing tax credits, are recognized in income as earned. The company follows certain provisions of SFAS 109 that permit regulated enterprises to recognize regulatory assets or liabilities to offset deferred tax liabilities and assets, respectively, if it is probable that such amounts will be recovered from, or returned to, customers.

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 certain expenditures incurred during a major maintenance outage of a generating plant. Maintenance costs are expensed as incurred. 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)	2005	2004	2005	2004	2003
Natural gas operations	$ 1.1	$ 1.0	3.42 %	3.42 %	3.63 %
Electric distribution	3.5	3.4	4.13 %	4.11 %	4.70 %
Electric transmission	1.1	1.0	3.05 %	3.06 %	3.09 %
Other electric	0.6	0.6	9.75 %	11.33 %	9.53 %
Construction work in progress	0.6	0.3	NA	NA	NA
Total	$ 6.9	$ 6.3			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $0.4 billion and $1.6 billion, respectively, at December 31, 2005, and were $0.4 billion and $1.4 billion, respectively, at December 31, 2004. Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. The discussion of SFAS 143 under "New Accounting Standards" describes a change in the presentation of accumulated depreciation.

AFUDC, which represents the cost of debt and equity funds used to finance the construction of utility plant, is added to the cost of utility plant. Although it is not a current source of cash, AFUDC increases income and is recorded partly as an offset to interest charges and partly as a component of Other Income, Net in the Statements of Consolidated Income. AFUDC amounted to $12 million, $12 million and $17 million for 2005, 2004 and 2003, respectively.

Nuclear Decommissioning Liability

At December 31, 2005 and 2004, the company had asset retirement obligations of $339 million and $328 million, respectively, and related regulatory liabilities of $346 million and $333 million, respectively, related to nuclear decommissioning, in accordance with SFAS 143. Information about San Onofre Nuclear Generating Station (SONGS) decommissioning costs is included below in "New Accounting Standards."

Legal Fees

Legal fees that are associated with a past event for which a contingent liability has been recorded are accrued when it is probable that fees also 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, which consists of all these changes other than net income as shown on the Statements of Consolidated Income, are shown in the Statements of Consolidated Changes in Shareholders' Equity. At December 31, 2005, Accumulated Other Comprehensive Income consisted entirely of minimum pension liability adjustments, net of related income tax.

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 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. Commodity costs associated with long-term contracts allocated to SDG&E from the DWR also are not included in the Statements of Consolidated Income, since the DWR retains legal and financial responsibility for these contracts. Note 9 includes 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.

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

Transactions with Affiliates

On a daily basis, SDG&E and SoCalGas share numerous functions with each other and they also receive various services from and provide various services to Sempra Energy.

At December 31, 2005 and 2004, SDG&E had $32 million and $30 million, respectively, due from affiliates. These amounts are included in current assets as Due from Unconsolidated Affiliates.

Additionally, at December 31, 2005, SDG&E had $441 million due to affiliates, including $20 million to Sempra Energy and $417 million related to the Palomar project, which is included in current liabilities as Due to Unconsolidated Affiliates. At December 31, 2004, SDG&E had $15 million due to Sempra Energy, which is included in current liabilities and $267 million related to the Palomar project, which is included in noncurrent liabilities. These amounts are reported as Due to Unconsolidated Affiliates.

Other Income, Net

Other Income, Net consists of the following:

	Years ended December 31,		
(Dollars in millions)	2005	2004	2003

Interest income	$ 23	$ 25	$ 42
Regulatory interest, net	(3)	(6)	(5)
Allowance for equity funds used during construction	9	9	12
Income taxes on non-operating income	21	(11)	(21)
Sundry, net	8	8	(3)
Total	$ 58	$ 25	$ 25

New Accounting Standards

SFAS 123 (revised 2004), "Share-Based Payment" (SFAS 123R): In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS 123R, a revision of SFAS 123, *Accounting for Stock-Based Compensation* (SFAS 123), which establishes the accounting for transactions in which an entity exchanges its equity instruments for goods or services received. This statement requires companies to measure and record the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. Sempra Energy expects to adopt the provisions of SFAS 123R using a modified prospective application. The modified prospective method requires companies to recognize compensation cost for unvested awards that are outstanding on the effective date based on the fair value that the company had originally estimated for purposes of preparing its SFAS 123 pro forma disclosures. For all new awards that are granted or modified after the effective date, a company would use SFAS 123R's measurement model. The effect of adopting FAS 123R has not been determined. The effective date of this statement is January 1, 2006 for Sempra Energy.

SFAS 143, "Accounting for Asset Retirement Obligations" and FASB Interpretation No (FIN) 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS 143": Beginning in 2003, SFAS 143 requires entities to record the present value of liabilities for future costs expected to be incurred when assets are retired from service, if the retirement process is legally required. It requires recording of the estimated retirement cost over the life of the related asset by depreciating the present value of the obligation (measured at the time of the asset's acquisition) and accreting the discount until the liability is settled. 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. On January 1, 2003, the company recorded additional asset retirement obligations of $10 million associated with the future retirement of a former power plant.

In March 2005, the FASB issued FIN 47, *"Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS 143."* The interpretation clarifies that the term "conditional asset-retirement obligation" as used in SFAS 143, refers to a legal obligation to perform an asset-retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. FIN 47 requires companies to recognize a liability for the fair value of a conditional asset-retirement obligation if the fair value of the obligation can be reasonably estimated.

The adoption of FIN 47 on December 31, 2005 resulted in the recording of an addition to utility plant of $32 million and accumulated depreciation of $13 million related to the increase to utility plant, for a net increase of $19 million. In addition, the company recorded a corresponding retirement obligation liability of $116 million (which includes accretion of that discounted value to December 31, 2005) and a regulatory liability of $164 million to reflect that the company has collected the funds from customers more quickly than FIN 47 would accrete the retirement liability and depreciate the asset.

The adoption of SFAS 143 required the reclassification of estimated removal costs collected in rates, which had historically been recorded in accumulated depreciation, to a regulatory liability. At December 31, 2005 and 2004, these costs were $724 million and $913 million, respectively. The change in the balance is due to the implementation of FIN 47, which required the reclassification of disposal costs that previously have been included in the company's estimated cost of removal obligations to a regulatory liability and to Asset Retirement Obligations.

In accordance with FIN 47, the company has determined that the amount of asbestos-containing materials could not be determined and, therefore, no liability has been recognized for the related removal obligations. Since most, if not all, of the cost of removing such materials would be expected to be recovered in rates, the effect of not recognizing these liabilities is not material to the company's financial condition or results of operations. A liability for the obligations will be recorded in the period in which sufficient information is available to reasonably estimate the removal cost.

Had FIN 47 been in effect on December 31, 2004, the asset retirement obligation liability would have been $109 million as of that date.

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

Implementation of SFAS 143 and FIN 47 had no significant effect on results of operations and is not expected to have a significant effect in the future.

The changes in the asset retirement obligations for the years ended December 31, 2005 and 2004 are as follows (dollars in millions):

	2005	2004
Balance as of January 1	$ 339*	$ 326*
Adoption of FIN 47	116	--
Accretion expense	23	23
Payments	(15)	(10)
Balance as of December 31	$ 463*	$ 339*

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

SFAS 154, "Accounting Changes and Error Corrections, a replacement of Accounting Principles Board Opinion (APBO) 20 and FASB Statement No. 3:" This statement applies to all voluntary changes in accounting principles and to changes required by an accounting pronouncement in instances where the pronouncement does not include specific transition provisions. APBO 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 requires retrospective application to prior periods' financial statements of changes in accounting principle**,** unless it is impracticable to do so. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

FIN 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin (ARB) No. 51": FIN 46, as revised by FIN 46R, requires an enterprise to consolidate a variable interest entity (VIE), as defined in FIN 46, if the company is the primary beneficiary of a VIE's activities.

Contracts under which SDG&E acquires power from generation facilities otherwise unrelated to SDG&E could result in a requirement for SDG&E to consolidate the entity that owns the facility. In accordance with FIN 46, SDG&E is continuing the process of determining whether it has any such situations and, if so, gathering the information that would be needed to perform the consolidation. The effects of this, if any, are not expected to significantly affect the financial position of SDG&E and there would be no effect on results of operations or liquidity.

NOTE 2. DEBT AND CREDIT FACILITIES

Committed Lines of Credit

SDG&E and its affiliate, SoCalGas, have a combined $600 million five-year syndicated revolving credit facility expiring in 2010, under which each utility individually may borrow up to $500 million, subject to the combined borrowing limit for both utilities of $600 million. Borrowings under the agreement bear interest at rates varying with market rates and SDG&E's credit rating. The agreement requires SDG&E to maintain, at the end of each quarter, a ratio of total indebtedness to total capitalization (as defined in the facility) of no more than 65 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. At December 31, 2005, SDG&E had no amounts outstanding under this facility.

LONG-TERM DEBT

December 31,

(Dollars in millions)	2005	2004
First mortgage bonds		
6.8% June 1, 2015	$ 14	$ 14
5.3% November 15, 2015	250	--
5.9% June 1, 2018	68	68
5.9% September 1, 2018	93	93
5.85% June 1, 2021	60	60
5% to 5.25% December 1, 2027	150	150
2.516% to 2.832%* January and February 2034	176	176
5.35% May 15, 2035	250	--
2.8275%* May 1, 2039	75	75
	1,136	636
Rate-reduction bonds, 6.31% to 6.37% at December 31, 2005 payable through 2007	132	198
Other bonds		
5.9% June 1, 2014	130	130
5.3% July 1, 2021	39	39
5.5% December 1, 2021	60	60
4.9% March 1, 2023	25	25
	254	254
	1,522	1,088
Current portion of long-term debt	(66)	(66)
Unamortized discount on long-term debt	(1)	--
Total	$ 1,455	$ 1,022

* After floating-to-fixed rate swaps expiring in 2009.

Maturities of long-term debt are:

(Dollars in millions)	
2006	$ 66
2007	66
2008	--
2009	--
2010	--
Thereafter	1,390
Total	$ 1,522

Callable Bonds

At the company's option, certain bonds are callable at various dates: $472 million in 2006 and $274 million after 2010. In addition, $500 million of bonds is callable subject to make-whole provisions.

First Mortgage Bonds

First mortgage bonds are secured by a lien on 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, 2005.

In November 2005, the company issued $250 million of first mortgage bonds maturing in 2015. In May 2005, the company issued $250 million of first mortgage bonds maturing in 2035.

Unsecured Long-term Debt

Various long-term obligations totaling $254 million at December 31, 2005 are unsecured.

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%. These bonds were issued to facilitate the 10percent rate reduction mandated by California's electric-restructuring law, which is described in Note 9. 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 property.

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.

Cash flow hedges

In September 2004, SDG&E entered into interest-rate swaps to exchange the floating rates on its $251 million Chula Vista Series 2004 bonds maturing from 2034 through 2039 for fixed rates. The swaps expire in 2009. At December 31, 2005 pre-tax income arising from the ineffective portion of interest-rate cash flow hedges included $4 million recorded in Other Income, Net on the Statements of Consolidated Income. The effect of the interest-rate cash flow hedges on other comprehensive income (loss) was immaterial for the years ended December 31, 2005 and 2004. The balance in Accumulated Other Comprehensive Income (Loss) at December 31, 2005, related to interest-rate cash flow hedges was reduced to zero due to the hedge ineffectiveness.

NOTE 3. FACILITIES UNDER JOINT OWNERSHIP

SONGS and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2005 were as follows:

(Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20%	91%
Utility plant in service	$ 39	$ 290
Accumulated depreciation and amortization	$ 2	$ 156
Construction work in progress	$ 21	$ 9

The company and the other owners each holds its interest as an undivided interest as tenants in common in the property. 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 (NRC), the Environmental Protection Agency, the U.S. Department of the Navy (the land owner), the CPUC and other regulatory bodies.

The company's share of decommissioning costs for the SONGS units is estimated to be $339 million in 2005 dollars. That amount includes the cost to decommission Units 2 and 3, and the remaining cost to complete Unit 1's decommissioning, which is currently in progress. Cost studies are updated every three years. The most recent update was 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, at which time sufficient funds are expected to have been collected to fully decommission SONGS, but may be extended by CPUC approval until 2022, when the units' NRC operating licenses terminate and the decommissioning of Units 2 and 3 would be expected to begin.

The amounts collected in rates are invested in externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations that establish maximum amounts for investments in equity securities (50 percent of a qualified trust and 60 percent of a nonqualified trust), international equity securities (20 percent) and securities of electric utilities having ownership interests in nuclear power plants (10 percent). Not less than 50 percent of the equity portion of the trusts must be invested passively. The securities held by the trust are considered available for sale. These trusts are shown on the Consolidated Balance Sheets at market value with the offsetting credits recorded in Asset Retirement Obligations and Regulatory Liabilities Arising from Removal Obligations.

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. Spent nuclear fuel has been removed from the Unit 1 Spent Fuel Pool and stored on-site in an independent spent fuel storage installation (ISFSI) licensed by the NRC. The remaining major work will include dismantling, removal and disposal of all remaining equipment and facilities (both nuclear and non-nuclear components), and decontamination of the site. These activities are expected to be completed in 2008. The ISFSI will be decommissioned after a permanent storage facility becomes available and the spent fuel is removed from the site by the U.S. Department of Energy. Unit 1's reactor vessel is expected to remain on site until Units 2 and 3 are decommissioned.

Trust investments include:

		December 31,	
(Dollars in millions)	Maturity dates	2005	2004
Municipal bonds	2006 - 2034	$ 54	$ 45
U.S. government issues	2006 - 2038	222	209
Cash and other securities	2006 - 2033	35	55
Equity securities		327	303
Total		$ 638	$ 612

Net earnings of the trust were $30 million in 2005, $46 million in 2004 and $82 million in 2003. Proceeds from sales of securities (which are reinvested) were $223 million in 2005, $237 million in 2004 and $266 million in 2003, including net gains of $3 million, $12 million and $4 million in 2005, 2004 and 2003, respectively. The net unrealized holding gains included in Asset Retirement Obligations and Regulatory Liabilities Arising from Removal Obligations on the Consolidated Balance sheets were $193 million, $182 million and $159 million at December 31, 2005, 2004 and 2003, respectively.

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 result in an increase in future customer contributions.

Discussion regarding the impact of SFAS 143 is provided in Note 1. Additional information regarding SONGS is included in Notes 9 and 11.

NOTE 4. INCOME TAXES

Reconciliations of the U.S. statutory federal income tax rate to the effective income tax rate are as follows:

	Years ended December 31, 2005	2004	2003
Statutory federal income tax rate	35 %	35 %	35 %
Depreciation	4	4	4
State income taxes - net of federal income tax benefit	6	5	7
Tax credits	(1)	(1)	(1)
Resolution of Internal Revenue Service audits	(13)	--	(12)
Other - net	(6)	(2)	(3)
Effective income tax rate	25 %	41 %	30 %

The components of income tax expense are as follows:

(Dollars in millions)	Years ended December 31, 2005	2004	2003
Current:			
Federal	$ 27	$ 107	$ 133
State	25	41	44
Total	52	148	177
Deferred:			
Federal	39	15	(20)
State	1	(12)	(6)
Total	40	3	(26)
Deferred investment tax credits	(3)	(3)	(3)
Total income tax expense	$ 89	$ 148	$ 148

On the Statements of Consolidated Income, federal and state income taxes are allocated between operating income and other income. The company 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 the company's having always filed a separate return. At December 31, 2005, income taxes payable to Sempra Energy are $6 million.

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

(Dollars in millions)	2005	2004
Deferred tax liabilities:		
Differences in financial and tax bases of utility plant	$ 591	$ 575
Regulatory balancing accounts	100	74
Loss on reacquired debt	14	20

Other	18	16
Total deferred tax liabilities	723	685
Deferred tax assets:		
Investment tax credits	23	27
Deferred compensation	18	29
State income taxes	20	43
Workers compensation and public liability insurance	6	6
Environmental liabilities	8	11
Other accruals not yet deductible	59	30
Other	5	2
Total deferred tax assets	139	148
Net deferred income tax liability	$ 584	$ 537

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

(Dollars in millions)	2005	2004
Current (asset) liability	$ (7)	$ 15
Noncurrent liability	591	522
Total	$ 584	$ 537

NOTE 5. EMPLOYEE BENEFIT PLANS

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 either final average or career salary.

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

Pension and other postretirement benefits costs and obligations are dependent on assumptions used in calculating such amounts. These assumptions include discount rates, expected return on plan assets, rates of compensation increase, health care cost trend rates, mortality rates, and other factors. These assumptions are reviewed on an annual basis prior to the beginning of each year and updated when appropriate. The company considers current market conditions, including interest rates, in making these assumptions.

Effective January 1, 2006 the company's other postretirement benefit plans were amended to integrate the benefits plan design across the California Utilities, resulting in a $52 million increase in the benefit obligation as of December 31, 2005.

December 31 is the measurement date for the pension and other postretirement benefit plans. The following table provides a reconciliation of the changes in the plans' projected benefit obligations during the latest two years, and the fair value of assets and a statement of the funded status as of the latest two year ends:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2005	2004	2005	2004
CHANGE IN PROJECTED BENEFIT OBLIGATION:				

Net obligation at January 1	$ 719	$ 662	$ 85	$ 76
Service cost	10	9	3	3
Interest cost	42	41	5	5
Plan amendments	--	--	52	--
Actuarial loss (gain)	33	40	(19)	6
Transfer of liability from Sempra Energy	35	28	2	--
Benefit payments	(52)	(61)	(4)	(5)
Net obligation at December 31	787	719	124	85
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	569	538	39	34
Actual return on plan assets	44	65	2	2
Employer contributions	21	20	7	8
Transfer of assets from Sempra Energy	34	7	--	--
Benefit payments	(52)	(61)	(4)	(5)
Fair value of plan assets at December 31	616	569	44	39
Benefit obligation, net of plan assets at December 31	(171)	(150)	(80)	(46)
Unrecognized net actuarial loss	138	94	1	19
Unrecognized prior service cost	4	7	46	(7)
Net recorded liability at December 31	$ (29)	$ (49)	$ (33)	$ (34)

The assets and liabilities of the pension and other postretirement benefit plans are affected by changing market conditions as well as when actual plan experience is different than assumed. Such events result in gains and losses. Investment gains and losses are deferred and recognized in pension and postretirement benefit costs over a period of years. If, as of the beginning of a year, unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active participants. The 10-percent corridor accounting method helps mitigate volatility of net periodic costs from year to year.

The net liability is recorded on the Consolidated Balance Sheets as follows:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2005	2004	2005	2004
Prepaid benefit cost	$ 4	$ 6	$ --	$ --
Accrued benefit cost	(33)	(55)	(33)	(34)
Additional minimum liability	(128)	(90)	--	--
Intangible asset	5	6	--	--
Regulatory asset	99	62	--	--
Accumulated other comprehensive income (pre-tax)	24	22	--	--
Net recorded liability	$ (29)	$ (49)	$ (33)	$ (34)

At December 31, 2005 and 2004, the company had an unfunded and a funded pension plan. The funded plan had benefit obligations in excess of its plan assets. The following table provides information for the funded plan at December 31:

(Dollars in millions)	2005	2004
Projected benefit obligation	$ 757	$ 694
Accumulated benefit obligation	$ 752	$ 692
Fair value of plan assets	$ 616	$ 569

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

	Pension Benefits			Other Postretirement Benefits		
(Dollars in millions)	2005	2004	2003	2005	2004	2003
Service cost	$ 10	$ 9	$ 14	$ 3	$ 3	$ 2
Interest cost	42	41	40	5	5	4
Expected return on assets	(44)	(40)	(33)	(2)	(3)	(1)
Amortization of:						
Transition obligation	--	--	--	--	--	1
Prior service cost	3	2	3	(1)	(1)	(1)
Actuarial loss	1	1	2	1	1	1
Regulatory adjustment	11	(55)	--	1	(8)	--
Transfer of retirees	12	--	--	(1)		
Total net periodic benefit cost (income)	$ 35	$ (42)	$ 26	$ 6	$ (3)	$ 6

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was enacted in December of 2003. The Act establishes a prescription drug benefit under Medicare (Medicare Part D) and a tax-exempt federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that actuarially is at least equivalent to Medicare Part D. The company and its actuarial advisors determined that benefits provided to certain participants actuarially will be at least equivalent to Medicare Part D, and, accordingly, the company expects to be entitled to a tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2005 and the net postretirement benefit cost for 2005 by immaterial amounts.

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

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	5.50%	5.66%	5.60%	5.66%
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	5.66%	6.00%	5.66%	6.00%
Expected return on plan assets	7.50%	7.50%	4.61%	4.76%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

The company utilizes a bond-pricing model that is tailored to the attributes of its pension and other postretirement plans to determine the appropriate discount rate to use for its benefit plans.

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.

	2005	2004
ASSUMED HEALTH CARE COST		
TREND RATES AT DECEMBER 31:		
Health-care cost trend rate	9.78 % *	19.00 % *
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	5.50 %	5.50 %
Year that the rate reaches the ultimate trend	2008	2008

* This is the weighted average of the increases for the company's health plans. The rate for these plans ranged from 8.50% to 10% in 2005 and from 10% to 20% in 2004.

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	$ 1	$ (1)
Effect on the health-care component of the accumulated other postretirement benefit obligation	$ 7	$ (6)

Pension Plan Investment Strategy

The asset allocation for Sempra Energy's pension trust (which includes the company's pension plan) at December 31, 2005 and 2004 and the target allocation for 2006 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2006	2005	2004
U.S. Equity	45 %	44 %	45 %
Foreign Equity	25	27	32
Fixed Income	30	29	23
Total	100 %	100 %	100 %

The company's investment strategy is to stay fully invested at all times and maintain its strategic asset allocation, keeping the investment structure relatively simple. The equity portfolio is balanced to maintain risk characteristics similar to the Morgan Stanley Capital International (MSCI) 2500 index with respect to industry and sector exposures and market capitalization. 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 Bond Index and Lehman Long Government Credit Bond Index. The plan does not invest in securities of Sempra Energy.

Investment Strategy for Postretirement Health Plans

The asset allocation for the company's postretirement health plans at December 31, 2005 and 2004 and the target allocation for 2006 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2006	2005	2004
U.S. Equity	25 %	23 %	25 %
Foreign Equity	5	6	6
Fixed Income	70	71	69
Total	100 %	100 %	100 %

The company's postretirement health plans that are not included in the pension trust (shown above) pay premiums to 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 $1 million to the pension plan and $15 million to its other postretirement benefit plans in 2006.

The following table reflects the total benefits expected to be paid for the next 10 years 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
2006	$ 54	$ 7
2007	$ 56	$ 8
2008	$ 61	$ 8
2009	$ 62	$ 9
2010	$ 64	$ 9
2011-2015	$ 347	$ 54

The expected future Medicare Part D subsidy payments are as follows:

(Dollars in millions)	
2006-2010	$ 2
2011-2015	$ 4

Savings Plan

The company offers a trusteed savings plan to all eligible employees. Eligibility to participate in the plan is immediate for salary deferrals. Subject to plan provisions, employees may contribute from one percent to 25 percent of their regular earnings, beginning with the start of employment. After one year of each employee's completed service, the company begins to make matching contributions. Employer contributions are equal to 50 percent of the first 6 percent of eligible base salary contributed by employees and, if certain company goals are met, an additional amount related to incentive compensation payments.

Employer contributions are initially invested in Sempra Energy common stock but may be transferred by the employee into other investments. Employee contributions are invested in Sempra Energy stock, mutual funds, or institutional trusts (the same investments to which employees may direct the employer contributions) as elected by the employee. Company contributions to the savings plan were $11 million in 2005, $10 million in 2004 and $8 million in 2003.

NOTE 6. 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 was issued. It encouraged 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 continued to account for stock-based compensation in accordance with the provisions of APBO 25. The issuance of SFAS 123R will require the company to begin accelerated recognition of stock-based compensation expense for participants who are eligible for retirement-related vesting, beginning in 2006. Discussion of SFAS 123R (a revision of SFAS 123) is provided in Note 1.

Sempra Energy subsidiaries record an expense for the plans to the extent that subsidiary employees participate in the plans or that the subsidiaries are allocated a portion of Sempra Energy's costs of the plans. SDG&E recorded expenses of $12 million, $9 million and $7 million in 2005, 2004 and 2003, respectively.

NOTE 7. FINANCIAL INSTRUMENTS

Fair Value Hedges

The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall cost of borrowing. The company's interest-rate swaps are discussed in Note 2.

Cash Flow Hedges

The company's interest-rate swaps to hedge cash flows are also discussed in Note 2.

Energy Contracts

At SDG&E, the use of derivative instruments is subject to certain limitations imposed by company policy and regulatory requirements. These instruments allow the company to estimate with greater certainty the effective prices to be received by the company and the prices to be charged to customers. The company records transactions for natural gas and electric energy contracts in Cost of Natural Gas and in Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. Unrealized gain and losses related to these derivatives have offsetting regulatory assets and liabilities on the Consolidated Balance Sheets to the extent derivative gains and losses will be recoverable from or payable to customers in future rates.

Fair Value of Financial Instruments

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

	2005		2004	
	Carrying	Fair	Carrying	Fair

(Dollars in millions)	Amount	Value	Amount	Value
Total long-term debt	**$** 1,522	$ 1,544	$ 1,088	$ 1,179
Preferred stock of subsidiaries	**$** 98*	$ 96	$ 100*	$ 100

* $19 million and $21 million in 2005 and 2004, respectively, of mandatorily redeemable preferred stock is included in Deferred Credits and Other Liabilities and in Other Current Liabilities on the Consolidated Balance Sheets.

The fair values of long-term debt and preferred stock are based on their quoted market prices or quoted market prices for similar securities.

NOTE 8. PREFERRED STOCK

	Call/ Redemption Price	December 31, 2005	2004
Not subject to mandatory redemption:		(in millions)	
$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, 750,000 and 850,000			
shares outstanding at December 31, 2005			
and December 31, 2004, respectively	$ 25.00	$ 19*	$ 21*

* At December 31, 2005 and 2004, $16 million and $19 million, respectively, were included in Deferred Credits and Other Liabilities, and $3 million and 2 million, respectively, were included in Other Current Liabilities on the Consolidated Balance Sheets.

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. 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. The $1.7625 Series has a sinking fund requirement to redeem 50,000 shares at $25 per share in each of 2006 and 2007; all remaining shares must be redeemed in 2008. On each of January 15, 2005 and January 15, 2006, SDG&E redeemed 100,000 shares.

NOTE 9. ELECTRIC INDUSTRY REGULATION

Background

One legislative response to the 2000 - 2001 power crisis resulted in the purchase by the 'DWR of a substantial portion of the power requirements of California's electricity users. In 2001, the DWR entered into long-term contracts with suppliers to provide power for the utility procurement customers of each of the California investor-owned utilities (IOUs). The CPUC has established the allocation of the power and its administrative responsibility, including collection of power contract costs from utility customers, among the IOUs. Beginning on January 1, 2003, the IOUs resumed responsibility for electric commodity procurement above their allocated share of the DWR's long-term contracts.

Department of Water Resources

The DWR operating agreement with SDG&E, approved by the CPUC, provides that SDG&E is acting as a limited agent on behalf of the DWR in undertaking energy sales and natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. Legal and financial responsibility associated with these activities continues to reside with the DWR. Therefore, commodity costs associated with long-term contracts allocated to SDG&E from the DWR (and the revenues to recover those costs) are not included in the Statements of Consolidated Income.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating the DWR's revenue requirement beginning in 2004 through the remaining life of the DWR contracts (2013). On June 30, 2005, the CPUC changed its prior decision and assigned SDG&E customers $422 million of the costs (instead of the $790 million pursuant to the prior decision). Such allocation does not affect SDG&E's net income, but does affect its customers' commodity rates. In August 2005, Southern California Edison (Edison), The Utility Reform Network and the California Large Energy Consumers Association(collectively the Parties) filed a Petition for Modification, not disputing the allocation of the DWR decision, but rather the schedule for reallocation. On December 1, 2005, the CPUC approved a decision that denied the Parties' petition to modify.

In December 2005, the CPUC approved a draft decision reallocating one of the state's DWR power contracts (Williams Energy "Power D") from SDG&E to Edison. The decision was modified to make the reallocation effective January 1, 2007, allowing SDG&E an additional year to plan for and acquire the necessary replacement resources. In the same decision, the CPUC rejected Edison's request to reallocate administration of Sempra Generation's DWR contract to SDG&E.

Power Procurement and Resource Planning

In 2001, the CPUC directed the IOUs to resume electric commodity procurement to cover their net short energy requirements by January 1, 2003 and also implemented legislation regarding procurement and renewables portfolio standards. In addition, the CPUC established a process for review and approval of the utilities' long-term resource and procurement plans, which is intended to identify forecasted needs for generation and transmission resources within a utility's service territory to support transmission grid reliability and to serve customers.

In June 2004, the CPUC approved a request by SDG&E to enter into new electric resource contracts to meet its short-term and long-term grid reliability needs, including the ten-year 573-Megawatt (MW) Otay Mesa Power Purchase Agreement (OMPPA) with Calpine Corp. (Calpine). The OMPPA was to begin January 1, 2008. In June 2005, the CPUC granted limited rehearing of its approval of the OMPPA and on February 16, 2005, the CPUC re-affirmed its approval of the OMPPA. However, several conditions precedent required by the OMPPA have not yet been satisfied. In lieu of the OMPPA, SDG&E and Calpine have entered into a non-binding letter of intent contemplating the negotiation of a definitive agreement for the sale of the Otay Mesa power plant to SDG&E. Any final, definitive agreement would require the approval of the CPUC and the bankruptcy court having jurisdiction over the Calpine case.

In July 2005, the CPUC also approved SDG&E's request for the construction (CPCN application) of $209 million in transmission facilities needed, in part, to provide full dispatchability of the Otay Mesa generation project. SDG&E has commenced construction of the OMPPA transmission upgrade project, spending $8 million through December 31, 2005.

The CPUC requires SDG&E to achieve a 20% renewable energy portfolio by 2010. SDG&E has entered into contracts with four developers for the purchase of energy from projects scheduled to begin operation between 2007 and 2016. SDG&E has entered into a 20-year contract to develop a 900-MW solar project in the Imperial Valley area of California. The first phase would provide 300 MW of power beginning in 2008 - 2010. The second phase would provide an option for an additional 300 MW beginning in 2010 - 2012. The third phase would provide the right of first refusal for another 300 MW of power beginning after 2012. The first two phases received CPUC approval in December 2005. SDG&E has also entered into a 20-year contract for development of a 205.5-MW wind project scheduled to begin in 2007 - 2008. The projects are expected to raise SDG&E's overall renewable portfolio to 13.3 % in 2010. The projects are contingent upon successful completion of new transmission lines.

San Onofre Nuclear Generating Station (SONGS)

On May 5, 2005, the CPUC granted SDG&E a rehearing to resolve what SDG&E has contended was a computational error in the CPUC's setting of revenue for SDG&E's share of the operating costs of SONGS. Any adjustment would be retroactive to January 1, 2004. If SDG&E is fully successful, its revenue for the period in which the rehearing is concluded would be increased by $10 million for each of 2004 and 2005. Final resolution is expected in the first half of 2006.

With the end of the Incremental Cost Incentive Mechanism in 2003, SDG&E's SONGS ratebase restarted at $0 on January 1, 2004 and, therefore, SDG&E's earnings from SONGS are now generally limited to a return on new additions to ratebase.

In 2004 Edison, the operator of SONGS, applied for CPUC approval to replace the steam generators at SONGS, stating that the work needed to be done in 2009 and 2010 for Units 2 and 3, respectively, and would require an estimated capital expenditure of $680 million (in 2004 dollars). As provided for in the SONGS Operating Agreement, SDG&E elected not to participate in the steam generator replacement project, which triggered a dispute under the operating agreement over the extent to which SDG&E's ownership share and its related share of SONGS's output would be reduced from its existing 20% interest if SDG&E does not participate in the project. In February 2005, an arbitrator issued a decision that would result in SDG&E's ownership interest in SONGS and its related share of SONGS's output being reduced to zero if SDG&E continues to decline to participate in the project.

SDG&E intervened in Edison's CPUC application and requested that the CPUC either deny Edison's application as premature, direct Edison to purchase the new steam generators but defer the replacement until it is warranted, or direct Edison to purchase SDG&E's share in the facility and offer back a long-term power purchase agreement in an amount equal to SDG&E's current share (430 MW). Hearings before the CPUC on Edison's application were completed in February 2005, and a final decision approving the steam generator project was issued on December 15, 2005. That decision sets cost recovery at a maximum cap of $782 million and requires a reasonableness review of all costs if total costs exceed $680 million. The decision also approves Edison's revised schedule, which provides for completion of the project for Unit 2 and Unit 3 by early 2010 and late 2010, respectively. To relinquish its ownership share and to address the arbitrator's decision, SDG&E is required to file by April 14, 2006, an application with the CPUC to determine the reasonableness of the transfer of all or part of SDG&E's share of SONGS to Edison, with a decision expected in 2007. The CPUC could require SDG&E to participate in the project and retain a share of SONGS or SDG&E could elect to participate in the project and retain its current 20-percent ownership share of SONGS. If SDG&E's ownership share of SONGS is reduced, SDG&E would seek to recover its net investment in SONGS made since January 1, 2004 ($86 million at December 31, 2005, including materials and supplies of $31 million) and any future SONGS investments made prior to the time the ownership reduction becomes effective, and a return on its investment in SONGS ratebase (including that portion of the $31 million that is transferred to plant by that time).

Spent Nuclear Fuel

SONGS owners have responsibility for the interim storage of spent nuclear fuel generated at SONGS until it is accepted by the Department of Energy (DOE) for final disposal. Spent nuclear fuel has been stored in the SONGS Units 1, 2 and 3 spent fuel pools and in the ISFSI. Movement of all spent fuel to the ISFSI was completed as of December 31, 2005, providing sufficient space for the Units 2 and 3 spent fuel pools to meet storage requirements through mid-2007 and mid-2008, respectively. The ISFSI has adequate storage capacity through 2022.

NOTE 10. OTHER REGULATORY MATTERS

Utility Ratemaking Incentive Awards

Performance-Based Regulation (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. It annually adjusts base rates from those of the prior year to provide for inflation based on the most recent Consumer Price Index (CPI) forecast, subject to minimum and maximum percentage increases that change annually.

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 specified benchmarks, the utility is rewarded or penalized certain dollar amounts. The three areas that have been eligible for PBR rewards or penalties are operational incentives based on measurements of safety, reliability and customer service; demand-side management (DSM) rewards based on the effectiveness of the DSM programs; and natural gas procurement rewards or penalties. As noted below, the latest Cost of Service proceeding established formula-based performance measures for customer service, safety and reliability.

PBR and DSM awards are not included in the company's earnings until CPUC approval of the award is received. During 2005, the incentive rewards approved and included in earnings consisted of $0.2 million related to SDG&E's Year 11 (2003-2004) natural gas PBR.

In October, 2005, the CPUC approved the settlement agreement between the California Utilities and the CPUC's DRA, resolving all outstanding shareholder earnings claims associated with DSM, energy efficiency and low-income energy efficiency programs through various dates, depending on the program. The decision provides for $73 million in awards, including interest, franchise fees, uncollectible amounts and awards earned in prior years that had not yet then been requested. Approximately $37 million of the $73 million award was included in fourth quarter 2005 income.

In October 2005, the CPUC also approved $8.2 million in PBR incentive awards for SDG&E's 2003 Distribution PBR performance report, relating to employee safety, customer service and electric reliability. This award is subject to refund in the event the current investigation of Edison's service quality incentive awards warrants a further investigation of PBR incentives for other utilities, including SDG&E. The CPUC's Consumer Protection and Safety Division is conducting an ongoing investigation of Edison's PBR incentive data reporting.

The cumulative amount of these awards that is subject to refund based on the outcome of the Border Price Investigation discussed in "Legal Proceedings" in Note 11 below is $8.5 million, the majority of which has been included in income.

Cost of Service

The California Utilities' proposed settlement of Phase II of their cost of service proceedings, addressing attrition allowances and performance-based incentive mechanisms, was approved by the CPUC and related performance measures and incentives were adopted. The CPUC's decision establishes an indexing methodology for post-test-year ratemaking that includes inflation adjustments and earnings-sharing mechanisms. The decision is retroactive to January 1, 2005 and is applicable to years 2005-2007. It eliminates earnings sharing and incentive awards for 2004.

For 2005 - 2007, the California Utilities' authorized base-rate revenues will be annually increased by the increase in the CPI, subject to minimum and maximum percentage increases that vary with the particular utility and increase yearly. The annual minimum increases range from 3.2% to 3.8% and the annual maximum percentage increases range from 4.2% to 4.8%. Pursuant to the indexing mechanisms, SDG&E increased its 2006 base margin revenue requirements by $33 million. The base margin adjustments included the recalibration of the 2005 base margin escalation to reflect actual index values before calculating the 2006 base margin revenue. For 2005-2007, any utility base-rate earnings that exceed the CPUC-authorized rate of return on ratebase plus 0.5 percentage point will be shared with customers, in proportions that vary with the amount of the excess, beginning with customers' receiving 75% of the excess, declining to 25% as the excess increases. The decision authorizes either utility to file for a suspension of the indexing and sharing mechanisms if its base-rate earnings for any year are at least 1.75 percentage points below its authorized rate of return and authorizes others to file for a suspension if either utility's base-rate earnings for any year are at least 1.75 percentage points above its authorized rate of return. The mechanisms would be automatically suspended for either utility if its base-rate earnings for 2005 or 2006 are at least 3 percentage points above or below its authorized rate of return.

The decision also establishes formula-based performance measures for customer service, safety and reliability. These provide symmetrical annual reward and penalty potentials aggregating approximately $14 million.

Cost of Capital

On December 15, 2005, the CPUC approved a return on equity (ROE) of 10.7% for SDG&E, an increase from its current ROE of 10.37%. SDG&E's authorized capital structure remains unchanged at 45.25% debt, 5.75% preferred stock and 49% common equity.

CPUC Investigation of Compliance with Affiliate Rules

In November 2004, the CPUC initiated the independent audit (known as the GDS audit) to evaluate energy-related holding company systems and affiliate activities undertaken by Sempra Energy within the service territories of the California Utilities. A draft audit report covering years 1997 through 2003 was provided to the CPUC's Energy Division in December 2005. The Energy Division is reviewing the draft audit report and plans to make the final audit report available in the first half of 2006. The scope of the audit is broader than the annual affiliate audit.

In May 2005, the California Utilities filed with the CPUC the results of the annual independent audit of the California Utilities' 2004 transactions with other Sempra Energy affiliates. Although the company does not agree with a finding of the auditor that utility procurement information was improperly provided to an affiliated risk-management consulting firm employed by Sempra Energy, the California Utilities have adopted the auditor's recommendation to perform risk management functions themselves rather than utilizing Sempra Energy's Risk Management Department.

"CPUC Investigation of Energy-Utility Holding Companies" and "Natural Gas Market OIR" (below) also discuss issues related to affiliate relationships.

CPUC Investigation of Energy-Utility Holding Companies

On October 27, 2005, the CPUC initiated a proceeding to re-examine the relationships between the California IOUs and their respective parent holding companies and other non-utility affiliates. It contemplates a review of the capital budgets, capital allocation processes, and dividend and capital retention policies of the utilities and their non-utility affiliates to better understand the amount of capital to be allocated for investment in energy infrastructure to meet California's need for reliable energy. The CPUC has broadly determined that, in appropriate circumstances, it could require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent it is not adequately funded through retail rates. The CPUC may propose additional rules or regulations to ensure that the utilities retain sufficient capital and the ability to access such capital to meet their customers' needs, and to address potential conflicts between the interests of utility ratepayers and those of non-utility affiliates to ensure that they do not undermine the utilities' ability to meet their public service obligations at the lowest possible cost. A preliminary schedule contemplates that any proposed rules and final rules would be issued for comment and final rules be adopted in the first half of 2006.

Natural Gas Industry Restructuring (GIR)

In December 2001, the CPUC issued a decision related to GIR, with implementation anticipated during 2002. On April 1, 2004, after many delays and changes, the CPUC issued a decision that adopts tariffs to implement the 2001 decision. However, that decision stayed implementation of the GIR tariffs until the CPUC issued a decision in Phase I of the Natural Gas Market Order Instituting Ratemaking (OIR) discussed below. At that time, the CPUC ordered the California Utilities to file a new proposal for system integration, firm access rights and off-system deliveries, as referenced below. The company is required to file a new Biennial Cost Allocation Proceeding (BCAP) application after the stay in the GIR implementation proceeding is lifted.

Natural Gas Market OIR

The CPUC's Natural Gas Market OIR was instituted in January 2004 and is being addressed in two phases. The focus of the Natural Gas Market OIR is the period from 2006 to 2016. The California Utilities have made comprehensive filings in the OIR, outlining a proposed market structure that is intended to create access to new natural gas supply sources, such as liquefied natural gas, for California. In their filings, the California Utilities proposed a framework to provide firm tradable access rights for intrastate natural gas transportation; provide SoCalGas with continued balancing account protection for intrastate transmission and distribution revenues, thereby eliminating throughput risk; and integrate their transmission systems so as to have common rates and rules. The California Utilities also proposed that the capital expenditures necessary to access new sources of supply be included in ratebase and that the total amount of the expenditures would be $200 million to $300 million. A decision on Phase I was issued in September 2004. The California Utilities were required to file separate applications to address system integration, firm access rights and off-system deliveries. The CPUC also determined that the ratemaking treatment and cost responsibility for any access-related infrastructure will be addressed in future applications to be filed when more is known about the particular project.

Evidentiary hearings on the system integration proposal were held in September 2005 to consider whether the transmission component of the natural gas transportation rates of the California Utilities should be equalized. System integration would allow customers in the California Utilities' service territories to access upstream supplies of natural gas on an equal basis. A decision on this phase is expected during the first quarter of 2006. Evidentiary hearings on infrastructure adequacy were held in August 2005 and addressed a variety of issues including the infrastructure adequacy of the California Utilities' transmission and storage facilities. Natural gas quality standards and interconnection requirements are being addressed in separate phases. In the second phase, to be addressed in mid-2006, the CPUC will consider establishing a system of firm access rights into the California Utilities' system and off-system deliveries.

The California Utilities proposed a methodology and framework to be used by the CPUC for granting pre-approval of new interstate transportation agreements. The Phase I decision approved the California Utilities' transportation capacity pre-approval procedures with some modifications. In 2005, SDG&E was granted approval for capacity contracts with El Paso Natural Gas Company (El Paso), Transwestern Pipeline Company and Kern River Gas Transmission Company, enabling the company to meet its identified goal to operate within the CPUC's approved planning range by November 1, 2006. All interstate transportation capacity under the pre-approved contracts will be used to transport natural gas supplies on behalf of the California Utilities' core residential and small commercial customers, and all costs of the capacity will be recovered in the customers' procurement rates.

Recovery of Certain Disallowed Transmission Costs

In September 2005, the FERC approved SDG&E's May 2005 settlement with the California Independent System Operator (ISO), which provides for refunds of ISO charges on the Arizona Public Service Co. and the Imperial Irrigation District ownership shares of the Southwest Powerlink, and resolves such unreimbursed charges going forward. Therefore, SDG&E recorded pre-tax income of $44 million in the third quarter of 2005.

California Utilities' Structural Changes

On January 4, 2006, the company announced an agreement that, subject to court approval, would settle the Continental Forge antitrust litigation, an identical proceeding in Nevada and class action lawsuits alleging price misreporting and wash trading. The agreement included that the California Utilities will seek approval from the CPUC to integrate their natural gas transmission facilities and to develop both firm, tradable natural gas receipt point rights for access to their combined intrastate transmission system and firm storage capacity rights on SoCalGas' underground natural gas storage system. Additional discussion of the settlement is provided in Note 11 under "Legal Proceedings."

Gain on Sale Rulemaking

A rulemaking was issued in September 2004 to standardize the treatment of gains on sales of property by the IOUs. This rulemaking may result in the adoption of a general ratemaking policy for allocation between utility shareholders and ratepayers of any gain or loss on sale of utility property. The CPUC will consider adopting a standard percentage allocation, probably between 5 percent and 50 percent to shareholders, rather than resolving such allocations on a case-by-case basis, as is now its practice. In unusual circumstances the CPUC would be able to depart from the standard allocation to be adopted. The CPUC intends to apply this standard percentage to sales of both depreciable and non-depreciable property. The rulemaking states that the new policy would replace the CPUC's current policy of allocating to shareholders all gain or loss to shareholders on sale to a municipality of a utility operating system. In November 2005, a proposed decision was issued that, if approved, would adopt a process for allocating gains on sale received by certain electric, natural gas, telecommunications and water utilities when they sell utility land, assets such as buildings, or other tangible or intangible assets formerly used to serve utility customers. In most cases, utility customers should receive 75% of the gain. The utilities' shareholders should receive the remaining 25% of the gain on sale. Opening and reply comments to the proposed decision were filed in January 2006. The final outcome of the rulemaking may be different than that proposed for comment in the order instituting the rulemaking.

Southern California Wildfires

In August 2005, the CPUC granted SDG&E full recovery, via its catastrophic event memorandum account (CEMA), of incurred costs ($40.8 million) associated with the fires.

NOTE 11. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

In January 2006, the company reached agreements, subject to court approval, to settle certain litigation arising out of the

2000 - 2001 California energy crisis. As a result of that settlement, the company increased its reserves at December 31, 2005, to $79 million, of which $76 million relates to the settled matters.

Other reserves of $3 million have been established for the litigation that is continuing at February 22, 2006. The uncertainties inherent in complex legal proceedings make it difficult to estimate with any degree of certainty the costs and effects of resolving these matters. Accordingly, costs ultimately incurred may differ materially from estimated costs and could materially adversely affect the company's business, cash flows, results of operations and financial condition.

Settlement Agreements

The litigation that is the subject of the settlement agreements is frequently referred to as the Continental Forge litigation, although the settlements also include other cases. The Continental Forge litigation, consisting of class-action and individual antitrust and unfair competition lawsuits consolidated in San Diego Superior Court, allege that Sempra Energy and the California Utilities, along with El Paso and several of its affiliates, unlawfully sought to control natural gas and electricity markets and claim damages of $23 billion after applicable trebling. Plaintiff class members include virtually all natural gas and electric consumers served by the California IOUs. The settlement of Continental Forge would also include the settlement of class action price reporting litigation, consisting of antitrust and unfair competition lawsuits coordinated in the San Diego Superior Court, alleging that Sempra Energy and its subsidiaries unlawfully misreported natural gas transactions to publishers of price indices and engaged in natural gas wash trading transactions. A second settlement agreement relates to class-action litigation brought by the Nevada Attorney General in Nevada Clark County District Court and involves virtually identical allegations to those in the Continental Forge litigation.

To settle the California and Nevada litigation, Sempra Energy would make cash payments in installments aggregating $377 million, of which $347 million relates to the Continental Forge and California class action price reporting litigation and $30 million relates to the Nevada antitrust litigation. Of the $377 million, $83 million would be paid within thirty days of final approval of the settlement by the San Diego County Superior Court and an additional $83 million would be paid on the first anniversary of that approval. Of the remaining amount, $27.3 million would be paid on the closing date of the settlement and $26.3 million would be paid on each successive anniversary of the closing date through the seventh anniversary of the closing date. At any time after the first anniversary of the closing date, Sempra Energy would have the option to prepay all or any portion of the remaining unpaid settlement amounts at a discount rate of 7%, with any partial prepayment applied to and reducing each remaining payment on an equal and proportionate basis.

Additional consideration for the California settlement includes an agreement that Sempra LNG would sell to the California Utilities, subject to CPUC approval, re-gasified liquefied natural gas from its liquefied natural gas terminal being constructed in Baja California, Mexico at the California border index price minus $0.02. The volumes to be purchased and sold would be up to 500 million cubic feet per day that Sempra Energy subsidiaries currently have contractual rights to purchase and that is not delivered or sold to Mexican entities. The California Utilities also would seek approval from the CPUC to integrate their natural gas transmission facilities and to develop both firm, tradable natural gas receipt point rights for access to their combined intrastate transmission system and SoCalGas' underground natural gas storage system. In addition, as described below, Sempra Generation voluntarily would reduce the price that it charges for power and limit the places at which it would deliver power under its contract with the DWR.

The California settlement is subject to the approval of the San Diego Superior Court, which has preliminarily approved the settlement, and authorized providing notice to the plaintiff class. The Los Angeles City Council has not yet voted to approve the City of Los Angeles's participation in the settlement and it may elect to continue pursuing its individual case against Sempra Energy and the California Utilities. If the City of Los Angeles decides not to participate, Sempra Energy may, at its option, either proceed with the settlement of the class action and other individual cases or terminate the entire agreement. The California Attorney General, the DWR, the California Energy Oversight Board, Edison, and Pacific Gas & Electric Company unsuccessfully challenged the proposed notice to the class based on their concern that, among other things, the releases in the settlement agreement may be sufficiently broad to encompass other proceedings against Sempra Energy and its subsidiaries to which they are parties. The final approval hearing for the Continental Forge settlement is scheduled to occur on June 8, 2006. The Nevada settlement is subject to approval by the Nevada Clark County District Court, which has not yet approved notice to the class or scheduled a final approval hearing. Both the California and Nevada settlements must be approved for either settlement to take effect, but Sempra Energy is permitted to waive this condition. The settlements are not conditioned upon approval by the CPUC, the DWR, or any other governmental or regulatory agency to be effective.

Sempra Energy recorded an after-tax charge of $116 million for the quarter ended December 31, 2005 (all at the parent company) to provide additional reserves to reflect the costs of the settlements that exceed amounts previously reserved. The additional and previously reserved amounts for the California and Nevada settlements aggregate $585 million (including $76 million at SDG&E and $155 million at SoCalGas) and fully provide for the present value of both the cash amounts to be paid in the settlements and the price discount to be provided on electricity expected to be delivered under the DWR contract.

Other Natural Gas Cases

On November 21, 2005, the California Attorney General and the CPUC filed a lawsuit against Sempra Energy and the California Utilities in San Diego County Superior Court alleging that in 1998 Sempra Energy and the California Utilities had intentionally misled the CPUC in ultimately obtaining CPUC approval to use the utilities' California natural gas pipeline capacity to enable Sempra Energy's non-utility subsidiaries to deliver natural gas to a power plant in Mexico. It further alleges that, as a result of insufficient utility pipeline capacity to serve both the power plant and California customers, SDG&E curtailed natural gas service to electric generators and large California commercial and industrial customers 17 times in 2000 - 2001, with service disruptions resulting in increased air pollution and higher electricity prices for California consumers from the use of oil as an alternate fuel source by electric generating plants. The lawsuit seeks statutory penalties of not less than $1 million, $2,500 for each of an unspecified number of instances of unfair business practices, and unspecified amounts of actual and punitive damages. It also seeks an injunction to require divestiture by Sempra Energy of non-utility subsidiaries to an extent to be determined by the court.

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, and included Sempra Energy, the California Utilities and Sempra Commodities, seeking recovery of damages alleged to aggregate in excess of $150 million (before trebling). The U.S. District Court dismissed the case in November 2004, determining that the FERC had exclusive jurisdiction to resolve the claims. In January 2005, plaintiffs filed an appeal with the Ninth Circuit Court of Appeals.

During 2004, 12 antitrust actions were filed against the company, alleging that energy prices were unlawfully manipulated by the reporting of artificially inflated natural gas prices to trade publications and by entering into wash trades. Several of those lawsuits seek class action certification. On April 8, 2005, one of those lawsuits, filed in the Nevada U.S. District Court, was dismissed, on the grounds that the claims asserted were preempted by federal law and the Filed Rate Doctrine. In June 2005, the three remaining lawsuits pending in the Nevada U.S. District Court were amended to name the California Utilities as defendants and to include conspiracy allegations similar to those made in the Continental Forge litigation. On December 27, 2005, the District Court dismissed these three actions, on the grounds that the claims asserted in these suits were preempted under federal law and the Filed Rate Doctrine. In addition, in June 2005, a class action lawsuit similar to the pending individual suits in the Nevada federal court was filed in the U.S. District Court for the Eastern District of California and has now been coordinated with the Nevada federal court proceeding. That action was stayed pending the court's determination of the motions to dismiss in the other federal cases. Sempra Energy will proceed to seek the dismissal of this action as well. With respect to the lawsuits coordinated before the San Diego Superior Court, on June 29, 2005, the court denied the defendants' motion to dismiss on preemption and Filed Rate Doctrine grounds. A separate motion to dismiss filed by Sempra Energy for improper joinder remains pending resolution by the court. On January 4, 2006, the parties agreed to settle the class action cases coordinated in the San Diego Superior Court as part of the overall Continental Forge settlement described above.

Electricity Cases

Various antitrust lawsuits, which seek class-action certification, allege that numerous entities, including Sempra Energy and certain subsidiaries, including SDG&E, that participated in the wholesale electricity markets unlawfully manipulated those markets. Collectively, these lawsuits allege damages against all defendants in an aggregate amount in excess of $16 billion (before trebling). In January 2003, the federal court granted a motion to dismiss one of these lawsuits, filed by the Snohomish County, Washington Public Utility District against Sempra Energy and certain non-utility subsidiaries, among others, 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. In September 2004, the Ninth Circuit U.S. Court of Appeals affirmed the district court's ruling, finding that the FERC, not civil courts, has exclusive jurisdiction over the matter. Snohomish County appealed the Ninth Circuit decision to the U.S. Supreme Court, which, in June 2005, declined to review the decision. The company believes that this decision provides a precedent for the dismissal on the basis of federal preemption and the Filed Rate Doctrine of the other lawsuits against the Sempra Energy companies claiming manipulation of the electricity markets. On October 4, 2005, on the basis of federal preemption and Filed Rate grounds, the San Diego Superior Court dismissed with prejudice the initial consolidated cases that claimed that energy companies, such as the Sempra Energy companies, manipulated the wholesale electricity markets. In December 2005, plaintiffs filed an appeal in that case.

CPUC 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. The Administrative Law Judge's (ALJ) proposed decision was rejected by the CPUC in December 2004.

The portion of this investigation relating to the California Utilities is still open. If the investigation were to determine that the conduct of either of the California Utilities contributed to the natural gas price spikes that occurred during the investigation period, 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. At December 31, 2005, the cumulative amount of these shareholder awards, substantially all of which has been included in income, was $8.5 million.

The CPUC may hold additional hearings to consider whether other companies, including other California utilities, contributed to the natural gas price spikes, or issue an order terminating the investigation. Discovery is ongoing and initial testimony was filed in November 2005. Hearings are expected to begin in late July 2006.

FERC Refund Proceedings

The FERC is investigating prices charged to buyers in the California Power Exchange (PX) and ISO markets by various electric suppliers. In December 2002, a FERC ALJ issued preliminary findings indicating that the PX and ISO owe power suppliers $1.2 billion for the October 2, 2000 through June 20, 2001 period (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). In March 2003, the FERC adopted its ALJ's findings, but changed the calculation of the refund by basing it on a different estimate of natural gas prices. The March 2003 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 for the same time period. Pending in the Ninth Circuit are various parties' appeals on aspects of the FERC's order. In April 2005, the Ninth Circuit heard oral argument on issues relating to the scope of the refund proceeding and whether the FERC had jurisdiction to order refunds from governmental entities. The Ninth Circuit determined in September 2005 that FERC did not have jurisdiction to order refunds from governmental entities. The California IOUs, including SDG&E, have now filed claims with the various governmental entities to recoup monies paid over and above the just and reasonable rate for power in the 2000-2001 time frame. A decision on the remaining issues argued before the Court in April 2005 remains pending.

SDG&E has been awarded $137 million through December 31, 2005, in settlement of certain claims against electricity suppliers related to the 2000-01 California energy crisis. The net proceeds of these settlements are applied to reduce electric rates.

FERC Manipulation Investigation

The FERC is separately investigating whether there was manipulation of short-term energy markets in the western United States 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 periods 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.

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. The 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 through a settlement, which documents the ISO's finding that SDG&E did not engage in market activities in violation of the ISO or PX tariffs, and in which SDG&E agreed to pay $27,792 into a FERC-established fund.

Natural Gas Contracts

SDG&E buys natural gas under short-term contracts. Purchases are from various Southwest U.S. and Canadian suppliers and are primarily based on monthly spot-market prices. The company 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 2006 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. In accordance with regulatory directives, SDG&E reconfigured its pipeline capacity portfolio in November 2005 to secure firm transportation rights from a diverse mix of U.S. and Canadian supply sources for its projected core customer natural gas requirements.

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 2006, SoCalGas provides SDG&E six billion cubic feet of storage capacity. In February 2006, SDG&E entered into two agreements with SoCalGas to extend the storage capacity to 2008. The agreements are pending to the CPUC's approval.

At December 31, 2005, the future minimum payments under existing natural gas storage and transportation contracts were:

(Dollars in millions)

2006	$ 22
2007	15
2008	13
2009	10
2010	10
Thereafter	112
Total minimum payments	$ 182

Total payments under natural gas contracts were $455 million in 2005, $347 million in 2004 and $274 million in 2003.

Purchased-Power Contracts

For 2006, SDG&E expects to receive 43 percent of its customer power requirements from DWR allocations. Of the remaining requirements, SONGS is expected to account for 17 percent, long-term contracts for 19 percent (of which 7 percent is provided by renewable contracts expiring on various dates through 2025), Palomar for 12 percent and spot market purchases for 9 percent. The long-term contracts expire on various dates through 2032.

At December 31, 2005, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)

2006	$ 247
2007	248
2008	288
2009	283
2010	282
Thereafter	2,627
Total minimum payments	$ 3,975

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 $363 million in 2005, $329 million in 2004 and $396 million in 2003.

Leases

SDG&E has operating leases on real and personal property expiring at various dates from 2006 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2 percent to 5 percent. The rentals payable under these leases are determined on both fixed and percentage bases, and most leases contain extension options which are exercisable by the company.

At December 31, 2005, the minimum rental commitments payable in future years under all noncancellable leases were as follows:

(Dollars in millions)

2006	$	19
2007		17
2008		12
2009		9
2010		8
Thereafter		19
Total future rental commitments	$	84

Rent expense for operating leases totaled $22 million in 2005, $20 million in 2004 and $20 million in 2003.

Construction Projects

In addition to the recurrent expenditures for plant improvements, the company will spend $500 million in 2006 to purchase the 550-MW Palomar power plant, which is currently being constructed by Sempra Generation, and other costs associated with the plant. The capitalized costs through December 31, 2005 are recorded as construction work in progress in Utility Plant on the Consolidated Balance Sheets.

Guarantees

As of December 31, 2005, the company did not have any outstanding guarantees.

Department Of Energy Nuclear Fuel Disposal

The Nuclear Waste Policy Act of 1982 made the DOE responsible for the disposal of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay by the DOE will lead to increased costs 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, 2005, the aggregate unexpended amount of this commitment was $67 million. Capital expenditures for underground conversions were $32 million in 2005, $23 million in 2004 and $28 million in 2003.

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. 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. The company is required to obtain numerous governmental permits, licenses and other approvals to construct facilities and operate its businesses, and must spend significant sums on environmental monitoring, pollution control equipment and emissions fees. 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 $9 million in 2005, $9 million in 2004 and $5 million in 2003. 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 probability that these costs will be recovered in rates.

The environmental issues currently facing the company or resolved during the last three years include investigation and remediation of its manufactured-gas sites (two completed as of December 31, 2005 and site-closure letters received), 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. Not including the liability for SONGS marine mitigation, which SDG&E is participating in jointly with Edison, at December 31, 2005, the company's accrued liability for environmental matters was $17.5 million, of which $6.3 million is related to manufactured-gas sites, $10.3 million to cleanup at SDG&E's former fossil-fueled power plants, and $0.9 million to waste-disposal sites used by the company (which has been identified as a PRP). The majority of 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 provides coverage of $300 million, the maximum amount available. In addition, the Price-Anderson Act provides for up to $10.5 billion of secondary financial protection. 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 to provide the secondary financial protection. SDG&E's total share would be up to $40 million, subject to an annual maximum assessment of $6 million, unless a default were to occur by any other SONGS owner. In the event the secondary financial protection limit were insufficient to cover the liability loss, SDG&E could be subject to an additional assessment.

SDG&E and the other owners of SONGS have $2.75 billion of nuclear property, decontamination and debris removal insurance and up to $490 million for outage expenses and replacement power costs 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, after a waiting period of 12 weeks. The insurance is provided through a mutual insurance company, through which insured members are subject to retrospective premium assessments (up to $8.65 million in SDG&E's case).

The nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for non-certified acts (as defined by the Terrorism Risk Insurance Act) of terrorism-related SONGS losses, including replacement power costs. There are industry aggregate limits of $300 million for liability claims and $3.24 billion for property claims, including replacement power costs, for non-certified acts of terrorism. These limits are the maximum amount to be paid to members who sustain losses or damages from these non-certified terrorist acts. For certified acts of terrorism, the individual policy limits stated above apply.

Concentration Of Credit Risk

The company maintains credit policies and systems to manage overall credit risk. These policies include an evaluation of potential counterparties' financial condition and an assignment of credit limits. These credit limits are established based on risk and return considerations under terms customarily available in the industry. The company grants credit to customers and counterparties, substantially all of whom are located in its service territories, which cover all of San Diego County and an adjacent portion of Orange County.

NOTE 12. QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarters ended

(Dollars in millions)	March 31	June 30	September 30	December 31
2005				
Operating revenues	$ 621	$ 539	$ 601	$ 751
Operating expenses	553	487	497	692
Operating income	$ 68	$ 52	$ 104	$ 59
Net income	$ 60	$ 30	$ 104	$ 73
Dividends on preferred stock	1	1	2	1
Earnings applicable to common shares	$ 59	$ 29	$ 102	$ 72
2004				
Operating revenues	$ 580	$ 536	$ 550	$ 608
Operating expenses	518	488	486	526
Operating income	$ 62	$ 48	$ 64	$ 82
Net income	$ 51	$ 31	$ 62	$ 69
Dividends on preferred stock	1	1	2	1
Earnings applicable to common shares	$ 50	$ 30	$ 60	$ 68

Operating revenues for the fourth quarter of 2005 included $23 million before-tax from the 2005 Internal Revenue Service decision relating to the sale of the company's former South Bay power plant. Operating expenses for the third quarter of 2005 included $44 million before-tax California energy crisis litigation costs, offset by $38 million before-tax related to the 2005 recovery of line losses and grid management charges arising from the favorable settlement with the ISO. Net income for the third quarter of 2005 included the favorable resolution of prior years' income-tax issues.

Operating revenues and expenses in the fourth quarter of 2004 included a $34 million favorable impact of the final Cost of Service decision, offset by $19 million of litigation expense.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f). The company has designed and maintains disclosure controls and procedures to ensure that information required to be disclosed in the company's reports 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.

During the year ended December 31, 2005, management outsourced certain human resource, payroll, and employee benefit functions to a third-party service provider, and implemented a new software application that automates the calculation of the income tax provision. The changes strengthen the design and effectiveness of the internal controls and improve the efficiency of these systems. As part of the conversion processes, management performed substantial testing of related internal controls intended to provide reasonable assurances that the converted data and subsequent ongoing process meet the company's objective to provide reliable financial reporting. Management has determined that the design of the controls surrounding these new processes satisfies the control objectives and that the controls are operating effectively.

Except for these changes, there have been no changes in the company's internal controls over financial reporting during the company's most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the company's internal controls over financial reporting.

The company evaluates the effectiveness of its internal control over financial reporting based on the framework in *Internal Control--Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures as of December 31, 2005, the end of the period covered by this report. Based on that evaluation, the company's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures were effective at the reasonable assurance level.

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 2006 annual meeting of shareholders. The information required on the companies' executive officers is set forth below.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age*	Position*
Edwin A. Guiles	56	Chairman and Chief Executive Officer
Debra L. Reed	49	President and Chief Operating Officer
James P. Avery	49	Senior Vice President, Electric
Steven D. Davis	50	Senior Vice President, External Relations and Chief Financial Officer
William L. Reed	54	Senior Vice President, Regulatory and Strategic Planning
Anne S. Smith	52	Senior Vice President, Customer Service
Lee M. Stewart	60	Senior Vice President, Gas Operations
Robert M. Schlax	50	Vice President, Controller and Chief Accounting Officer

* As of February 22, 2006.

Except for Mr. Schlax, each executive officer has been an officer or employee of Sempra Energy or one of its subsidiaries for more than five years. Prior to joining the company in 2005, Mr. Schlax was Chief Financial Officer, Treasurer and Vice President of Finance of Mercury Air Group, Inc. Except for Mr. Avery, each executive officer of San Diego Gas & Electric Company holds the same position at Southern California Gas Company.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference from "Election of Directors" and "Executive Compensation" in the Information Statement prepared for the May 2006 annual meeting of shareholders.

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

Security Ownership of Certain Beneficial Owners

The security ownership information required by Item 12 is incorporated by reference from "Share Ownership" in the Information Statement prepared for the May 2006 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 Information Statement prepared for the May 2006 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

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 82 of this report.

(b) Reports on Form 8-K

The following reports on Form 8-K were filed after September 30, 2005:

Current Report on Form 8-K filed November 2, 2005, including as exhibits Sempra Energy's press release of November 2, 2005, giving the financial results for the three months ended September 30, 2005, and related Income Statement Data by Business Unit.

Current Report on Form 8-K filed November 17, 2005, discussing the status of the company's energy crisis era legal proceedings.

Current Report on Form 8-K filed November 17, 2005, discussing the company's $250 million bond offering.

Current Report on Form 8-K filed November 23, 2005, discussing the status of an action filed by the Attorney General of California against the company.

Current Report on Form 8-K filed January 5, 2006, announcing the agreement to settle certain litigation and the effect of the settlements on the company's results of operations and financial condition for the year ended December 31, 2005.

Current Report on Form 8-K filed February 22, 2006, including as exhibits Sempra Energy's press release of February 22, 2006, giving the financial results for the three months ended December 31, 2005, and related Income Statement Data by Business Unit.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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 reports dated February 21, 2006 relating to the financial statements of San Diego Gas and Electric Company (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company's adoption of Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143,* effective December 31, 2005) and management's report on the effectiveness of internal control over financial reporting, appearing in and incorporated by reference in this Annual Report on Form 10-K of San Diego Gas and Electric Company for the year ended December 31, 2005.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 21, 2006

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SAN DIEGO GAS & ELECTRIC COMPANY,
(Registrant)

By: /s/ Edwin A. Guiles

[redacted]

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
[redacted]		
Principal Executive Officer: Edwin A. Guiles Chairman and Chief Executive Officer	/s/ Edwin A. Guiles [redacted]	February 13, 2006
Principal Financial Officer: Steven D. Davis Senior Vice President, External Relations and Chief Financial Officer	/s/ Steven D. Davis [redacted]	February 13, 2006
Principal Accounting Officer: Robert M. Schlax Vice President, Controller and Chief Accounting Officer	/s/ Robert M. Schlax [redacted]	February 13, 2006
Directors:		
Edwin A. Guiles, Chairman	/s/ Edwin A. Guiles	February 13, 2006

[redacted]

Debra L. Reed, Director	/s/ Debra L. Reed	February 13, 2006
	[redacted]	
Frank H. Ault, Director	/s/ Frank H. Ault	February 13, 2006
	[redacted]	

EXHIBIT INDEX

The Forms S-8, 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 Statement No. 2-49810, Exhibit 2A.).

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

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

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

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

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

4.07 Forty-Ninth Supplemental Indenture dated June 1, 2004. (2004 Sempra Energy Form 10-K, Exhibit 4.07).

4.08 Fiftieth Supplemental Indenture Dated as of May 19, 2005. (8-K filed on May 19, 2005, Exhibit 4.1).

4.09 Fifty-First Supplemental Indenture Dated as of November 17, 2005. (8-K filed on November 17, 2005, Exhibit 4.1).

Exhibit 10 -- Material Contracts

10.01 Form of Continental Forge and California Class Action Price Reporting Settlement Agreement dated as of January 4, 2006 (8-K filed on January 5, 2006, Exhibit 99.1)

10.02 Form of Nevada Antitrust Settlement Agreement dated as of January 4, 2006 (8-K filed on January 5, 2006, Exhibit 99.2)

10.03 Text of Stipulation in Continental Forge Litigation (8-K filed on September 9, 2005, Exhibit 99.1)

10.04 San Diego Gas & Electric Underwriting Agreement dated November 14, 2005 (8-K filed on November 17, 2005, Exhibit 1.1)

10.05 San Diego Gas & Electric Pricing Agreement dated November 14, 2005 (8-K filed on November 17, 2005, Exhibit 1.2)

10.06 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).

10.07 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).

10.08 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).

10.09 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

10.10 Form of Severance Pay Agreement (2004 Sempra Energy 10-K, Exhibit 10.10).

10.11 Sempra Energy 2005 Deferred Compensation Plan (San Diego Gas & Electric Form 8-K filed on December 07, 2004, Exhibit 10.1).

10.12 Sempra Energy Employee Stock Incentive Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.1).

10.13 Sempra Energy Amended and Restated Executive Life Insurance Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.2).

10.14 Sempra Energy Excess Cash Balance Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.3).

10.15 Form of Sempra Energy 1998 Long Term Incentive Plan Performance-Based Restricted Stock Award (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.4).

10.16 Form of Sempra Energy 1998 Long Term Incentive Plan Nonqualified Stock Option Agreement (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.5).

10.17 Form of Sempra Energy 1998 Non-Employee Directors' Stock Plan Nonqualified Stock Option Agreement (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.6).

10.18 Sempra Energy Supplemental Executive Retirement Plan (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.7).

10.19 Neal Schmale Restricted Stock Award Agreement (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.8).

10.20 Severance Pay Agreement between Sempra Energy and Donald E. Felsinger (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.9).

10.21 Severance Pay Agreement between Sempra Energy and Neal Schmale (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.10).

10.22 Sempra Energy Executive Personal Financial Planning Program Policy Document (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.11).

10.23 2003 Sempra Energy Executive Incentive Plan B (2003 Sempra Energy Form 10-K, Exhibit 10.10).

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

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

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

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

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

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

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

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

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

Financing

10.33 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 (1997 Enova Corporation Form 10-K, Exhibit 10.34).

10.34 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).

10.35 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).

10.36 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).

10.37 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).

10.38 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).

10.39 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).

10.40 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).

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

10.42 Loan agreement with the City of Chula Vista in connection with the issuance of $251.3 million of Industrial Development Revenue Refunding Bonds, dated as of June 1, 2004 (2004 Sempra Energy Form 10-K, Exhibit 10.43).

Nuclear

10.43 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).

10.44 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.43 above)(1994 SDG&E Form 10-K, Exhibit 10.56).

10.45 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 10.43 above)(1994 SDG&E Form 10-K, Exhibit 10.57).

10.46 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 10.43 above)(1996 Form 10-K, Exhibit 10.59).

10.47 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 10.43 above)(1996 Form 10-K, Exhibit 10.60).

10.48 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 10.43 above)(1999 Form 10-K, Exhibit 10.26).

10.49 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 10.43 above)(1999 Form 10-K, Exhibit 10.27).

10.50 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 10.43 above)(2003 Sempra Energy Form 10-K, Exhibit 10.42).

10.51 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).

10.52 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 10.51 above)(1996 Form 10-K, Exhibit 10.62).

10.53 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 10.51 above)(1996 Form 10-K, Exhibit 10.63).

10.54 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 10.51 above)(1999 Form 10-K, Exhibit 10.31).

10.55 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 10.51 above)(1999 Form 10-K, Exhibit 10.32).

10.56 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 10.51 above)(2003 Sempra Energy Form 10-K, Exhibit 10.48).

10.57 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).

10.58 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

10.59 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).

10.60 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).

10.61 Firm Transportation Service Agreement, dated October 13, 1994 between Pacific Gas Transmission Company (succeeded by TransCanada Pipelines - GTN Systems) and San Diego Gas & Electric Company (1997 Enova Corporation Form 10-K, Exhibit 10.60).

Other

10.62 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, 2005, 2004, 2003, 2002 and 2001.

Exhibit 21 -- Subsidiaries

21.01 Schedule of Subsidiaries at December 31, 2005.

Exhibit 23 -- Consent of Independent Registered Public Accounting Firm, page 80.

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

AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
APBO	Accounting Principles Board Opinion
ARB	Accounting Research Bulletin
BCAP	Biennial Cost Allocation Proceeding
California Utilities	Southern California Gas Company and San Diego Gas& Electric
Calpine	Calpine Corporation
CEC	California Energy Commission
CEMA	Catastrophic Event Memorandum Act
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
DOE	Department of Energy
DSM	Demand Side Management

DWR	Department of Water Resources
Edison	Southern California Edison Company
EITF	Emerging Issues Task Force
El Paso	El Paso Natural Gas Company
EMFs	Electric and Magnetic Fields
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation Number
GAAP	Generally Accepted Accounting Principles
GIR	Gas Industry Restructuring
IOUs	Investor-Owned Utilities
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Facility
ISO	Independent System Operator
LIFO	Last in first out inventory costing method
mmbtu	Million British Thermal Units (of natural gas)
MSCI	Morgan Stanley Capital International

MW	Megawatt
NRC	Nuclear Regulatory Commission
OIR	Order Instituting Ratemaking
OMPPA	Otay Mesa Power Purchase Agreement
PBR	Performance-Based Ratemaking/Regulation
PG&E	Pacific Gas and Electric Company
PGE	Portland General Electric Company
PIER	Public Interest Energy Research
PRP	Potentially Responsible Party
PX	Power Exchange
QF	Qualifying Facility
RD&D	Research Development and Demonstration
RMC	Risk Management Committee
RMD	Risk Management Department
ROE	Return on Equity
SDG&E	San Diego Gas & Electric Company
SFAS	Statement of Financial Accounting Standards

SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
VaR	Value at Risk
VIE	Variable Interest Entity

EXHIBIT 12.1
SAN DIEGO GAS & ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES
AND PREFERRED STOCK DIVIDENDS
(Dollars in millions)

	2001	2002	2003	2004	2005
Fixed Charges and Preferred Stock Dividends:					
Interest	$ 96	$ 83	$ 78	$ 71	$ 77
Interest portion of annual rentals	3	2	2	2	3
Total fixed charges	99	85	80	73	80
Preferred stock dividends (1)	11	9	9	8	6
Combined fixed charges and preferred stock dividends for purpose of ratio	$ 110	$ 94	$ 89	$ 81	$ 86
Earnings:					
Pretax income from continuing operations	$ 324	$ 300	$ 488	$ 361	$ 356
Total fixed charges (from above)	99	85	80	73	80
Less: interest capitalized	1	1	1	1	1
Total earnings for purpose of ratio	$ 422	$ 384	$ 567	$ 433	$ 435
Ratio of earnings to combined fixed charges and preferred stock dividends	3.84	4.09	6.37	5.35	5.06

(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 Significant Subsidiaries

at December 31, 2005

Subsidiary	State of Incorporation or Other Jurisdiction
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 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; and

2. 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 control over financial reporting.

February 22, 2006

/s/ Edwin A. Guiles

Edwin A. Guiles

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Steven D. Davis, 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 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; and

2. 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 control over financial reporting.

February 22, 2006

/s/ Steven D. Davis

Steven D. Davis

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, 2005 (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 22, 2006

/s/Edwin A. Guiles

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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, 2005 (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 22, 2006

/s/Steven D. Davis

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Steven D. Davis

Chief Financial Officer