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, 2006

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________ to ____________

Commission file number 1-3779

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

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

8326 Century Park Court, San Diego, California 92123
(Address of principal executive offices)
(Zip Code)

(619) 696-2000
(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
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

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

Yes ______ No X

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 ______ No X

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___ No _______

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

___X___

Indicate by check mark whether the registrant is 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 87. Glossary on page 91.

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2006 was $0.

Registrant’s common stock outstanding as of January 31, 2007, was wholly owned by Enova Corporation.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Information Statement prepared for the May 2007 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, the Federal Energy Regulatory Commission and other environmental and 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 Sempra 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 the company. These risk factors could affect the actual results of the company and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of the company. 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, the company'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 the company 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, the uniform systems of accounts and long-term resource procurement. The CPUC conducts various reviews of utility performance (which may include reasonableness and prudency reviews of capital expenditures, natural gas and electricity procurement, and other costs, and reviews and audits of the company's records) 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.

For major capital programs, the company may expend funds prior to receiving regulatory approval to proceed with the capital project. If the project does not receive regulatory approval or a decision is made not to proceed with the project, the company may not be able to recover the amount expended for that project.

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 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 applies Performance-Based Regulation (PBR) to the Sempra 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, the rates of return on transmission investments 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 percent interest in the San Onofre Nuclear Generating Station (SONGS), a 2,150 megawatt (MW) 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 Sempra Utilities' future results of operations, financial condition and cash flows 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 Sempra Utilities. During 2006, Sempra Energy and the Sempra 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. However, the companies remain defendants in several additional lawsuits arising out of the energy crisis, including various antitrust actions. Sempra Energy and the Sempra Utilities have expended and continue to expend substantial amounts defending these lawsuits and in connection with related investigations and regulatory proceedings. They have established reserves that they believe to be appropriate for the ultimate resolution of these remaining matters. However, uncertainties inherent in complex legal proceedings make it difficult to estimate with any degree of certainty the costs and effects of resolving legal matters. Accordingly, costs ultimately incurred may differ materially from estimated costs and could materially adversely affect Sempra Energy's and the Sempra Utilities' business, cash flows, results of operations and financial condition.

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

SDG&E has significant environmental compliance costs, and future environmental compliance costs could adversely affect SDG&E's profitability.

SDG&E is subject to extensive federal, state and local statutes, rules and regulations relating to environmental protection, including, in particular, global warming and greenhouse gas (GHG) emissions. It is required to obtain numerous governmental permits, licenses and other approvals to construct and operate its business. Additionally, to comply with these legal requirements, it must spend significant sums on environmental monitoring, pollution control equipment and emissions fees. The company also is generally responsible for all on-site liabilities associated with the environmental condition of its electric generation facilities and other energy projects, regardless of when the liabilities arose and whether they are known or unknown. If SDG&E fails to comply with applicable environmental laws, it may be subject to penalties, fines and/or curtailments of its operations.

The scope and effect of new environmental laws and regulations, including their effects on current operations and future expansions, are difficult to predict. Increasing international, national, regional and state-level concerns as well as new or proposed legislation may have substantial effects on operations, operating costs, and the scope and economics of proposed expansion. In particular, state-level laws and regulations as well as proposed national and international legislation relating to greenhouse gases (including carbon dioxide, methane, nitrous oxide, hydrofluorocarbon, perfluorocarbon, and sulfur hexafluoride) may limit or otherwise adversely affect the operations of the company. The Sempra Utilities may be affected if costs are not recoverable in rates and because the effects of significantly tougher standards may cause rates to increase to levels that substantially reduce customer demand and growth.

In addition, existing and future laws and regulation on mercury, nitrogen oxide and sulfur dioxide emissions could result in requirements for additional pollution control equipment or emission fees and taxes that could adversely affect the company. Moreover, existing rules and regulations may be interpreted or revised in ways that may adversely affect the company and its facilities and operations. Additional information on these matters is provided in Note 9 of the notes to the Consolidated Financial Statements in the 2006 Annual Report to Shareholders herein.

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 generation plants, electric transmission facilities, and natural gas pipelines and storage facilities 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.

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.

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 and long-term resource procurement, except as described below under “United States Utility Regulation.” The CPUC also has jurisdiction over the proposed construction of major new electric transmission, electric distribution and natural gas transmission facilities. The CPUC conducts various reviews of utility performance, conducts audits of the company’s records for compliance with regulatory guidelines, and conducts investigations into various matters, such as deregulation, competition and the environment, to determine its future policies. The CPUC also regulates the interactions and transactions of the utilities with Sempra Energy, as discussed further in Note 10 of the notes to Consolidated Financial Statements herein.

The California Energy Commission (CEC) establishes 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 statewide 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.

Assembly Bill 32, the California Global Warming Solutions Act of 2006, makes the California Air Resources Board (CARB) responsible for monitoring and reducing GHG emissions. The bill requires CARB to develop and adopt a comprehensive plan for achieving real, quantifiable and cost-effective GHG emission reductions including, among other things, a statewide GHG emissions cap, mandatory reporting rules, and regulatory and market mechanisms to achieve reductions of GHG emissions. CARB is a part of the California Environmental Protection Agency, an organization which reports directly to the Governor's Office in the Executive Branch of California State Government. The California Legislature established CARB in 1967 to attain and maintain healthy air quality and to conduct research into the causes of and solutions to air pollution. CARB is made up of eleven members appointed by the Governor.

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 reanalyze 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), Chula Vista (2015), San Diego (2020) and Coronado (2028) and the natural gas franchises with the county of San Diego (2029) and the city of Escondido (2035).

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

The company is engaged in the purchase, sale, and distribution of natural gas. The company's resource planning, natural gas procurement, contractual commitments and related regulatory matters are discussed below and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 10 and 11 of the notes to Consolidated Financial Statements herein.

Customers

For regulatory purposes, customers are classified as 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, and 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., U.S. Rockies and Canada. The company purchases natural gas under short-term contracts, which are primarily based on monthly spot-market prices.

SDG&E has natural gas transportation contracts with various interstate pipelines that expire on various dates between 2007 and 2023. SDG&E currently purchases natural gas on a spot basis from Canada, the U.S. Rockies 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 continues to reconfigure its pipeline capacity portfolio 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 average spot price of natural gas at the California/Arizona border was $6.15 per million British thermal units (mmbtu) in 2006 ($6.74 per mmbtu in December 2006), compared with $7.62 per mmbtu in 2005 and $5.57 per mmbtu in 2004. The company's weighted average cost (including transportation charges) per mmbtu of natural gas was $6.94 in 2006, $8.67 in 2005 and $6.11 in 2004.

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 and Canada. 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 SDG&E’s 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 8,000 and 12,000 new customer meters in 2006 and 2005, respectively, representing growth rates of 1.0 percent and 1.5 percent in 2006 and 2005, respectively. The slower growth in 2006 reflects a slowdown in the housing market. The company expects that its growth rate for 2007 will approximate that of 2006.

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, 2006, the company had 1.4 million customer meters consisting of 1,202,000 residential, 144,000 commercial, 500 industrial, 2,000 street and highway lighting, and 5,800 direct access. The company's service area covers 4,100 square miles. The company added 17,000 new customer meters in 2006 and 20,000 in 2005, representing growth rates of 1.3 percent and 1.5 percent, respectively. The company expects that its growth rate for 2007 will approximate that of 2006.

Resource Planning and Power Procurement

SDG&E's resource planning, power procurement and related regulatory matters are discussed 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 its various suppliers, its Palomar and Miramar generating plants and its 20-percent ownership interest in SONGS, the supply of electric power available to SDG&E as of December 31, 2006, is as follows:

Supplier	Source	Expiration date	Megawatts
PURCHASED-POWER CONTRACTS:			
DWR ** -allocated contracts:			
Williams Energy Marketing & Trading	Natural gas	2007 to 2010	700*
Sunrise Power Co. LLC	Natural gas	2012	575
Other (5 contracts)	Natural gas / wind	2011 to 2013	264
Total			1,539
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 (18 contracts)	Cogeneration	2009 and thereafter	56
Total			258
Other contracts with renewable sources:			
Oasis Power Partners	Wind	2019	60
Kumeyaay	Wind	2025	50
AES Delano	Bio-mass	2007	49
PPM Energy	Wind	2018	25
WTE / FPL	Wind	2019	17
Other (6 contracts)	Bio-gas	2007 to 2014	24
Total			225
Other long-term contracts:			
Portland General Electric (PGE)	Coal	2013	89
Celerity	Natural Gas	2016	5
Total contracted			2,116
GENERATION:			
Palomar	Natural Gas		550
SONGS	Nuclear		430
Miramar	Natural Gas		45
Total generation			1,025
TOTAL CONTRACTED AND GENERATION			3,141

* Effective January 1, 2007, after 1,206 megawatts were reallocated to Southern California Edison (Edison) by the CPUC, as described in Note 9 of the notes to Consolidated Financial Statements.

** California's 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 city of Riverside owns 1.79 percent of Units 2 and 3, and Edison, the operator of SONGS owns the remaining interests. The city of Anaheim sold its 3.16 percent interest in SONGS Units 2 and 3 to Edison effective December 28, 2006.

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 has fully recovered its SONGS capital investment through December 31, 2003 and earns a return only on subsequent additions, including the company's share of costs associated with planned steam generator replacements.

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 2012. The availability and the cost of the various components of the nuclear fuel cycle for SDG&E's 20-percent ownership interest in SONGS 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 preapproved by the FERC.

Transmission Arrangements

The Pacific Intertie, consisting of AC and DC transmission lines, connects the Northwest U.S. with SDG&E, Pacific Gas & Electric, Edison and others under an agreement. 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 2,200 MW.

Subject to the FERC's approval and any litigation concerning term, the Pacific Intertie agreement will expire no earlier than July 31, 2007. SDG&E is currently evaluating its participation in the agreement, and has not yet determined whether or not to propose an extension of the agreement.

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 1,163 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 $1.3 billion, of which SDG&E's participation is expected to be $1.0 billion. The project, subject to timely regulatory approval and permitting, is planned to be in service in 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 9 of the notes to Consolidated Financial Statements herein.

ENVIRONMENTAL MATTERS

Discussions about environmental issues affecting the company are included in Notes 9 and 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. Rate 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, 2006, 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 $0.3 million, of which 90 percent is authorized to be recovered through the Hazardous Waste Collaborative mechanism. This estimated cost excludes remediation costs of $8.9 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. In 2006, the CPUC 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 an 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 $35 million, of which $18 million had been incurred at December 31, 2006, and $17 million is accrued for the remaining costs through 2050. In May 2006, the CPUC adopted a decision in Edison's 2006 General Rate Case, in which decision SDG&E is no longer subject to a 50-percent disallowance of cost recovery going forward.

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 program is administered by the CEC. SDG&E funding for the program was $1 million for each of 2006 and 2005.

SDG&E continues to fund the California Public Interest Energy Research (PIER) Program for electric research. SDG&E's funding level for the PIER program was $6 million for each of 2006, 2005 and 2004.

Employees of Registrant

As of December 31, 2006, the company had 4,758 employees, compared to 4,505 at December 31, 2005.

Labor Relations

Field, technical and some clerical employees at SDG&E are represented by Local 465 International Brotherhood of Electrical Workers. The collective bargaining agreement for field, technical and some clerical employees at SDG&E covering wages, hours and working conditions is in effect through August 31, 2008. For these same employees, the agreements covering health and welfare benefits and pension benefits are in effect through December 31, 2007 and December 4, 2009, respectively.

ITEM 2. PROPERTIES

Electric Properties

SDG&E owns two natural gas-fired power plants: a 550-MW electric generation facility (the Palomar generation facility) located in Escondido, California, and a 45-MW electric generation facility (the Miramar generation facility) located in San Diego, California. SDG&E's interest in SONGS is described in "Electric Resources" herein.

At December 31, 2006, 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 1,879 miles of transmission lines and 21,887 miles of distribution lines. Periodically, various areas of the service territory require expansion to accommodate customer growth.

Natural Gas Properties

At December 31, 2006, 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, 165 miles of transmission pipelines, 8,263 miles of distribution mains, and 6,266 miles of service lines.

Other Properties

SDG&E occupies an office complex in San Diego pursuant to two separate operating leases. One lease ends in 2007, with two five-year renewal options. The second lease ends in 2017, and has four five-year renewal options.

The company owns or leases other land, easements, rights of way, 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 in "Management's Discussion and Analysis of Financial Condition and Results of Operations," neither the company nor its subsidiary is party to, nor is their property the subject of, any material pending legal proceedings.

The County of San Diego filed and then withdrew litigation against Sempra Energy and SDG&E that sought unspecified civil penalties for alleged violations of environmental standards applicable to the abatement, handling and disposal of asbestos-containing materials during the 2001 demolition of a natural gas storage facility. In addition, in November 2006, a federal court dismissed all charges against SDG&E and two employees in a federal criminal indictment charging them with having violated these standards and for related charges of conspiracy and having made false statements to governmental authorities. On February 12, 2007, the court granted the federal government's motion for reconsideration with respect to the false statement count and the matter will proceed to trial in 2007.

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 Comprehensive Income and Changes in Shareholders' Equity" set forth in Item 8 of the 2006 Annual Report to Shareholders herein.

Dividend Restrictions

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. Additional information regarding these restrictions is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Capital Resources and Liquidity--Dividends."

ITEM 6. SELECTED FINANCIAL DATA

	At December 31, or for the years then ended				
(Dollars in millions)	2006	2005	2004	2003	2002
Income Statement Data:					
Operating revenues	$ 2,785	$ 2,512	$ 2,274	$ 2,308	$ 1,725
Operating income	$ 477	$ 393	$ 393	$ 515	$ 349
Dividends on preferred stock	$ 5	$ 5	$ 5	$ 6	$ 6
Earnings applicable to common shares	$ 237	$ 262	$ 208	$ 334	$ 203
Balance Sheet Data:					
Total assets	$ 7,795	$ 7,492	$ 6,834	$ 6,461	$ 6,285
Long-term debt	$ 1,638	$ 1,455	$ 1,022	$ 1,087	$ 1,153
Short-term debt (a)	$ 138	$ 66	$ 66	$ 66	$ 66
Preferred stock subject to mandatory redemption (b)	$ 17	$ 19	$ 21	$ 24	$ 25
Shareholders' equity	$ 1,994	$ 1,562	$ 1,376	$ 1,343	$ 1,223

(a) Includes long-term debt due within one year.

(b) At December 31, 2006 and 2005, $14 million and $16 million, respectively, was included in Deferred Credits and Other Liabilities on the Consolidated Balance Sheets. $3 million was included in Other Current Liabilities at both dates.

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 2006 Annual Report includes management's discussion and analysis of operating results from 2004 through 2006, 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 Palomar and Miramar generating facilities and its 20-percent ownership interest in the San Onofre Nuclear Generating Station (SONGS), through 1.4 million meters in San Diego County and an adjacent portion of southern Orange County, California. It also purchases and distributes natural gas through 830,000 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 Sempra Utilities."

RESULTS OF OPERATIONS

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

(Dollars in millions)	
2006	$ 242
2005	$ 267
2004	$ 213
2003	$ 340
2002	$ 209

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 2006, 2005 and 2004. The numbers in parentheses are the page numbers where each 2006 item is discussed.

	Net Income			Operating Income		
(Dollars in millions)	2006	2005	2004	2006	2005	2004
Reported amounts	$ 242	$ 267	$ 213	$ 477	$ 393	$ 393
Unusual items:						
Other regulatory matters (23)	(25)	(23)	(21)	(39)	(33)	(25)
Resolution of prior years' income tax issues (23)	2	(60)	(12)	--	--	--
California energy crisis litigation (73)	(1)	28	11	(2)	47	19
DSM[1] awards settlement	--	(22)	--	--	(35)	--
South Bay charitable contribution deduction	--	(23)	--	--	(23)	--
	$ 218	$ 167	$ 191	$ 436	$ 349	$ 387

[1] Demand side management (DSM)

The company is subject to regulation by 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 $344 million (19%) to $2.1 billion in 2006, and the cost of electric fuel and purchased power increased by $97 million (16%) to $721 million in 2006. The increase in revenue was due to $206 million of increased authorized distribution, generation and transmission base margins, $60 million higher revenues for recoverable expenses, which are fully offset in other operating expenses, and the $20 million favorable resolution of a prior year cost recovery issue. The increases were offset by a $28 million DSM awards settlement in 2005 and $23 million from the 2005 Internal Revenue Service (IRS) decision relating to the sale of SDG&E's former South Bay power plant. In addition, electric revenues and costs increased due to the commencement of commercial operations of the Palomar generating plant in 2006, which contributed $112 million to both 2006 revenues and costs.

Electric revenues increased by $125 million (7%) to $1.8 billion in 2005 compared to 2004, and the cost of electric fuel and purchased power increased by $48 million (8%) to $624 million in 2005 compared to 2004. The increase in revenue was due to $41 million of higher revenues for recoverable expenses, the DSM awards settlement in 2005 and the 2005 IRS decision, as discussed above. In addition, revenues and costs increased $48 million due to higher purchased power costs.

Natural Gas Revenue and Cost of Natural Gas. Natural gas revenues decreased by $71 million (10%) to $638 million in 2006, and the cost of natural gas decreased by $76 million (17%) to $380 million in 2006. The decreases in 2006 were due to lower overall average costs of natural gas, which are passed on to customers, offset by higher volumes. The company's weighted average cost (including transportation charges) per million British thermal units (mmbtu) of natural gas was $6.94 in 2006, $8.67 in 2005 and $6.11 in 2004.

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 compared to 2004. The increases in 2005 were due to higher natural gas prices, which are passed on to customers, offset by a decrease in volume. In addition, natural gas revenues increased due to $7 million in DSM awards in 2005. Performance awards are discussed in Note 10 of the notes to Consolidated Financial Statements.

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 Performance-Based Regulation (PBR) mechanism provides an incentive mechanism by measuring SDG&E's procurement of natural gas against a benchmark price comprised of monthly natural gas indices, resulting in shareholder rewards for costs achieved below the benchmark and shareholder penalties when costs exceed the benchmark. Further discussion is provided in Notes 1 and 10 of the notes to Consolidated Financial Statements.

The tables below summarize the electric and natural gas volumes and revenues by customer class for the years ended December 31, 2006, 2005 and 2004.

Electric Distribution and Transmission
(Volumes in millions of kilowatt-hours, dollars in millions)

	2006		2005		2004	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
Residential	7,501	$ 910	7,075	$ 738	7,038	$ 692
Commercial	6,983	723	6,674	654	6,592	644
Industrial	2,261	181	2,159	142	2,084	134
Direct access	3,390	133	3,213	114	3,441	105
Street and highway lighting	102	10	93	11	97	11
	20,237	1,957	19,214	1,659	19,252	1,586
Balancing accounts and other		190		144		92
Total		$ 2,147		$ 1,803		$ 1,678

Although commodity costs associated with long-term contracts allocated to SDG&E from the Department of Water Resources (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
2006:						
Residential	31	$ 397	--	$ --	31	$ 397
Commercial and industrial	17	169	5	7	22	176
Electric generation plants	--	2	65	44	65	46
	48	$ 568	70	$ 51	118	619
Balancing accounts and other						19
Total						$ 638
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

Other Operating Expenses. Other operating expenses were $774 million, $603 million and $574 million in 2006, 2005 and 2004, respectively. The increase in 2006 was due to $72 million higher recoverable expenses, $33 million 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, $24 million higher SONGS operating costs and a $42 million increase in various other operational costs. The increase in 2005 compared to 2004 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 favorable settlement with the ISO noted previously.

Litigation Expenses. Litigation expenses were $3 million, $52 million and $19 million for 2006, 2005 and 2004, respectively. The higher amount in 2005 was primarily due to increases 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.

Interest Income. Interest income was $6 million, $23 million and $25 million in 2006, 2005 and 2004, respectively. The decrease in 2006 was primarily due to $12 million lower interest as a result of income tax audit settlements in 2005.

Interest Expense. Interest expense was $97 million, $74 million and $68 million in 2006, 2005 and 2004, respectively. The increase in 2006 was primarily due to increased borrowings to finance the purchase of the Palomar generating plant, and interest expense related to the accretion of the California energy crisis litigation settlement liability.

Income Taxes. Income tax expense was $152 million, $89 million and $148 million in 2006, 2005 and 2004, respectively. The corresponding effective income tax rates were 39 percent, 25 percent and 41 percent. The increase in 2006 expense was due to the higher effective tax rate and higher pretax income. The increase in the effective tax rate in 2006 was due primarily to a $60 million favorable resolution of prior years' income tax issues in 2005, compared to $2 million unfavorable in 2006 and $12 million favorable in 2004.

Net Income. SDG&E recorded net income of $242 million, $267 million and $213 million in 2006, 2005 and 2004, respectively. The decrease in 2006 was primarily due to $60 million associated with the favorable resolution of prior years' income tax issues in 2005, the $23 million recovery of costs in 2005 associated with an IRS decision relating to the sale of the South Bay power plant and $22 million related to a DSM awards settlement in 2005. These items were offset by a $42 million increase in earnings from electric generation activities including the commencement of commercial operation of the Palomar generating plant in 2006, $28 million due to the litigation expense in 2005 related to the California energy crisis matter and a $13 million increase in earnings due to lower income tax expense primarily resulting from a lower effective tax rate in 2006 (excluding the effect of the resolution of prior years' income tax issues in 2005). Also, the resolution of regulatory items increased 2006 net income by $25 million as compared to $23 million in 2005. The 2006 regulatory items include a $13 million resolution of prior year cost recovery issue; $8 million due to the CPUC authorization for retroactive recovery on SONGS revenues related to a computational error in the 2004 Cost of Service; and $4 million due to FERC approval to recover prior year ISO charges in 2006. The 2005 regulatory item of $23 million resulted from FERC approval to recover prior year ISO charges in 2005 (as discussed further in Note 10 of the notes to Consolidated Financial Statements).

The increase in 2005 compared to 2004 was due primarily to the favorable settlement with the ISO, the DSM awards settlement, favorable resolution of income tax issues, and the 2005 IRS decision discussed above, offset by a $17 million increase in after-tax California energy crisis litigation expense, the favorable impact of $21 million from the resolution of the 2004 Cost of Service proceeding and $19 million lower electric transmission and distribution authorized base margins and higher operational costs in 2005.

CAPITAL RESOURCES AND LIQUIDITY

The company's utility operations generally are the major source of liquidity. In addition, cash 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, 2006, there was $9 million in unrestricted cash and $228 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.

In connection with the purchase of the Palomar generating plant in the first quarter of 2006, the company received a $200 million capital contribution from Sempra Energy, the company's dividends to Sempra Energy have been suspended to increase SDG&E's equity, and the level of future common dividends may be affected in order to maintain SDG&E's authorized capital structure during periods of increased capital expenditures.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $397 million, $338 million and $435 million for 2006, 2005 and 2004, respectively.

Cash provided by operating activities in 2006 increased by $59 million (17%) to $397 million. The change was primarily due to a $138 million decrease in the reduction of overcollected regulatory balancing accounts in 2006 as compared to 2005 and a $95 million decrease in accounts receivable, offset by a $53 million decrease in other liabilities, a $50 million decrease in current liabilities, a $37 million increase in interest receivable and a $29 million increase in inventories.

The decrease in 2005 compared to 2004 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 and a $57 million reduction in interest receivable.

The company made pension plan and other postretirement benefit plan contributions of $30 million and $12 million, respectively, during 2006, $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 $1.1 billion, $458 million and $289 million for 2006, 2005 and 2004, respectively.

Cash used in investing activities in 2006 increased by $609 million (133%) to $1.1 billion primarily due to a $606 million increase in capital expenditures in 2006, including the purchase of the Palomar generating plant.

The increase in cash used in investing activities in 2005 compared to 2004 was due to a $50 million increase in capital expenditures in 2005 and a $122 million decrease in loans to affiliate in 2004.

Future Capital Expenditures for Utility Plant

Significant capital expenditures and investments in 2007 are expected to include $600 million 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 and security issuances.

Over the next five years, the company expects to make capital expenditures of $4.1 billion at a rate ranging from $600 million to $1.1 billion per year.

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 of southern

California. The proposed line, called the Sunrise Powerlink, would be capable of providing electricity to 650,000 homes and is estimated to cost $1.3 billion, of which SDG&E's participation is expected to be $1.0 billion. Additional information on the Sunrise Powerlink is provided in Note 9 of the notes to Consolidated Financial Statements.

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.

SDG&E's involvement with the Otay Mesa power plant and its potential involvement with the El Dorado power plant are 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 $443 million, $347 million and $(285) million for 2006, 2005 and 2004, respectively.

Cash provided by financing activities in 2006 increased by $96 million (28%) to $443 million, primarily due to a $200 million capital contribution from Sempra Energy and a $72 million increase in short-term debt, offset by a $161 million increase in payments on long-term debt and an $89 million decrease in issuances of long-term debt. In addition, the company did not pay any common dividends in 2006 as compared to $75 million of common dividends paid in 2005.

The 2005 increase in cash provided by financing activities compared to 2004 was due to the $500 million issuances of first mortgage bonds in 2005 and a $130 million decrease in common dividends paid in 2005.

Long-Term and Short-Term Debt

In September 2006, the company issued $161 million of variable-rate first mortgage bonds, maturing in 2018, and applied the proceeds in November 2006 to retire an identical amount of first mortgage bonds and related tax-exempt industrial development bonds of a similar weighted-average maturity. The bonds will 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 have been loaned to the company and will be repaid with payments on the first mortgage bonds.

In June 2006, the company publicly offered and sold $250 million of 6 percent first mortgage bonds, maturing in 2026.

Payments on long-term debt in 2006 included $161 million of the company's first mortgage bonds and $66 million of rate-reduction bonds.

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

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

Payments on long-term debt in 2005 were $66 million related to the company's 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-to-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.

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

Dividends

Common dividends paid to Sempra Energy were $75 million in 2005 and $205 million in 2004. The company did not pay any common dividends to Sempra Energy in 2006 to preserve cash to partially fund the purchase of the Palomar generating plant in the first quarter of 2006.

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, 2006, no amount was available from SDG&E.

Capitalization

Total capitalization, including all debt other than the rate-reduction bonds (which are non-recourse to the company), at December 31, 2006 was $3.7 billion. The debt-to-capitalization ratio was 46 percent at December 31, 2006. Significant changes affecting capitalization during 2006 included long-term borrowings and repayments, short-term borrowings, comprehensive income and dividends. Additional discussion related to the significant changes is provided in Note 2 of the notes to Consolidated Financial Statements and "Results of Operations" above.

Commitments

The following is a summary of the company's principal contractual commitments at December 31, 2006. 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)	2007	2008 and 2009	2010 and 2011	Thereafter	Total
Short-term debt	$ 72	$ --	$ --	$ --	$ 72
Long-term debt	66	--	--	1,638	1,704
Interest on debt (1)	83	161	163	1,078	1,485
Operating leases	20	29	23	43	115
Litigation reserves	26	12	12	19	69
Purchased-power contracts	289	650	613	2,468	4,020
Natural gas contracts	41	32	20	105	198
Preferred stock subject to mandatory redemption	3	14	--	--	17
Construction commitments	18	16	5	12	51
SONGS decommissioning	15	5	--	334	354
Other asset retirement obligations	6	4	5	114	129
Pension and postretirement benefit obligations (2)	61	131	143	295	630
Environmental commitments	9	13	--	4	26
Totals	$ 709	$ 1,067	$ 984	$ 6,110	$ 8,870

(1) Expected interest payments were calculated using the stated interest rate for fixed rate obligations, including floating-to-fixed interest rate swaps. Expected interest payments were calculated based on forward rates in effect at December 31, 2006 for variable rate obligations.
(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 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 2006. As of January 31, 2007, company credit ratings were 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, 2007, the company has a stable ratings outlook 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 capital projects, 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 regulation 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 subject to certain limitations imposed by company policy and 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 on a substantially concurrent basis.

Revenue recognition is discussed in Note 1 of the notes to Consolidated Financial Statements 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, 2006 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 intrastate transportation and storage activity. However, the company may, at times, be exposed to market risk as a result of SDG&E's natural gas PBR and electric procurement activities, which is discussed in 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, 2006, 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. Subject to regulatory constraints, interest-rate swaps may be used to adjust interest-rate exposures. The company periodically enters into interest-rate swap agreements to moderate its exposure to interest-rate changes and to lower its overall costs of borrowing.

At December 31, 2006, the company had $1.5 billion of fixed-rate, long-term debt and $161 million of variable-rate, long-term 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, 2006, the company’s fixed-rate, long-term debt, after the effects of interest-rate swaps, had a one-year VaR of $152 million and variable-rate, long-term debt, after the effects of interest-rate swaps, did not have a significant one-year VaR.

At December 31, 2006, 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 in the United States of America and the regulations of the Securities and Exchange Commission, are the following:

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Contingencies		
Statement of Financial Accounting Standards (SFAS) 5, *Accounting for Contingencies*, establishes the amounts and timing of when the company provides for contingent losses. The company continuously assesses potential loss contingencies for litigation claims, environmental remediation and other events.	The company accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain outcomes. For loss contingencies, the loss is accrued if (1) information is available that indicates it is probable that the loss has been incurred, given the likelihood of uncertain future events and (2) the amounts of the loss can be reasonably estimated. SFAS 5 does not permit the accrual of contingencies that might result in gains.	Details of the company's issues in this area are discussed in Note 11 of the notes to Consolidated Financial Statements.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Regulatory Accounting SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, has a significant effect on the way the Sempra Utilities record assets and liabilities, and the related revenues and expenses that would not be recorded absent the principles contained in SFAS 71.	The company records a regulatory asset if it is probable that, through the ratemaking process, the utility will recover that asset from customers. Similarly, the company records regulatory liabilities for amounts recovered in rates in advance of the expenditure. The company reviews probabilities associated with regulatory balances whenever new events occur, such as changes in the regulatory environment or the utility's competitive position, issuance of a regulatory commission order or passage of new legislation. To the extent that circumstances associated with regulatory balances change, the regulatory balances could be adjusted.	Details of the company's regulatory assets and liabilities are discussed in Note 1 of the notes to Consolidated Financial Statements.
Income Taxes SFAS 109, *Accounting for Income Taxes*, governs the way the company provides for income taxes.	The company's income tax expense and related balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve judgments and estimates of the timing and probability of recognition of income and deductions by taxing authorities. 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. The likelihood of deferred tax recovery is based on analyses of the deferred tax assets and the company's expectation of future taxable income, based on its strategic planning.	Actual income taxes could vary from estimated amounts due to the future impacts of various items including changes in tax laws, the company's financial condition in future periods, and the resolution of various income tax issues between the company and the various taxing authorities. Details of the company's issues in this area are discussed in Note 4 of the notes to Consolidated Financial Statements.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Derivatives SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, and related Emerging Issues Task Force Issues govern the accounting requirements for derivatives.	The company values derivative instruments at fair value on the balance sheet. Depending on the purpose for the contract and the applicability of hedge accounting, the impact of instruments may be offset in earnings, on the balance sheet, or in other comprehensive income. The company also utilizes normal purchase or sale accounting for certain contracts.	The application of hedge accounting to certain derivatives and the normal purchase or sale election is made on a contract-by-contract basis. Utilizing hedge accounting or the normal purchase or sale election in a different manner could materially impact reported results. The effects of derivatives' accounting have a significant impact on the balance sheet of the company but have no significant effect on its results of operations because of the principles contained in SFAS 71 and the application of the normal purchase or sale election. Details of the company's financial instruments are discussed in Note 7 of the notes to Consolidated Financial Statements.
Impairments of Long-Lived Assets SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires that long-lived assets be evaluated as necessary for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable or the assets meet the held-for-sale criteria under SFAS 144.	The company uses the best information available to estimate fair value of its long-lived assets and may use more than one source. Judgment is exercised to estimate the future cash flows, the useful lives of long-lived assets and to determine management's intent to use the assets. Management's intent to use or dispose of assets is subject to re-evaluation and can change over time.	In connection with the evaluation of long-lived assets in accordance with the requirements of SFAS 144, the fair value of the asset can vary if different estimates and assumptions were used in the applied valuation techniques.

Description	Assumptions & Approach Utilized	Effect if Different Assumptions Used
Defined Benefit Plans The company has funded and unfunded noncontributory defined benefit plans that together cover substantially all of its employees. The company also has other postretirement benefit plans covering substantially all of its employees. The company accounts for its pension and other postretirement benefit plans under SFAS 87, *Employers' Accounting for Pensions*, and SFAS 106, *Employers' Accounting for Postretirement Benefits Other than Pensions*, respectively, and under SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).*	The measurement of the company's pension and postretirement obligations, and costs and liabilities is dependent on a variety of assumptions used by the company. The critical assumptions used in developing the required estimates include the following key factors: discount rate, expected return on plan assets, health care cost trend rates, mortality rates, rate of compensation increases and payout elections (lump sum or annuity). 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.	The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter participant life spans, or more or fewer lump sum versus annuity payout elections made by plan participants. However, these differences have minimal impact on the company's net income due to rate recovery of most benefit plan costs. Additional discussion of pension plan assumptions is included in Note 5 of the notes to Consolidated Financial Statements.

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 "Results of Operations."

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had or may have a significant effect on the company's financial statements are described in Note 1 of the notes to Consolidated Financial Statements.

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 RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management is responsible for the preparation of the company's consolidated financial statements and related information appearing in this report. Management believes that the consolidated financial statements fairly present the form and substance of transactions and that the financial statements reasonably present the company's financial position and results of operations in conformity with accounting principles generally accepted in the United States of America. Management also has included in the company's financial statements amounts that are based on estimates and judgments, which it believes are reasonable under the circumstances.

The board of directors of Sempra Energy, the company's parent company, has an Audit Committee composed of five non-management directors. The committee meets periodically with financial management and the internal auditors to review accounting, control, auditing and financial reporting matters.

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, 2006. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 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 management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that San Diego Gas & Electric Company and subsidiary (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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, 2006, 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, 2006, 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, 2006 of the Company and our report dated February 21, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of two new accounting standards.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 21, 2007

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, 2006 and 2005, and the related statements of consolidated income, comprehensive income and changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 San Diego Gas & Electric Company and subsidiary as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board ("FASB") Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, effective December 31, 2006, and FASB 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, 2006, 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, 2007 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, 2007

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

(Dollars in millions)	Years ended December 31, 2006	2005	2004
Operating revenues			
Electric	$ 2,147	$ 1,803	$ 1,678
Natural gas	638	709	596
Total operating revenues	2,785	2,512	2,274
Operating expenses			
Cost of electric fuel and purchased power	721	624	576
Cost of natural gas	380	456	347
Other operating expenses	774	603	574
Depreciation and amortization	291	264	259
Franchise fees and other taxes	140	119	113
Litigation expense	3	52	19
Gain on sale of assets	(1)	(1)	(1)
Impairment losses (adjustments)	--	2	(6)
Total operating expenses	2,308	2,119	1,881
Operating income	477	393	393
Other income, net	8	14	11
Interest income	6	23	25
Interest expense	(97)	(74)	(68)
Income before income taxes	394	356	361
Income tax expense	152	89	148
Net income	242	267	213
Preferred dividend requirements	5	5	5
Earnings applicable to common shares	$ 237	$ 262	$ 208

See notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9	$ 236
Accounts receivable – trade	206	188
Accounts receivable – other	26	83
Interest receivable	15	17
Due from unconsolidated affiliates	24	32
Income taxes receivable	25	--
Deferred income taxes	41	7
Inventories	97	78
Regulatory assets arising from fixed-price contracts and other derivatives	83	76
Other regulatory assets	69	91
Other	71	39
Total current assets	666	847
Other assets:		
Due from unconsolidated affiliate	5	--
Deferred taxes recoverable in rates	318	294
Regulatory assets arising from fixed-price contracts and other derivatives	353	398
Regulatory assets arising from pensions and other postretirement benefit obligations	220	165
Other regulatory assets	59	111
Nuclear decommissioning trusts	702	638
Sundry	72	66
Total other assets	1,729	1,672
Property, plant and equipment:		
Property, plant and equipment	7,495	6,931
Less accumulated depreciation and amortization	(2,095)	(1,958)
Property, plant and equipment, net	5,400	4,973
Total assets	$ 7,795	$ 7,492

See notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

(Dollars in millions)	December 31, 2006	December 31, 2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Short-term debt	$ 72	$ --
Accounts payable	273	243
Due to unconsolidated affiliates	5	441
Income taxes payable	--	6
Regulatory balancing accounts, net	165	179
Fixed-price contracts and other derivatives	83	76
Customer deposits	47	52
Current portion of long-term debt	66	66
Other	290	282
Total current liabilities	1,001	1,345
Long-term debt	1,638	1,455
Deferred credits and other liabilities:		
Customer advances for construction	38	39
Pension and other postretirement benefit obligations, net of plan assets	249	194
Deferred income taxes	520	591
Deferred investment tax credits	31	34
Regulatory liabilities arising from removal obligations	1,311	1,216
Asset retirement obligations	462	444
Fixed-price contracts and other derivatives	353	398
Mandatorily redeemable preferred securities	14	16
Deferred credits and other	184	198
Total deferred credits and other liabilities	3,162	3,130
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Preferred stock not subject to mandatory redemption	79	79
Common stock (255 million shares authorized; 117 million shares outstanding; no par value)	1,138	938
Retained earnings	796	559
Accumulated other comprehensive income (loss)	(19)	(14)
Total shareholders' equity	1,994	1,562
Total liabilities and shareholders' equity	$ 7,795	$ 7,492

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, 2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 242	$ 267	$ 213
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	291	264	259
Deferred income taxes and investment tax credits	(130)	37	--
Non-cash rate reduction bond expense	60	68	75
Other	3	(3)	(7)
Changes in other assets	9	13	(53)
Changes in other liabilities	(16)	37	(25)
Changes in working capital components:			
Accounts receivable	39	(56)	(24)
Interest receivable	2	39	(18)
Due to/from affiliates, net	(12)	(1)	13
Inventories	(19)	10	(27)
Other current assets	(19)	(16)	(1)
Income taxes	(32)	(231)	15
Accounts payable	9	28	6
Regulatory balancing accounts	(14)	(152)	(15)
Other current liabilities	(16)	34	24
Net cash provided by operating activities	397	338	435
CASH FLOWS FROM INVESTING ACTIVITIES			
Expenditures for property, plant and equipment	(1,070)	(464)	(414)
Purchases of nuclear decommissioning trust assets	(481)	(230)	(244)
Proceeds from sales by nuclear decommissioning trust	484	234	247
Decrease (increase) in loans to affiliates, net	(1)	1	122
Proceeds from sale of assets	1	1	--
Net cash used in investing activities	(1,067)	(458)	(289)
CASH FLOWS FROM FINANCING ACTIVITIES			
Capital contribution	200	--	--
Common dividends paid	--	(75)	(205)
Preferred dividends paid	(5)	(5)	(5)
Redemptions of preferred stock	(3)	(3)	(3)
Issuances of long-term debt	411	500	251
Payments on long-term debt	(227)	(66)	(317)
Increase in short-term debt, net	72	--	--
Other	(5)	(4)	(6)
Net cash provided by (used in) financing activities	443	347	(285)
Increase (decrease) in cash and cash equivalents	(227)	227	(139)
Cash and cash equivalents, January 1	236	9	148
Cash and cash equivalents, December 31	$ 9	$ 236	$ 9

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, 2006	2005	2004
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Interest payments, net of amounts capitalized	$ 91	$ 66	$ 63
Income tax payments, net of refunds	$ 313	$ 291	$ 129
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING ACTIVITY			
Increase (decrease) in accounts payable from investments in property, plant and equipment	$ 21	$ 15	$ (28)

See notes to Consolidated Financial Statements

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME AND CHANGES IN SHAREHOLDERS' EQUITY
Years ended December 31, 2006, 2005 and 2004

(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, 2003		$ 79	$ 938	$ 369	$ (43)	$ 1,343
Net income	$ 213			213		213
Pension adjustment	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
Pension adjustment	(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
Net income	$ 242			242		242
Pension adjustment	(2)				(2)	(2)
Comprehensive income	$ 240					
Adjustment to initially apply FASB Statement No. 158 (Notes 1 and 5)					(3)	(3)
Preferred stock dividends declared				(5)		(5)
Capital contribution			200			200
Balance at December 31, 2006		$ 79	$ 1,138	$ 796	$ (19)	$ 1,994

See notes to Consolidated Financial Statements.

SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
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. 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. All material intercompany accounts and transactions have been eliminated.

Sempra Energy also indirectly owns all of the common stock of Southern California Gas Company (SoCalGas). SDG&E and SoCalGas are collectively referred to herein as the Sempra Utilities.

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 the cost is reasonable and probably less than if the company had to provide those services itself. 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 ultimately may differ significantly from those estimates.

Basis of Presentation

The company's Statements of Consolidated Income have been converted from a utility format, where only regulated cost-of-service items, including income taxes on operating income, were reflected in Operating Income, to a commercial format, where nonutility items are reflected as components of Operating Income. Also, in the Consolidated Balance Sheets under the commercial format, nonutility property is included in Property, Plant and Equipment.

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).

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* (SFAS 71), 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. 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, 2006, 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 from forecasted amounts approved by the CPUC in establishing rates 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)	2006	2005
Fixed-price contracts and other derivatives	$ 429	$ 473
Recapture of temporary rate reduction*	56	116
Deferred taxes recoverable in rates	318	294
Unamortized loss on reacquired debt, net	38	42
Pension and other postretirement benefit obligations	220	165
Removal obligations**	(1,311)	(1,216)
Environmental costs	16	16
Other	18	29
Total	$ (216)	$ (81)

* 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 "Asset Retirement Obligations."

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

(Dollars in millions)		2006		2005
Current regulatory assets	$	152	$	167
Noncurrent regulatory assets		950		968
Current regulatory liabilities*		(7)		--
Noncurrent regulatory liabilities		(1,311)		(1,216)
Total	$	(216)	$	(81)

* Included in Other Current Liabilities.

Regulatory assets arising from fixed-price contracts and other derivatives are offset by corresponding liabilities arising from purchased power and natural gas transportation contracts. The regulatory asset is reduced as payments are made for services under these contracts. Deferred taxes recoverable in rates are based on current regulatory ratemaking and income tax laws. SDG&E expects to recover net regulatory assets related to deferred income taxes over the lives of the assets that give rise to the accumulated deferred income taxes. The regulatory asset related to the recapture of a temporary rate reduction is amortized simultaneously with the amortization of the related rate reduction bond liability and is expected to be recovered by the end of 2007. The regulatory assets related to unamortized losses on reacquired debt are being recovered over the remaining original amortization periods of the loss on reacquired debt over periods ranging from 3 months to 21 years. Regulatory assets related to environmental costs represent the portion of the company's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. Regulatory assets related to pension and other postretirement benefit obligations are offset by corresponding liabilities and are being recovered in rates based on the current regulatory framework.

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

Cash and Cash Equivalents

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

Collection Allowances

The allowance for doubtful accounts was $2 million, $2 million and $2 million at December 31, 2006, 2005 and 2004, respectively. The company recorded provisions for doubtful accounts of $2 million, $3 million and $3 million in 2006, 2005 and 2004, respectively. The company wrote off doubtful accounts of $2 million, $3 million, and $3 million in 2006, 2005 and 2004, respectively.

Inventories

At December 31, 2006, inventory shown on the Consolidated Balance Sheets included natural gas of $43 million, and materials and supplies of $54 million. The corresponding balances at December 31, 2005 were $30 million and $48 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* (SFAS 109), 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 are recognized in income as earned. The company follows certain provisions of SFAS 109 that require 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

Property, plant and equipment 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), as discussed below. The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

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

	Property, Plant and Equipment at December 31,		Depreciation rates for the years ended December 31,		
(Dollars in billions)	2006	2005	2006	2005	2004
Natural gas operations	$ 1.1	$ 1.1	3.42%	3.42%	3.42%
Electric distribution	3.7	3.5	4.13%	4.13%	4.11%
Electric transmission	1.2	1.1	3.07%	3.05%	3.06%
Other electric	1.2	0.6	8.70%	9.75%	11.33%
Construction work in progress	0.3	0.6	NA	NA	NA
Total	$ 7.5	$ 6.9			

Accumulated depreciation and decommissioning of natural gas and electric utility plant in service were $0.4 billion and $1.7 billion, respectively, at December 31, 2006, and were $0.4 billion and $1.6 billion, respectively, at December 31, 2005. Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC.

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 expense and partly as a component of Other Income, Net in the Statements of Consolidated Income. AFUDC amounted to $15 million, $12 million and $12 million for 2006, 2005 and 2004, respectively.

Asset Retirement Obligations

The company accounts for its tangible long-lived assets under SFAS 143, *Accounting for Asset Retirement Obligations* (SFAS 143), and FASB Interpretation Number (FIN) 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS 143* (FIN 47). SFAS 143 and FIN 47 require the company to record an asset retirement obligation for the present value of liabilities of future costs expected to be incurred when assets are retired from service, if the retirement process is legally required and if a reasonable estimate of fair value can be made. 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. Rate-regulated entities may recognize regulatory assets or liabilities as a result of the timing difference between the recognition of costs as recorded in accordance with SFAS 143 and FIN 47, and costs recovered through the rate-making process. Accordingly, a regulatory liability has been recorded to reflect that the company has collected the funds from customers more quickly than SFAS 143 and FIN 47 would accrete the retirement liability and depreciate the asset.

Upon the adoption of SFAS 143 and FIN 47, the company recognized asset retirement obligations related to fuel storage tanks, hazardous waste storage facilities, decommissioning of its nuclear power facilities, natural gas transportation and distribution, electric distribution, and electric transmission systems assets, and the site restoration of a former power plant.

The changes in the asset retirement obligations for the years ended December 31, 2006 and 2005 are as follows:

(Dollars in millions)	2006	2005
Balance as of January 1	$ 463*	$ 339
Adoption of FIN 47	--	116
Accretion expense	30	23
Payments	(12)	(15)
Revision to estimated cash flows	2	--
Balance as of December 31	$ 483*	$ 463*

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

Nuclear Decommissioning Liability

At December 31, 2006 and 2005, the company had asset retirement obligations of $354 million and $339 million, respectively, and related regulatory liabilities of $394 million and $346 million, respectively, related to nuclear decommissioning, in accordance with SFAS 143.

Legal Fees

Legal fees that are associated with a past event for which a liability has been recorded are accrued when it is probable that fees also will be incurred.

Comprehensive Income

Comprehensive income includes all changes in the equity of a business enterprise (except those resulting from investments by owners and distributions to owners), including amortization of net actuarial loss and prior service cost related to pension and other postretirement benefits plans and changes in minimum pension liability. The components of other comprehensive income, which consist of all these changes other than net income as shown on the Statements of Consolidated Income, are shown in the Statements of Consolidated Comprehensive Income and Changes in Shareholders' Equity.

The components of Accumulated Other Comprehensive Income (Loss), net of income taxes, at December 31, 2006 and 2005 are as follows:

(Dollars in millions)	2006	2005
Unamortized net actuarial loss, net of $14 income tax benefit	$ (20)	$ --
Unamortized prior service cost, net of $1 income tax	1	--
Minimum pension liability adjustments, net of $10 income tax benefit	--	(14)
Balance as of December 31	$ (19)	$ (14)

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 revenues include amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year. The company presents its operating revenues net of sales taxes.

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, 2006 and 2005, SDG&E had $24 million and $32 million, respectively, due from affiliates. These amounts are included in current assets as Due from Unconsolidated Affiliates.

SDG&E also has a promissory note due from Sempra Energy which bears a variable interest rate based on short-term commercial paper rates (5.21 percent at December 31, 2006). The balance of the note was $5 million at December 31, 2006 and is included in noncurrent assets as Due from Unconsolidated Affiliates.

Additionally, at December 31, 2006, SDG&E had $5 million due to affiliates, including $3 million to Sempra Energy. 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.

Capitalized Interest

SDG&E recorded $6 million, $4 million and $4 million of capitalized interest for 2006, 2005 and 2004, respectively, including the portion of AFUDC related to debt.

Other Income, Net

Other Income, Net consists of the following:

	Years ended December 31,		
(Dollars in millions)	2006	2005	2004
Regulatory interest, net	$ (3)	$ (3)	$ (6)
Allowance for equity funds used during construction	10	9	9
Sundry, net	1	8	8
Total	$ 8	$ 14	$ 11

New Accounting Standards

Pronouncements that have recently become effective that are relevant to the company and/or have had or may have a significant effect on the company's financial statements are described below.

SFAS 123 (revised 2004), "Share-Based Payment" (SFAS 123(R)): Effective January 1, 2006, Sempra Energy adopted SFAS 123(R), which requires compensation costs related to share-based transactions, including employee stock options, to be recognized in the financial statements based on fair value. SFAS 123(R) revises SFAS 123, *Accounting for Stock-Based Compensation,* and supersedes Accounting Principles Board Opinion (APBO) 25, *Accounting for Stock Issued to Employees*. In March 2005, the Securities and Exchange Commission (the SEC) issued Staff Accounting Bulletin (SAB) 107 (SAB 107) regarding the SEC's interpretation of SFAS 123(R) and the valuation of share-based payments for public companies. Sempra Energy has applied the provisions of SAB 107 in its adoption of SFAS 123(R). Further discussion of share-based compensation is provided in Note 6.

SFAS 154, "Accounting Changes and Error Corrections" (SFAS 154): SFAS 154 replaces APBO 20, *Accounting Changes,* and SFAS 3, *Reporting Accounting Changes in Interim Financial Statements*. Unless it is impracticable to do so, SFAS 154 requires retrospective application to prior periods' financial statements of voluntary changes in accounting principle and of changes required by an accounting pronouncement in instances where the pronouncement does not include specific transition provisions. This statement is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. No such changes have been made by the company in 2006.

SFAS 155, "Accounting for Certain Hybrid Financial Instruments" (SFAS 155): SFAS 155 is an amendment of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), and SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* (SFAS 140). SFAS 155 amends SFAS 133 to allow financial instruments that have embedded derivatives to be accounted for as a whole, if the holder elects to account for the whole instrument on a fair value basis, and provides additional guidance on the applicability of SFAS 133 and SFAS 140 to certain financial instruments and subordinated concentrations of credit risk. SFAS 155 is effective for all hybrid financial instruments acquired or issued by the company on or after January 1, 2007.

SFAS 157, "Fair Value Measurements" (SFAS 157): SFAS 157 defines fair value, provides guidance for using fair value to measure assets and liabilities and expands disclosures about fair value measurements. SFAS 157 applies under other standards that require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The company is in the process of evaluating the effect of this statement on its financial position and results of operations.

SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS 158): SFAS 158 amends SFAS 87, *Employers' Accounting for Pensions,* SFAS 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits,* SFAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* and SFAS 132 (revised), *Employers' Disclosures about Pensions and Other Postretirement Benefits*. SFAS 158 requires an employer to recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status, measure a plan's assets and its obligations that determine its funded status as of the end of the company's fiscal year (with limited exceptions), and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. Generally, those changes are reported in the company's comprehensive income and as a separate component of shareholders' equity. However, the effect of these liabilities is not significant to the company's financial condition or results of operation, since the costs will be offset by regulatory assets. SFAS 158 is effective for the company's 2006 Annual Report. Additional information on employee benefit plans is provided in Note 5.

The incremental effect of applying SFAS 158 on the Consolidated Balance Sheets at December 31, 2006 for all of the company's employee benefit plans is presented in the following table:

(Dollars in millions)	Prior to application of SFAS 158	SFAS 158 application adjustments	After application of SFAS 158
Regulatory assets arising from pension and other postretirement benefit obligations	$ 143	$ 77	$ 220
Sundry	$ 95	$ (23)	$ 72
Other current liabilities	$ 289	$ 1	$ 290
Pension and other postretirement benefit obligations, net of plan assets	$ 59	$ 190	$ 249
Deferred income taxes	$ 522	$ (2)	$ 520
Deferred credits and other	$ 316	$ (132)	$ 184
Accumulated other comprehensive income (loss)	$ (16)	$ (3)	$ (19)

SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115" (SFAS 159): SFAS 159 allows measurement at fair value of eligible financial assets and liabilities that are not otherwise measured at fair value. If the fair value option for an eligible item is elected, unrealized gains and losses for that item shall be reported in current earnings at each subsequent reporting date. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. This statement is effective for fiscal years beginning after November 15, 2007. The company is in the process of evaluating the application of the fair value option and its effect on its financial position and results of operations.

FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48): FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109. FIN 48 addresses how an entity should recognize, measure, classify and disclose in its financial statements uncertain tax positions that it has taken or expects to take in an income tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. While the company has not completed its analysis, it does not expect that this statement will have a significant effect on the company's consolidated financial statements.

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 a 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, 2006, SDG&E had no amounts outstanding under this facility. The facility provides support for $72 million of commercial paper outstanding at December 31, 2006.

Weighted Average Interest Rate

The company's weighted average interest rate on the total short-term debt outstanding was 5.36 percent at December 31, 2006.

Long-term Debt

	December 31,	
(Dollars in millions)	2006	2005
First mortgage bonds:		
6.8% June 1, 2015	$ 14	$ 14
5.3% November 15, 2015	250	250
Variable rate (3.30% at December 31, 2006) July 2018	161	--
5.85% June 1, 2021	60	60
6.0% June 1, 2026	250	--
5% to 5.25% December 1, 2027	150	150
2.832% to 2.972%* January and February 2034	176	176
5.35% May 15, 2035	250	250
3.06%* May 1, 2039	75	75
5.9% June 1, 2018	--	68
5.9% September 1, 2018	--	93
	1,386	1,136
6.37% Rate-reduction bonds, payable through 2007	66	132
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
	1,706	1,522
Current portion of long-term debt	(66)	(66)
Unamortized discount on long-term debt	(2)	(1)
Total	$ 1,638	$ 1,455

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

Maturities of long term debt are:

(Dollars in millions)	
2007	$ 66
2008	--
2009	--
2010	--
2011	--
Thereafter	1,640
Total	$ 1,706

Callable Bonds

At the company's option, certain bonds are callable subject to premiums at various dates: $489 million in 2007 and $274 million after 2011. In addition, $750 million of bonds are 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 $2.7 billion of first mortgage bonds at December 31, 2006.

In June 2006, SDG&E publicly offered and sold $250 million of 6 percent first mortgage bonds, maturing in 2026.

In September 2006, SDG&E issued $161 million of variable-rate first mortgage bonds, maturing in 2018. 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 have been loaned to SDG&E and will be repaid with payments on the first mortgage bonds. The proceeds from the issuance of the first mortgage bonds were used to retire an identical amount of 5.9 percent first mortgage bonds and related tax-exempt industrial development bonds of a similar weighted-average maturity.

Unsecured Long-term Debt

Various long-term obligations totaling $254 million at December 31, 2006 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 percent. These bonds were issued to facilitate the 10 percent 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. The fair values of these swaps at December 31, 2006 and 2005, were $3 million and $4 million, respectively. In 2006 and 2005, pretax income (loss) arising from the ineffective portion of interest-rate cash flow hedges was $(1) million and $4 million, respectively, recorded in Other Income, Net on the Statements of Consolidated Income. There were no balances in Accumulated Other Comprehensive Income (Loss) at December 31, 2006 and 2005, related to interest-rate cash flow hedges.

NOTE 3. FACILITIES UNDER JOINT OWNERSHIP

San Onofre Nuclear Generating Station (SONGS) and the Southwest Powerlink transmission line are owned jointly with other utilities. The company's interests at December 31, 2006 were as follows:

(Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20%	98%
Utility plant in service	$ 64	$ 310
Accumulated depreciation and amortization	$ 8	$ 162
Construction work in progress	$ 38	$ --

The company, and each of the other owners, 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 asset retirement obligation related to decommissioning costs for the SONGS units was $354 million at December 31, 2006. 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. Decommissioning cost studies are updated every three years, with the most recent update approved by the CPUC in January 2007. 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 2022, when the Units 2 and 3 NRC operating licenses will terminate and the decommissioning of Units 2 and 3 is expected to begin. At that time, sufficient funds are expected to have been collected to fully decommission SONGS.

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. The Unit 1 reactor vessel is expected to remain on site until Units 2 and 3 are decommissioned.

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.

The following tables show the fair values and gross unrealized gains and losses for the securities held in the trust funds.

	As of December 31, 2006			
(Dollars in millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Debt securities				
U.S. government issues*	$ 215	$ 10	$ (1)	$ 224
Municipal bonds**	55	1	--	56
Total debt securities	270	11	(1)	280
Equity securities	142	217	(1)	358
Cash and other securities***	61	3	--	64
Total available-for-sale securities	$ 473	$ 231	$ (2)	$ 702

* Maturity dates are 2007-2030.
** Maturity dates are 2007-2037.
*** Maturity dates are 2007-2036.

	As of December 31, 2005			
(Dollars in millions)	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Debt securities				
U.S. government issues	$ 206	$ 16	$ --	$ 222
Municipal bonds	53	2	(1)	54
Total debt securities	259	18	(1)	276
Equity securities	152	176	(1)	327
Cash and other securities	34	1	--	35
Total available-for-sale securities	$ 445	$ 195	$ (2)	$ 638

The following table shows the proceeds from sales of securities in the trust and gross realized gains and losses on those sales.

	Years Ended December 31,		
(Dollars in millions)	2006	2005	2004
Proceeds from sales	$ 474	$ 223	$ 237
Gross realized gains	$ 22	$ 17	$ 19
Gross realized losses	$ (13)	$ (11)	$ (7)

Net unrealized gains are included in Asset Retirement Obligations and Regulatory Liabilities Arising from Removal Obligations on the Consolidated Balance Sheets. The company determines the cost of securities in the trust on the basis of specific identification.

The fair value of securities in an unrealized loss position as of December 31, 2006 was $92 million. The unrealized losses were primarily caused by interest rate movements and fluctuations in the market. The company does not consider these investments to be other than temporarily impaired as of December 31, 2006.

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,		
	2006	2005	2004
Statutory federal income tax rate	35%	35%	35%
Depreciation	4	4	4
State income taxes, net of federal income tax benefit	5	6	5
Tax credits	(1)	(1)	(1)
Resolution of Internal Revenue Service audits	2	(13)	--
Other, net	(6)	(6)	(2)
Effective income tax rate	39%	25%	41%

The components of income tax expense are as follows:

	Years ended December 31,		
(Dollars in millions)	2006	2005	2004
Current:			
Federal	$ 209	$ 27	$ 107
State	73	25	41
Total	282	52	148
Deferred:			
Federal	(87)	39	15
State	(40)	1	(12)
Total	(127)	40	3
Deferred investment tax credits	(3)	(3)	(3)
Total income tax expense	$ 152	$ 89	$ 148

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, 2006, income taxes of $16 million were receivable from Sempra Energy.

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

(Dollars in millions)	2006	2005
Deferred tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 477	$ 588
Regulatory balancing accounts	160	169
Loss on reacquired debt	13	14
Property taxes	16	13
Other	8	5
Total deferred tax liabilities	674	789
Deferred tax assets:		
Postretirement benefits	101	85
Investment tax credits	22	23
Compensation-related items	16	8
State income taxes	16	20
Other accruals not yet deductible	35	59
Other	5	10
Total deferred tax assets	195	205
Net deferred income tax liability	$ 479	$ 584

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

(Dollars in millions)	2006	2005
Current asset	$ (41)	$ (7)
Noncurrent liability	520	591
Total	$ 479	$ 584

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. The company uses a December 31 measurement date for all of its plans.

In the third quarter of 2006, the Pension Protection Act of 2006 was enacted. This Act increases the funding requirements for qualified pension plans beginning in 2008. It also changes certain costs of providing pension benefits, including the interest rate for benefits paid as lump sums and the level of benefits that may be provided through qualified pension plans. The $13 million decrease in the company’s pension obligation due to the plan changes required by this legislation has been recognized in the benefit obligation and in the unrecognized prior service cost at the end of 2006. The unrecognized prior service cost will be amortized to net periodic benefit cost over approximately 13 to 15 years.

Effective March 1, 2007, the pension plans for all company employees, will be amended to change the calculation of the benefit for certain participants. The affected participants are those that had an accrued benefit under the pension plan at the date the plan transitioned from a traditional defined benefit plan to a cash balance plan, (July 1, 1998 for non-represented participants and November 1, 1998 for represented participants). Currently, these participants receive the greater of their accrued benefit in the cash balance plan or the present value of their benefit under the prior plan as of June 30, 2003. After the amendment date, they will receive the greater of the accrued benefit under the cash balance plan, or the present value of their accrued benefit under the prior plan at June 30, 2003 plus the cash balance benefit accrued after that date. This amendment resulted in a $29 million increase in the company's benefit obligation and in the unrecognized prior service cost at the end of 2006.

Effective January 1, 2006, the pension plan was amended to include deferred compensation, beginning with January 1, 2006, in pension-eligible earnings. This change resulted in a $1 million increase in the company's benefit obligation and in the unrecognized prior service cost at the end of 2006.

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

As discussed in Note 1 under "New Accounting Standards," SFAS 158 is effective for the company's 2006 Annual Report. The company has adopted SFAS 158 on a prospective basis as of December 31, 2006.

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)	2006	2005	2006	2005
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	$ 787	$ 719	$ 124	$ 85
Service cost	12	10	5	3
Interest cost	45	42	7	5
Plan amendments	17	--	--	52
Actuarial loss (gain)	34	33	11	(19)
Transfer of liability from Sempra Energy	1	35	--	2
Benefit payments	(54)	(52)	(8)	(4)
Net obligation at December 31	842	787	139	124
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	616	569	44	39
Actual return on plan assets	86	44	4	2
Employer contributions	30	21	12	7
Transfer of assets from Sempra Energy	1	34	--	--
Benefit payments	(54)	(52)	(8)	(4)
Fair value of plan assets at December 31	679	616	52	44
Funded status at December 31	(163)	(171)	(87)	(80)
Unrecognized net actuarial loss	--	138	--	1
Unrecognized prior service cost	--	4	--	46
Net recorded liability at December 31	$ (163)	$ (29)	$ (87)	$ (33)

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 included in the following captions on the Consolidated Balance Sheets as follows:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2006	2005	2006	2005
Prepaid benefit cost	$ --	$ 4	$ --	$ --
Current liabilities	(1)	--	--	--
Noncurrent liabilities	(162)	(161)	(87)	(33)
Intangible asset	--	5	--	--
Regulatory asset	--	99	--	--
Accumulated other comprehensive income (loss) - pretax	--	24	--	--
Net recorded liability	$ (163)	$ (29)	$ (87)	$ (33)

Amounts recorded in Accumulated Other Comprehensive Income (Loss) in connection with the initial adoption of SFAS 158 as of December 31, 2006, net of tax effects and amounts recorded as regulatory assets, are as follows:

(Dollars in millions)		
Net actuarial loss	$	20
Prior service (credit)		(1)
Total	$	19

At December 31, 2006 and 2005, 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)		2006		2005
Projected benefit obligation	$	812	$	757
Accumulated benefit obligation	$	809	$	752
Fair value of plan assets	$	679	$	616

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

	Pension Benefits						Other Postretirement Benefits					
(Dollars in millions)		2006		2005		2004		2006		2005		2004
Service cost	$	12	$	10	$	9	$	5	$	3	$	3
Interest cost		45		42		41		7		5		5
Expected return on assets		(41)		(44)		(40)		(2)		(2)		(3)
Amortization of:												
Prior service cost		2		3		2		3		(1)		(1)
Actuarial loss		6		1		1		--		1		1
Regulatory adjustment		8		11		(55)		(1)		1		(8)
Transfer of retirees		--		12		--		--		(1)		--
Total net periodic benefit cost (income)	$	32	$	35	$	(42)	$	12	$	6	$	(3)

The estimated net loss and prior service cost for the pension plans that will be amortized from Accumulated Other Comprehensive Income (Loss) into net periodic benefit cost in 2007 are $2 million and $3 million, respectively. The estimated net loss and prior service cost for the other postretirement plans that will be amortized from Accumulated Other Comprehensive Income (Loss) into net periodic benefit cost in 2007 are a negligible amount and $3 million.

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 is entitled to a tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2006 by $21 million and reduced the net periodic cost for 2006 by $3 million.

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

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	5.75%	5.50%	5.85%	5.60%
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	5.50%	5.66%	5.60%	5.66%
Expected return on plan assets	7.00%	7.50%	4.97%	4.61%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

The company develops the discount rate assumptions based on the results of a third party modeling tool that matches each plan's expected future benefit payments to a bond yield curve to determine their present value. It then calculates a single equivalent discount rate which produces the same present value. The modeling tool uses an actual portfolio of 500 to 600 non-callable bonds with a Moody’s Aa rating with an outstanding value of at least $50 million to develop the bond yield curve. This reflects over $300 billion in outstanding bonds with approximately 50 issues having maturities in excess of 20 years.

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.

	2006	2005
ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31:		
Health-care cost trend rate *	9.52%	9.78%
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	2009	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 2006.

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

(Dollars in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health-care benefit cost	$ --	$ --
Effect on the health-care component of the accumulated other postretirement benefit obligation	$ 5	$ (4)

Pension Plan Investment Strategy

The asset allocation for Sempra Energy's pension trust (which includes the company's pension plan and other postretirement benefit plans, except for the plans separately described below) at December 31, 2006 and 2005 and the target allocation for 2007 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2007	2006	2005
U.S. Equity	45%	46%	44%
Foreign Equity	25	24	27
Fixed Income	30	30	29
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. Other than index weight, 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, 2006 and 2005 and the target allocation for 2007 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2007	2006	2005
U.S. Equity	25%	25%	23%
Foreign Equity	5	7	6
Fixed Income	70	68	71
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 $45 million to its pension plans plan and $16 million to its other postretirement benefit plans in 2007.

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.

(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2007	$ 66	$ 6
2008	$ 70	$ 7
2009	$ 70	$ 8
2010	$ 72	$ 9
2011	$ 74	$ 10
2012-2016	$ 387	$ 61

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

(Dollars in millions)	
2007-2011	$ 2
2012-2016	$ 3

Savings Plan

The company offers a trusteed savings plan to all employees. Participation in the plan is immediate for salary deferrals for all employees. 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 2006, $11 million in 2005 and $10 million in 2004.

NOTE 6. SHARE-BASED COMPENSATION

Sempra Energy adopted SFAS 123(R) on January 1, 2006. SFAS 123(R) requires the measurement and recognition of compensation expense for all share-based payment awards made to the company’s employees and directors based on estimated fair values. Sempra Energy has share-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 share-based awards, including nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments, and dividend equivalents.

Sempra Energy currently has the following types of equity awards outstanding:

- Non-qualified Stock Options: Options have an exercise price equal to the market price of the common stock at the date of grant; are service-based, with vesting over a four-year period (subject to accelerated vesting upon a change in control or in accordance with severance pay agreements); and expire 10 years from the date of grant. Options are subject to forfeiture or earlier expiration upon termination of employment.

- Non-qualified Stock Options with Dividend Equivalents: Granted only to Pacific Enterprises' (the parent company of SoCalGas) employees through March 1998, these options include dividend equivalents which are paid upon the exercise of an otherwise in-the-money option.

- Restricted Stock: Substantially all restricted stock vests at the end of a four-year period based on Sempra Energy's total return to shareholders relative to that of market indices (subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control or in accordance with severance pay agreements). Holders of restricted stock have full voting rights. They also have full dividend rights, except for company officers, whose dividends are reinvested to purchase additional shares that become subject to the same vesting conditions as the restricted stock to which the dividends relate.

Sempra Energy adopted the provisions of SFAS 123(R) using the modified prospective transition method. In accordance with this transition method, Sempra Energy's consolidated financial statements for prior periods have not been restated to reflect the impact of SFAS 123(R). Under the modified prospective transition method, share-based compensation expense for 2006 includes compensation expense for all share-based compensation awards granted prior to, but for which the requisite service had not yet been performed as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS 123. Share-based compensation expense for all share-based compensation awards granted after January 1, 2006 is based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). Sempra Energy recognizes compensation costs net of an assumed forfeiture rate and recognizes the compensation costs for nonqualified stock options and restricted shares on a straight-line basis over the requisite service period of the award, which is generally four years. Sempra Energy estimates the forfeiture rate based on its historical experience. On January 1, 2006, Sempra Energy clarified for most restricted stock awards issued in 2003, 2004, and 2005, that Sempra Energy will offer to repurchase only enough shares to cover minimum tax withholding requirements upon vesting of the awards. Sempra Energy accounts for these awards as equity awards in accordance with SFAS 123(R).

Sempra Energy subsidiaries record an expense for the plans to the extent that subsidiary employees participate in the plans and/or the subsidiaries are allocated a portion of the Sempra Energy plans' corporate staff costs. SDG&E recorded expense of $7 million, $12 million and $9 million in 2006, 2005 and 2004, respectively. Capitalized compensation cost was $2 million for 2006.

NOTE 7. FINANCIAL INSTRUMENTS

Interest-Rate Swaps

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

Energy Contracts

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 its customers. The company records transactions for natural gas and electric energy contracts in Cost of Natural Gas and Cost of Electric Fuel and Purchased Power, respectively, in the Statements of Consolidated Income. On the Consolidated Balance Sheets, the company records corresponding regulatory assets and liabilities relating to unrealized gains and losses from these derivative instruments to the extent derivative gains and losses associated with these derivative instruments will be payable or recoverable 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:

	2006		2005	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total long-term debt*	$ 1,706	$ 1,717	$ 1,522	$ 1,544
Preferred stock **	$ 96	$ 97	$ 98	$ 96

* Before reduction for unamortized discount of $2 million and $1 million at December 31, 2006 and 2005, respectively.
** $17 million and $19 million at December 31, 2006 and 2005, 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, 2006	December 31, 2005
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	$ 25.595	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, 650,000 and 750,000 shares outstanding at December 31, 2006 and 2005, respectively*	$ 25.00	$ 17	$ 19

* At December 31, 2006 and 2005, $14 million and $16 million, respectively, were included in Deferred Credits and Other Liabilities, and $3 million and $3 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 2007; all remaining shares must be redeemed in 2008. On each of January 15, 2007 and January 15, 2006, SDG&E redeemed 100,000 shares.

During 2006, the SDG&E Board of Directors and shareholders approved an amendment to SDG&E’s articles of incorporation that authorizes SDG&E to issue up to 25 million shares of an additional class of preference shares designated as "Series Preference Stock." The Series Preference Stock is in addition to the Cumulative Preferred Stock, Preference Stock (Cumulative) and Common Stock that the company was otherwise authorized to issue, and when issued would rank junior to the Cumulative Preferred Stock and Preference Stock (Cumulative) having rights, preferences and privileges that would be established by the board at the time of issuance.

NOTE 9. ELECTRIC INDUSTRY REGULATION

Background

One legislative response to the 2000 - 2001 power crisis resulted in the purchase by the California 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 among the IOUs of the power and its administrative responsibility, including collection of power contract costs from utility customers. 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 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 Southern California Edison (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 December 2006, the CPUC issued a decision adopting the 2007 revenue requirement submitted by the DWR with a revised rate charged to customers and remitted to the DWR, effective January 1, 2007.

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 March 2006, control and ownership of the 550-megawatt (MW) Palomar generating plant was transferred from Sempra Generation, which built the plant, to SDG&E. The CPUC has approved the revenue requirement for the plant as proposed by SDG&E.

In 2006, the CPUC issued decisions finding that SDG&E's administration of power purchase agreements and procurement of least-cost dispatch power activities were reasonable and prudent during the period October 1, 2003 through December 31, 2005. The decisions further concluded that SDG&E's procurement-related revenue and expenses during this period were reasonable and prudent.

In October 2006, SDG&E, Calpine Corporation (Calpine), Otay Mesa Energy Center, LLC (OMEC), a wholly owned subsidiary of Calpine, and other Calpine affiliates, entered into an agreement, approved in September 2006 by the CPUC, for SDG&E to purchase power from a 573-MW generating facility under development in the Otay Mesa area of SDG&E's service territory. The agreement includes, among other things, an option in favor of SDG&E to purchase the facility for a fixed price at the end of the 10-year power purchase agreement (PPA) and an option in favor of the plant's owners to compel SDG&E to purchase the plant for a lower fixed price at the end of the PPA. The CPUC also approved an additional return to SDG&E to compensate it for the effect on its financial ratios from the expected requirement to consolidate OMEC in accordance with FIN 46(R), *Consolidation of Variable Interest Entities.* Among other conditions precedent, the transaction also required the approvals of the court having jurisdiction over the Calpine bankruptcy and of the FERC, which were obtained in November 2006 and January 2007, respectively. The remaining conditions precedent are expected to be resolved in the second quarter of 2007. Assuming such resolution is timely attained, the generating facility is expected to be in commercial operation by mid-2009 and annual capacity payments are estimated to be approximately $70 million.

In December 2005, SDG&E filed an application with the CPUC proposing the construction of the Sunrise Powerlink, a 500-kV transmission line between the San Diego region and the Imperial Valley that is estimated to cost $1.3 billion and be able to deliver 1,000 MW by mid-2010. The purpose of the project is to enhance reliability, provide access to renewable resources and lower the cost of certain delivered energy. SDG&E and the Imperial Irrigation District (IID) have entered into a Memorandum of Agreement (MOA) to build the project, subject to the negotiation of a definitive agreement. If the IID participates in the project in accordance with the MOA, SDG&E's share of the project is estimated to be $1.0 billion. During 2006, SDG&E reached several milestones, including the California Independent System Operator's (ISO) Board of Governors finding the proposed transmission line economically justified and needed to meet the demand for electricity in the region, the CPUC's Energy Division deeming the application complete and the company holding public participation hearings to get input on the project. In November 2006, a ruling was issued establishing the scope of the proceeding and targeting a draft decision to be issued in December 2007 and a final decision to be adopted in early 2008. In response to this ruling, SDG&E submitted supplemental testimony in January 2007 to provide additional information and analyses regarding the Sunrise Powerlink project and its potential benefits. The CPUC will also conduct additional public scoping meetings and plans to issue a draft Environmental Impact Report and Environmental Impact Statement for public comment in August 2007.

California Senate Bill 107, enacted in September 2006, requires California's IOUs to achieve a 20 percent renewable energy portfolio by 2010, instead of 2017 as previously required by state law. SDG&E already had been moving forward to achieve a 20 percent goal by 2010, consistent with California's Energy Action Plan (EAP) and EAP II. As of mid-February 2007, SDG&E has executed renewable energy contracts that are expected to supply approximately 13 percent of SDG&E's projected retail demand by the end of 2010, assuming the suppliers deliver as forecasted and the necessary transmission infrastructure is added. Also in September 2006, additional legislative bills were passed, including Assembly Bill 32 and Senate Bill 1368, mandating cuts in greenhouse gas emissions, which could impact costs and growth at SDG&E. Any cost impact is expected to be recoverable through rates. The CPUC's adoption of an interim Greenhouse Gas Emissions Performance Standard in January 2007 implements Senate Bill 1368 by prohibiting IOUs from entering into new, or renewing existing, long-term (five years or longer) contracts for electricity from base-loaded sources that emit more carbon dioxide than a modern natural gas plant (1,100 pounds of carbon dioxide per megawatt-hour). All of SDG&E's existing long-term contracts for electricity, with the exception of the supply contract with Portland General Electric for 89 MW that expires in 2013, are from sources that meet this standard. In September 2006, the CPUC issued a ruling initiating Phase II of its Electric Resource Plan Order Instituting Rulemaking (OIR) which will address the long-term electric procurement plans of SDG&E, Edison and Pacific Gas & Electric for the period 2007 - 2016. SDG&E filed its long-term plan with the CPUC in December 2006, including a ten-year resource plan that details its expected portfolio of resources over the planning horizon of 2007 - 2016. The long-term plan incorporates the renewable energy and greenhouse gas emissions standards established by the CPUC and by Senate Bill 1368. SDG&E's plan identifies, among other details, the need for additional generation resources beginning in 2010, including a baseload plant in 2012. The plan also indicates that SDG&E has an option to acquire the El Dorado power plant owned by Sempra Generation, a business unit of Sempra Energy, as discussed in Note 11 under "Other Natural Gas Cases." A CPUC decision on the long-term plan is expected to be issued by the third quarter of 2007.

San Onofre Nuclear Generating Station (SONGS)

In June 2006, the CPUC adopted a decision granting SDG&E an increase in SONGS' electric rate revenues for 2004 and 2005, which resulted in a $13.2 million increase in pretax income in the second quarter of 2006, in response to SDG&E's request for a rehearing to resolve a computational error in the CPUC's 2004

Cost of Service decision which established the revenue requirement for SDG&E's share of the operating costs of SONGS.

In May 2006, the CPUC adopted a decision in Edison's 2006 General Rate Case. In this decision, SDG&E was authorized a $21.8 million increase in its revenue requirement for 2006, which represents SDG&E's share of the cost recovery requested by Edison.

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). SDG&E will participate in the steam generator replacement project and retain its 20-percent ownership share of SONGS. During 2006, SDG&E, Edison and the CPUC's Division of Ratepayer Advocates (DRA) reached a settlement, which was subsequently approved by the CPUC, supporting SDG&E's participation in the replacement project as well as full current operating and maintenance cost recovery via balancing account treatment effective January 1, 2007. The parties agreed to defer a requested return on equity (ROE) increase (to 11.6 percent) to the next cost of capital proceeding.

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, including the company's share of costs associated with the planned steam generator replacements discussed above.

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.

Transmission Formula Rate

In December 2006, SDG&E made a filing with the FERC seeking permission to extend, with some modifications, its current transmission formula rate filings which are set to expire on June 30, 2007. If approved as filed, SDG&E's base transmission revenue requirement would increase from the current $190 million to $233 million per year. In January 2007, the FERC issued an order accepting SDG&E's proposed formula mechanism, approving SDG&E's request for a 50-basis point premium to its base ROE for participation in the ISO and establishing an effective date for the new formula rate of July 1, 2007, subject to refund, as requested by SDG&E. The current formula rate will remain in effect through June 30, 2007. Issues remaining are base ROE and certain operating and maintenance cost inputs, which will be set for hearing.

NOTE 10. OTHER REGULATORY MATTERS

CPUC Rulemaking Regarding Energy Utilities, Their Holding Companies and Non-Regulated Affiliates

In December 2006, the CPUC adopted a decision modifying the rules governing transactions between energy utilities, their holding companies and non-regulated affiliates and also revising the rules for executive compensation reporting. The purpose of the new rule changes is to strengthen the separation between the utility and its parent company and affiliates by requiring additional reporting and adopting provisions to protect a utility's financial integrity.

Advanced Metering Infrastructure

In March 2005, SDG&E submitted proposals to the CPUC for installing advanced meters with integrated two-way communications functionality. This capital investment has features that would encourage customers to conserve electricity during times of high prices or capacity constraints, and would also result in various operational efficiency and service improvements. The proposal calls for the replacement of SDG&E's 1.4 million electric customer meters, retrofit of SDG&E's 900,000 natural gas customer meters and installation of a two-way communications network and related information systems. CPUC hearings were held in September 2006, and an all-party settlement was filed on February 9, 2007. This settlement, if approved by the CPUC, adds the beneficial functionalities of remote disconnect and a home area network for all customers, thus increasing the estimated capital investment for this project from $450 million to approximately $500 million. A final CPUC decision is expected in April 2007. If the CPUC approves the project as proposed, meter installations are anticipated to commence in the fourth quarter of 2008 and be completed by early 2011.

Gain On Sale Rulemaking

In May 2006, the CPUC adopted a decision standardizing the treatment of gains and losses on future sales of utility property. It provided for an allocation of 100 percent of the gains and losses from depreciable property to ratepayers and a 50/50 allocation of gains and losses from non-depreciable property between ratepayers and shareholders. Under certain circumstances the CPUC would be able to depart from the standard allocation. The DRA and The Utility Reform Network filed a joint request for rehearing of the decision requesting, among other things, that the CPUC adopt a 90/10 allocation of gains from non-depreciable assets between ratepayers and shareholders. In December 2006, the CPUC denied the request for rehearing, but modified its prior decision revising the allocation between ratepayers and shareholders to 67/33.

General Rate Case

In December 2006, SDG&E filed a 2008 General Rate Case (GRC) application to establish its authorized 2008 revenue requirements and the ratemaking mechanisms by which those revenue requirements will change on an annual basis over the subsequent five-year period (2009 - 2013). Not included in the proceeding are fuel and purchased power and natural gas costs. Included in the GRC application are proposed mechanisms for earnings sharing, as well as performance indicators with a maximum annual reward/penalty of $15 million during the 2008 - 2013 period. Relative to authorized revenue requirements for 2006, the GRC request represents an increase of $252 million ($39 million for natural gas and $213 million for electric) in 2008. A proceeding schedule will be established in early 2007 and a final CPUC decision is expected in late 2007.

In January 2007, SDG&E filed a Phase II GRC application to update its electric marginal cost, revenue allocation and rate design. SDG&E's application sets forth several new rate design and marginal cost allocation proposals, including various dynamic pricing or time differential rate proposals that will encourage customers to shift their usage from peak demand hours to off-peak hours. Also proposed is a phase-out of the rate cap enacted by the California Legislature in 2001 at the height of California's energy crisis. Phase II hearings are expected to take place in mid-summer with a final CPUC decision by year-end 2007 and adopted rates placed into effect on January 1, 2008. Phase II applies to SDG&E only for its electric service. SDG&E will pursue a similar process for its natural gas rates and service through the Biennial Cost Allocation Proceeding which is scheduled to be filed in December 2007.

Cost of Capital

In December 2005, the CPUC approved an ROE of 10.7 percent for SDG&E, effective January 1, 2006, an increase from its prior ROE of 10.37 percent. SDG&E's authorized capital structure remains unchanged at 45.25 percent debt, 5.75 percent preferred stock and 49 percent common equity.

In October 2006, the CPUC approved SDG&E's April 2006 petition to extend to May 2007 its option to file an application to adjust its cost of capital, with any resulting changes in ROE and/or capital structure effective in 2008.

Natural Gas Market OIR

The CPUC considered natural gas market issues, including market design and infrastructure requirements, as part of its Natural Gas Market OIR. A final decision in Phase II of this proceeding was issued in September 2006, reaffirming the adequacy of the capacity of the SoCalGas and SDG&E systems to meet current demand. In particular, the Phase II decision establishes natural gas quality standards that would accommodate regasified liquefied natural gas (LNG) supplies. While the decision closed the OIR, several parties, including the South Coast Air Quality Management District (SCAQMD), filed applications with the CPUC for rehearing of the September 2006 decision, contending that the California Environmental Quality Act (CEQA) applies and that impacts on the environment should be fully considered. The CPUC plans to issue a decision on the rehearing requests in March 2007. In January 2007, the SCAQMD filed lawsuits against the CPUC in the California appeals court and the California Supreme Court challenging the CPUC's September 2006 decision and alleging that CEQA was improperly bypassed. The CPUC has asked the courts to hold the matter in abeyance pending its decision in March 2007.

In May 2006, in a related proceeding, the CPUC approved the Sempra Utilities' Phase I proposal to combine the natural gas transmission costs for SDG&E and SoCalGas so that their customers will pay the same rate for natural gas deliveries at any receipt point once LNG deliveries begin at the Otay Mesa interconnection. Phase II of this implementation proceeding addresses the Sempra Utilities' proposal to establish firm access rights and off-system delivery services to ensure that customers have reliable access to diverse supply sources. The CPUC adopted a decision in December 2006 approving the Sempra Utilities' proposals, with modifications, and directing that firm access rights and off-system services be implemented in 2008, one year after implementing tariffs are adopted in early 2007.

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, productivity and customer growth based on the most recent Consumer Price Index forecast, subject to minimum and maximum percentage increases that change annually.

The second component is a mechanism whereby any earnings that exceed a narrow band above authorized net earnings are shared with customers in varying percentages 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 are eligible for incentive awards or penalties are PBR 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. The 2004 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 each award is received. During the year ended December 31, 2006, SDG&E included in pretax earnings $5.9 million related to PBR, none of which was recorded in the fourth quarter of 2006, and $12.0 million related to DSM, which was recorded evenly over the year.

In October 2006, SDG&E submitted its Gas PBR Year 13 annual report to the CPUC requesting a $2.3 million shareholder award. A CPUC decision on the request is expected mid-2007.

The cumulative amount of certain of these awards had been subject to refund based on the outcome of the Border Price Investigation. In December 2006, the CPUC dismissed the Border Price Investigation and determined that these awards are no longer subject to refund or adjustment by virtue of the investigation. Additional discussion of this proceeding is provided in Note 11 under "Legal Proceedings."

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 Sempra Utilities. A draft audit report covering years 1997 through 2003 was provided to the CPUC's Energy Division in December 2005. In mid-2006, the CPUC decided to coordinate this proceeding with the Border Price Investigation, which was resolved and closed in December 2006. Additional discussion of this proceeding is provided in Note 11 under "Legal Proceedings."

NOTE 11. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

At December 31, 2006, the company's reserves for litigation matters were $58 million, of which $56 million related to settlements reached in January 2006 to resolve certain litigation arising out of the 2000 - 2001 California energy crisis. The uncertainties inherent in complex legal proceedings make it difficult to estimate with any degree of certainty the costs and effects of resolving legal 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.

Continental Forge Settlement

The litigation that is the subject of the January 2006 settlements is frequently referred to as the Continental Forge litigation, although the settlements also include other cases. The Continental Forge class-action and individual antitrust and unfair competition lawsuits alleged that Sempra Energy and the Sempra Utilities unlawfully sought to control natural gas and electricity markets and claimed damages of $23 billion after applicable trebling. A second settlement resolves class-action litigation brought by the Nevada Attorney General in Nevada Clark County District Court involving virtually identical allegations to those in the Continental Forge litigation.

The San Diego County Superior Court entered a final order approving the settlement of the Continental Forge class-action litigation as fair and reasonable on July 20, 2006. The California Attorney General, the DWR, the Utility Consumers Action Network and one class member have filed notices of appeal of the final order. With respect to the individual Continental Forge lawsuits, the Los Angeles City Council has not yet voted to approve the City of Los Angeles' participation in the settlement and it may elect to continue pursuing its individual case against Sempra Energy and the Sempra Utilities. The Nevada Clark County District Court entered an order approving the Nevada class-action settlement in September 2006. 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.

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, Sempra Energy and the Sempra Utilities paid $83 million in August 2006.

Additional consideration for the California settlement includes an agreement that Sempra LNG would sell to the Sempra Utilities, subject to CPUC approval, regasified LNG from its LNG terminal being constructed in Baja California, Mexico at the California border index price minus $0.02. The Sempra Utilities agreed to 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 and filed for approval at the CPUC on July 25, 2006. In addition, 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. Based on the expected volumes of power to be delivered under the contract, this discount would have potential value aggregating $300 million over the remaining six-year term of the contract. As a result of reflecting the price discount of the DWR contract in 2005, earnings reported on the DWR contract for 2006 reflected, and for subsequent years will continue to reflect, original rather than discounted power prices. The price reductions would be reduced by any amounts that exceed a $150 million threshold up to the full amount of the price reduction that Sempra Generation is ordered to pay or incurs as a monetary award, any reduction in future revenues or profits, or any increase in future costs in connection with arbitration proceedings involving the DWR contract.

The reserves recorded for the California and Nevada settlements in 2005 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 to be delivered under the DWR contract. A portion of the reserves was discounted at 7 percent, the rate specified for prepayments in the settlement agreement. For payments not addressed in the agreement and for periods from the settlement date through the estimated date of the first payment, 5 percent was used to approximate the company’s average cost of financing. Of the $377 million discussed above, per the terms of the settlement, $83 million was paid in August 2006 and an additional $83 million will be paid in August 2007. Of the remaining amount, $27.3 million is to be paid on the closing date of the settlement and $26.3 million will be paid on each successive anniversary of the closing date through the seventh anniversary of the closing date.

Other Natural Gas Cases

In November 2005, the California Attorney General and the CPUC filed a lawsuit in San Diego County Superior Court alleging that in 1998 Sempra Energy and the Sempra Utilities intentionally misled the CPUC, resulting in the utilities' California natural gas pipeline capacity being used to enable Sempra Energy to deliver natural gas to a power plant in Mexico. Plaintiffs also alleged that due to insufficient utility pipeline capacity, SDG&E curtailed natural gas service to electric generators and others, resulting in increased air pollution and higher electricity prices for California consumers from the use of oil as an alternate fuel source. In September 2006, the parties entered into a settlement that required the Sempra Utilities to pay $2 million for attorneys' fees and costs incurred by the California Attorney General, SDG&E to be given the option to purchase Sempra Generation's El Dorado power plant in 2011 for book value subject to FERC approval, and Sempra Energy to pay approximately $5.7 million to SDG&E

electricity customers beginning in 2009 to reduce SDG&E's electric procurement costs. The decisions by SDG&E and the CPUC as to whether the option should be exercised are expected to be made in 2007. In addition to resolving the lawsuit, the settlement included as a condition precedent that the CPUC permanently close the Border Price Investigation and Sempra Energy Affiliate Order Instituting Investigation, which the CPUC did in December 2006. The company recorded after-tax expense of $0.4 million in the third quarter of 2006 to reflect these settlement costs.

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, including Sempra Energy, the Sempra Utilities and Sempra Commodities, seeking recovery of damages alleged to aggregate in excess of $150 million (before trebling). The lawsuit alleged that the Sempra Energy defendants conspired with El Paso Natural Gas Company to eliminate competition, prevent the construction of natural gas pipelines to serve Nevada and other Western states, and to manipulate natural gas pipeline capacity and supply and the data provided to price indices. Plaintiffs also asserted a breach of contract claim against Sempra Commodities. The U.S. District Court dismissed the case in November 2004, determining that the FERC had exclusive jurisdiction to resolve claims. The United States Court of Appeals for the Ninth Circuit (Ninth Circuit Court of Appeals) heard oral argument on plaintiffs' appeal on February 13, 2007, and took the matter under submission.

Apart from the claims settled in connection with the Continental Forge settlement, there remain pending 13 state antitrust actions that have been coordinated in San Diego Superior Court against Sempra Energy and one or more of its affiliates (the Sempra Utilities and Sempra Commodities, depending on the lawsuit) and other, unrelated energy companies, 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 and churning transactions. The plaintiffs suing the company claim that all of the defendants in the lawsuit have damaged them in the amount of $357 million before trebling. In June 2005, the court denied the defendants' motion to dismiss on federal preemption and filed rate doctrine grounds. No trial date has been scheduled for these actions.

Pending in the federal court system are five cases against Sempra Energy, Sempra Commodities, the Sempra Utilities and various other companies, which make similar allegations to those in the state proceedings, four of which also include conspiracy allegations similar to those made in the Continental Forge litigation. The Federal District Court has dismissed four of these actions as preempted under federal law. The remaining case, which includes conspiracy allegations, has been stayed. The Ninth Circuit Court of Appeals heard oral argument on plaintiffs' appeal on February 13, 2007, and took the matter under submission.

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 dismissed 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 were subject to the filed rate doctrine and preempted by the Federal Power Act. In September 2004, the Ninth Circuit Court of Appeals affirmed the district court's ruling and in June 2005, the U.S. Supreme Court declined to review the decision. The company believes that this decision serves as a precedent for the dismissal of all other lawsuits against the Sempra Energy companies claiming manipulation of the electricity markets. In October 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 January 2007, the California Court of Appeals heard oral argument on plaintiff's appeal of the dismissal and is expected to issue its ruling in the case later in 2007.

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. SoCalGas, SDG&E and Sempra Energy reached a settlement in May 2006 with Edison that, subject to CPUC review and approval, would resolve disputes between SoCalGas, SDG&E, the other Sempra Energy companies and Edison arising over the last several years regarding the actions and activities being reviewed in the Border Price Investigation. In December 2006, the CPUC adopted a decision approving the settlement and closing the Border Price Investigation with prejudice. The settlement provides for additional transparency for the natural gas storage and procurement activities of SoCalGas and SDG&E, expands and revises SoCalGas' non-core storage program, combines the Sempra Utilities' core gas procurement functions and provides that all natural gas procurement hedging activities by SoCalGas and SDG&E will be outside the procurement incentive mechanisms and paid for by customers.

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 Administrative Law Judge (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.

Various parties appealed the FERC's order to the Ninth Circuit Court of Appeals. In September 2005, the Court of Appeals held that the FERC did not have jurisdiction to order refunds from governmental entities. SDG&E (and other California IOUs) subsequently 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. In August 2006, the Court of Appeals held that the FERC had properly established October 2, 2000 through June 20, 2001 as the refund period and had properly excluded certain bilateral transactions between sellers and the DWR from the refund proceedings. However, the court also held that the FERC erred in excluding certain multi-day transactions from the refund proceedings. Finally, while the court upheld the FERC's decision not to extend the refund proceedings to the summer period (prior to October 2, 2000), it found that the FERC had erred in not considering other remedies, such as disgorgement of profits, for tariff violations that are alleged to have occurred prior to October 2, 2000. The Court of Appeals remanded the matter to the FERC for further proceedings.

Natural Gas Contracts

SDG&E buys natural gas under short-term contracts. Purchases are from various Southwest U.S., U.S. Rockies 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 natural gas transportation contracts with various interstate pipelines that expire on various dates between 2007 and 2023. SDG&E currently purchases natural gas on a spot basis from Canada, the U.S. Rockies, 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 continues to reconfigure its pipeline capacity portfolio 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.

At December 31, 2006, the future minimum payments under existing natural gas storage and transportation contracts were:

(Dollars in millions)	
2007	$ 41
2008	21
2009	11
2010	10
2011	10
Thereafter	105
Total minimum payments	$ 198

Total payments under natural gas contracts were $380 million in 2006, $455 million in 2005 and $347 million in 2004.

Purchased-Power Contracts

For 2007, 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 20 percent, long-term contracts for 19 percent (of which 5 percent is provided by renewable contracts expiring on various dates through 2025), other SDG&E-owned generation (including Palomar) and tolling contracts for 14 percent and spot market purchases for 4 percent. The long-term contracts expire on various dates through 2032.

At December 31, 2006, the estimated future minimum payments under the long-term contracts (not including the DWR allocations) were:

(Dollars in millions)	
2007	$ 289
2008	301
2009	349
2010	310
2011	303
Thereafter	2,468
Total minimum payments	$ 4,020

The payments represent capacity charges and minimum energy purchases. The company 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 $344 million in 2006, $363 million in 2005 and $329 million in 2004.

Leases

SDG&E has operating leases on real and personal property expiring at various dates from 2007 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, 2006, the minimum rental commitments payable in future years under all noncancelable leases were as follows:

(Dollars in millions)		
2007	$	20
2008		15
2009		14
2010		12
2011		11
Thereafter		43
Total future rental commitments	$	115

Rent expense totaled $23 million in 2006, $22 million in 2005 and $20 million in 2004.

Guarantees

As of December 31, 2006, 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, 2006, the aggregate unexpended amount of this commitment was $51 million. Capital expenditures for underground conversions were $35 million in 2006, $32 million in 2005 and $23 million in 2004.

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 $14 million in 2006, $9 million in 2005 and $9 million in 2004. 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 (all three completed as of December 31, 2006 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, 2006, the company's accrued liability for environmental matters was $9.2 million, of which $8.9 million is related to cleanup at SDG&E's former fossil-fueled power plants, and $0.3 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. In connection with the issuance of operating permits, SDG&E and the other owners of SONGS previously reached an 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. At December 31, 2006, the estimated amount remaining to be spent by SDG&E through 2050 is $17 million, which is recoverable in rates.

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 $8.14 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 (for electric service only) an adjacent portion of Orange County.

NOTE 12. QUARTERLY FINANCIAL DATA

(Dollars in millions)	Quarters ended March 31	June 30	September 30	December 31
2006				
Operating revenues	$ 722	$ 664	$ 703	$ 696
Operating expenses	623	539	555	591
Operating income	$ 99	$ 125	$ 148	$ 105
Net income	$ 48	$ 66	$ 72	$ 56
Dividends on preferred stock	1	1	2	1
Earnings applicable to common shares	$ 47	$ 65	$ 70	$ 55
2005				
Operating revenues	$ 621	$ 539	$ 601	$ 751
Operating expenses	526	469	504	620
Operating income	$ 95	$ 70	$ 97	$ 131
Net income	$ 60	$ 30	$ 104	$ 73
Dividends on preferred stock	1	1	2	1
Earnings applicable to common shares	$ 59	$ 29	$ 102	$ 72

Net income for the second quarter of 2006 included $8 million from the CPUC authorization for retroactive recovery on SONGS revenues related to a computational error in the 2004 Cost of Service decision and $4 million as a result of FERC approval to recover prior year ISO charges in 2006. Net income in the third quarter of 2006 included a $13 million resolution of a prior year cost recovery issue. Net income for each of the last three quarters of 2006 included increased earnings from electric generation activities primarily from the commencement of commercial operation of the Palomar generating plant at the beginning of the second quarter. Increased earnings from electric generation included $15 million in the second quarter, $12 million in the third quarter and $14 million in the fourth quarter.

Operating revenues for the fourth quarter of 2005 included $23 million pretax from the 2005 IRS 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 pretax of California energy crisis litigation costs, offset by $38 million pretax 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 $39 million from the favorable resolution of prior years' income tax issues.

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.

There have been no changes in the company's internal control 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, 2006, 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.

Management's Report on Internal Control Over Financial Reporting is included in Item 8 herein.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 is incorporated by reference from "Corporate Governance" and "Share Ownership" in the Information Statement prepared for the May 2007 annual meeting of shareholders. The information required on the companies' executive officers is set forth below.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age*	Position*
Debra L. Reed	50	President and Chief Executive Officer
Michael R. Niggli	57	Chief Operating Officer
Dennis V. Arriola	46	Senior Vice President and Chief Financial Officer
James P. Avery	50	Senior Vice President, Electric
Lee Schavrien	52	Senior Vice President, Regulatory Affairs
Anne S. Smith	53	Senior Vice President, Customer Service
Lee M. Stewart	61	Senior Vice President, Gas Operations
Robert M. Schlax	51	Vice President, Controller and Chief Accounting Officer

* As of February 22, 2007.

Each executive officer has been an officer or employee of Sempra Energy or one of its subsidiaries for more than five years, with the exception of Mr. Schlax. Prior to joining the company in 2005, Mr. Schlax was Chief Financial Officer, Treasurer and Vice President of Finance of Mercury Air Group, Inc. since 2002. 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 "Corporate Governance", “Compensation Discussion and Analysis”, “Compensation Report of the Boards of Directors” and "Executive Compensation" in the Information Statement prepared for the May 2007 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 2007 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated by reference from "Corporate Governance" in the Information Statement prepared for the May 2007 annual meeting of shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information regarding principal accountant fees and services as required by Item 14 is incorporated by reference from "Independent Registered Public Accounting Firm" in the Information Statement prepared for the May 2007 annual meeting of shareholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(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 87 of this report.

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 Statements No. 33-45599, 33-52834, 333-52150, 33-49837, and 333-133541 on Form S-3 of our reports dated February 21, 2007 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 San Diego Gas and Electric Company's adoption of Financial Accounting Standards Board ("FASB") Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, effective December 31, 2006, and FASB 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 this Annual Report on Form 10-K of San Diego Gas and Electric Company for the year ended December 31, 2006.

/S/ DELOITTE & TOUCHE LLP

San Diego, California
February 21, 2007

SIGNATURES

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

SAN DIEGO GAS & ELECTRIC COMPANY,
(Registrant)

By: /s/ Debra L. Reed
Debra L. Reed
President and Chief Executive Officer

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

Name/Title	**Signature**	**Date**
Principal Executive Officer: Debra L. Reed President and Chief Executive Officer	/s/ Debra L. Reed	February 16, 2007
Principal Financial Officer: Dennis V. Arriola Senior Vice President and Chief Financial Officer	/s/ Dennis V. Arriola	February 16, 2007
Principal Accounting Officer: Robert M. Schlax Vice President and Controller	/s/ Robert M. Schlax	February 16, 2007
Directors: Edwin A. Guiles, Chairman	/s/ Edwin A. Guiles	February 21, 2007
Debra L. Reed, Director	/s/ Debra L. Reed	February 16, 2007
Mark A. Snell, Director	/s/ Mark A. Snell	February 20, 2007

EXHIBIT INDEX

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

Exhibit 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 as of November 10, 2006.

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 Description of preferences of Cumulative Preferred Stock, Preference Stock (Cumulative) and Series Preference Stock (incorporated by reference from SDG&E Amended and Restated Articles of Incorporation as of November 10, 2006, Exhibit 3.02 above).

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

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

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

Exhibit 10 -- Material Contracts

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

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

10.03 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).

10.04 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).

10.05 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).

10.06 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

10.07 Sempra Energy Excess Cash Balance Plan dated December 5, 2005 (2006 Sempra Energy Form 10-K, Exhibit 10.08).

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

10.09 Sempra Energy 2005 Deferred Compensation Plan (San Diego Gas & Electric Form 8-K filed on December 7, 2004, Exhibit 10.1).

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

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

10.12 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).

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

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

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

10.16 2003 Sempra Energy Executive Incentive Plan B (2003 Sempra Energy Form 10-K, Exhibit 10.10).

10.17 2003 Sempra Energy Executive Incentive Plan (June 30, 2003 Sempra Energy Form 10-Q, Exhibit 10.1).

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

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

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

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

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

Nuclear

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

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

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

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

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

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

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

10.30 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 10.23 above)(2003 Sempra Energy Form 10-K, Exhibit 10.42).

10.31 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).

10.32 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 10.31 above)(SDG&E 1996 Form 10-K, Exhibit 10.62).

10.33 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 10.31 above)(SDG&E 1996 Form 10-K, Exhibit 10.63).

10.34 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 10.31 above)(SDG&E 1999 Form 10-K, Exhibit 10.31).

10.35 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 10.31 above)(SDG&E 1999 Form 10-K, Exhibit 10.32).

10.36 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 10.31 above)(2003 Sempra Energy Form 10-K, Exhibit 10.48).

10.37 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).

10.38 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).

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, 2006, 2005, 2004, 2003 and 2002.

Exhibit 14 - Code of Ethics

14.01 Sempra Energy Code of Business Conduct and Ethics for Board of Directors and Senior Officers (also applies to directors and officers of San Diego Gas & Electric Company).

Exhibit 21 - Subsidiaries

21.01 Schedule of Subsidiaries at December 31, 2006.

Exhibit 23 – Consent of Independent Registered Public Accounting Firm, page 85.

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
Calpine	Calpine Corporation
CARB	California Air Resources Board
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CPUC	California Public Utilities Commission
DOE	Department of Energy
DRA	Division of Ratepayer Advocates
DSM	Demand Side Management
DWR	Department of Water Resources
EAP	Energy Action Plan
Edison	Southern California Edison Company
EMFs	Electric and Magnetic Fields
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation Number
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gas
GRC	General Rate Case
IID	Imperial Irrigation District
IOUs	Investor-Owned Utilities
IRS	Internal Revenue Service

ISFSI	Independent Spent Fuel Storage Installation
ISO	Independent System Operator
LIFO	Last-in first-out inventory costing method
LNG	Liquefied natural gas
mmbtu	Million British Thermal Units (of natural gas)
MOA	Memorandum of Agreement
MSCI	Morgan Stanley Capital International
MW	Megawatt
Ninth Circuit Court of Appeals	U.S. Court of Appeals for the Ninth Circuit
NRC	Nuclear Regulatory Commission
OIR	Order Instituting Rulemaking
OMEC	Otay Mesa Energy Center, LLC
PBR	Performance-Based Regulation
PGE	Portland General Electric
PIER	Public Interest Energy Research
PPA	Power Purchase Agreement
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
SAB	Staff Accounting Bulletin
SCAQMD	South Coast Air Quality Management District

SEC	Securities and Exchange Commission
SDG&E	San Diego Gas & Electric Company
Sempra Utilities	Southern California Gas Company and 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