UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2004

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.)

8330 Century Park Court, San Diego, California 92123
(Address of principal executive offices)
(Zip Code)

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

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 whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No X

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding: Wholly owned by Enova Corporation

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly 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 Legislature, the California Department of Water Resources, and the Federal Energy Regulatory Commission and other regulatory bodies in the United States; capital market 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; 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. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS.
<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
STATEMENTS OF CONSOLIDATED INCOME
(Dollars in millions)
<caption>

	Three months ended September 30, 2004	2003
<s>	<c>	<c>
Operating revenues		
Electric	$ 449	$ 579
Natural gas	101	88
Total operating revenues	550	667
Operating expenses		
Cost of electric fuel and purchased power	143	128
Cost of natural gas	61	47
Other operating expenses	135	160
Depreciation and amortization	68	63
Income taxes	50	105
Franchise fees and other taxes	29	30
Total operating expenses	486	533
Operating income	64	134
Other income and (deductions)		
Interest income	18	1
Regulatory interest - net	(1)	--
Allowance for equity funds used during construction	2	3
Income taxes on non-operating income	(5)	(3)
Other – net	--	4
Total	14	5
Interest charges		
Long-term debt	14	17
Other	3	2
Allowance for borrowed funds used during construction	(1)	(1)
Total	16	18
Net income	62	121
Preferred dividend requirements	2	1
Earnings applicable to common shares	$ 60	$ 120

See notes to Consolidated Financial Statements.
</table>

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

	Nine months ended September 30, 2004	Nine months ended September 30, 2003
<s>	<c>	<c>
Operating revenues		
Electric	$ 1,259	$ 1,378
Natural gas	407	371
Total operating revenues	1,666	1,749
Operating expenses		
Cost of electric fuel and purchased power	425	428
Cost of natural gas	233	199
Other operating expenses	426	428
Depreciation and amortization	203	179
Income taxes	121	179
Franchise fees and other taxes	84	84
Total operating expenses	1,492	1,497
Operating income	174	252
Other income and (deductions)		
Interest income	24	4
Regulatory interest - net	(4)	(4)
Allowance for equity funds used during construction	7	9
Income taxes on non-operating income	(7)	(2)
Other - net	1	4
Total	21	11
Interest charges		
Long-term debt	46	51
Other	8	5
Allowance for borrowed funds used during construction	(3)	(3)
Total	51	53
Net income	144	210
Preferred dividend requirements	4	4
Earnings applicable to common shares	$ 140	$ 206

See notes to Consolidated Financial Statements.
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<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
<caption>

<s>	September 30, 2004 <c>	December 31, 2003 <c>
ASSETS		
Utility plant - at original cost	$ 6,183	$ 5,773
Accumulated depreciation and amortization	(1,804)	(1,737)
Utility plant - net	4,379	4,036
Nuclear decommissioning trusts	575	570
Current assets:		
Cash and cash equivalents	10	148
Accounts receivable - trade	173	173
Accounts receivable – other	25	17
Interest receivable	55	37
Due from affiliates	39	151
Regulatory assets arising from fixed-price contracts and other derivatives	56	59
Other regulatory assets	77	81
Inventories	86	60
Other	24	27
Total current assets	545	753
Other assets:		
Deferred taxes recoverable in rates	250	271
Regulatory assets arising from fixed-price contracts and other derivatives	460	502
Other regulatory assets	226	281
Sundry	58	48
Total other assets	994	1,102
Total assets	$ 6,493	$ 6,461

See notes to Consolidated Financial Statements.
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CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
<caption>

<s>	September 30, 2004 <c>	December 31, 2003 <c>
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock (255 million shares authorized; 117 million shares outstanding)	$ 938	$ 938
Retained earnings	304	369
Accumulated other comprehensive income (loss)	(43)	(43)
Total common equity	1,199	1,264
Preferred stock not subject to mandatory redemption	79	79
Total shareholders' equity	1,278	1,343
Long-term debt	1,039	1,087
Total capitalization	2,317	2,430
Current liabilities:		
Accounts payable	128	193
Interest payable	10	10
Income taxes payable	146	135
Deferred income taxes	12	26
Regulatory balancing accounts – net	345	338
Fixed-price contracts and other derivatives	56	59
Current portion of long-term debt	66	66
Other	257	271
Total current liabilities	1,020	1,098
Deferred credits and other liabilities:		
Due to affiliates	238	21
Customer advances for construction	43	49
Deferred income taxes	361	360
Deferred investment tax credits	38	40
Regulatory liabilities arising from cost of removal obligations	882	846
Regulatory liabilities arising from asset retirement obligations	300	303
Fixed-price contracts and other derivatives	460	502
Asset retirement obligations	311	303
Mandatorily redeemable preferred securities	20	21
Deferred credits and other	503	488
Total deferred credits and other liabilities	3,156	2,933
Contingencies and commitments (Note 6)		
Total liabilities and shareholders' equity	$ 6,493	$ 6,461

See notes to Consolidated Financial Statements.
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<table>
SAN DIEGO GAS & ELECTRIC COMPANY AND SUBSIDIARY
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)
<caption>

<s>	Nine months ended September 30, 2004 <c>	2003 <c>
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 144	$ 210
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	203	179
Deferred income taxes and investment tax credits	3	(66)
Non-cash rate reduction bond expense	56	51
Net change in other working capital components	(79)	82
Changes in other assets	(4)	6
Changes in other liabilities	1	3
Net cash provided by operating activities	324	465
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(283)	(285)
Affiliate loan	87	45
Other - net	(6)	(6)
Net cash used in investing activities	(202)	(246)
CASH FLOWS FROM FINANCING ACTIVITIES		
Common dividends paid	(205)	(150)
Preferred dividends paid	(4)	(5)
Issuances of long-term debt	251	--
Payments on long-term debt	(299)	(48)
Redemptions of preferred stock	(3)	(1)
Net cash used in financing activities	(260)	(204)
Increase (decrease) in cash and cash equivalents	(138)	15
Cash and cash equivalents, January 1	148	159
Cash and cash equivalents, September 30	$ 10	$ 174
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Interest payments, net of amounts capitalized	$ 48	$ 48
Income tax payments, net of refunds	$ 105	$ 138

See notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. GENERAL

This Quarterly Report on Form 10-Q is that of San Diego Gas & Electric Company (SDG&E or the company). 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 all of the common stock of Southern California Gas Company (SoCalGas). SDG&E and SoCalGas are collectively referred to herein as "the California Utilities."

The accompanying Consolidated Financial Statements have been prepared in accordance with the interim-period-reporting requirements of Form 10-Q. Results of operations for interim periods are not necessarily indicative of results for the entire year. In the opinion of management, the accompanying statements reflect all adjustments necessary for a fair presentation. These adjustments are only of a normal recurring nature. Certain changes in classification have been made to prior presentations to conform to the current financial statement presentation. Specifically, certain December 31, 2003 income tax liabilities have been reclassified from Deferred Income Taxes to current Income Taxes Payable and to Deferred Credits and Other Liabilities to conform to the current presentation of these items.

Information in this Quarterly Report is unaudited and should be read in conjunction with the Annual Report on Form 10-K for the year ended December 31, 2003 (Annual Report) and the Quarterly Reports on Form 10-Q for the first and second quarters of 2004.

The company's significant accounting policies are described in Note 1 of the notes to Consolidated Financial Statements in the Annual Report. The same accounting policies are followed for interim reporting purposes.

SDG&E accounts for the economic effects of regulation on utility operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 71*, Accounting for the Effects of Certain Types of Regulation.*

NOTE 2. NEW ACCOUNTING STANDARDS

Stock-Based Compensation: On March 31, 2004, the Financial Accounting Standards Board (FASB) issued a proposed Exposure Draft to amend SFAS 123*, Accounting for Stock-Based Compensation.* The proposed statement would eliminate the choice of accounting for share-based compensation transactions using Accounting Principles Board (APB) Opinion No. 25*, Accounting for Stock Issued to Employees*, whereby no expense is recorded for most stock options, and instead would require that such transactions be accounted for using a fair-value-based method, whereby expense is recorded for stock options. It would also prohibit application by restating prior periods and would require that expense ultimately be recognized only for those options that actually vest. A final statement is expected to be issued in the fourth quarter of 2004 and be effective July 1, 2005.

SFAS 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits": This statement revises required disclosures about employers' pension plans and other postretirement benefit plans, effective in 2004. It requires disclosures beyond those in the original SFAS 132 related to the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined postretirement benefit plans. In addition, it requires interim-period disclosures regarding the amount of net periodic benefit cost recognized and the total amount of the employers' contributions paid and expected to be paid during the current fiscal year. It does not change the measurement or recognition of those plans.

The following table provides the components of benefit costs for the three and nine months ended September 30:

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	Pension Benefits		Other Postretirement Benefits	
	Three months ended September 30,		Three months ended September 30,	
(Dollars in millions)	2004	2003	2004	2003
<S>	<C>	<C>	<C>	<C>
Service cost	$ 2	$ 1	$ 1	$ --
Interest cost	10	9	1	1
Expected return on assets	(10)	(8)	--	--
Amortization of actuarial loss	--	--	1	1
Total net periodic benefit cost	$ 2	$ 2	$ 3	$ 2

	Pension Benefits		Other Postretirement Benefits	
	Nine months ended September 30,		Nine months ended September 30,	
(Dollars in millions)	2004	2003	2004	2003
Service cost	$ 6	$ 11	$ 2	$ 1
Interest cost	30	30	3	3
Expected return on assets	(29)	(25)	(1)	(1)
Amortization of:				
Transition obligation	--	--	1	1
Prior service cost	1	1	--	--
Actuarial loss	--	1	1	1
Total net periodic benefit cost	$ 8	$ 18	$ 6	$ 5

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Note 6 of the notes to Consolidated Financial Statements in the Annual Report discusses the company's expected contribution to its pension plan and other postretirement benefit plans in 2004. $3 million and $5 million of contributions have been made to its other postretirement benefit plan for the three and nine months ended September 30, 2004, respectively. There was no contribution made to its pension plan for the nine months ended September 30, 2004.

FASB Staff Position (FSP) 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003": In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted. The Act establishes a prescription drug benefit under Medicare, known as "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.

In May 2004, the FASB issued FSP 106-2 which requires that the effects of the federal subsidy be considered an actuarial gain and be recognized in the same manner as other actuarial gains and losses. In addition, FSP 106-2 requires certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. During the third quarter of 2004, the company adopted FSP 106-2 retroactive to the beginning of the year. The company and its actuarial advisors determined that benefits provided to certain participants will actuarially be at least equivalent to Medicare Part D, and, accordingly, the company will be entitled to an expected tax-exempt subsidy that reduces the company's accumulated postretirement benefit obligation under the plan at January 1, 2004 by $3 million and net periodic benefit cost for 2004 by an immaterial amount.

SFAS 143, "Accounting for Asset Retirement Obligations": Beginning in 2003, SFAS 143 requires entities to record liabilities for future costs expected to be incurred when assets are retired from service, if the retirement process is legally required. It also requires the reclassification of estimated removal costs, which have historically been recorded in accumulated depreciation, to a regulatory liability. At September 30, 2004 and December 31, 2003, the estimated removal costs recorded as a regulatory liability were $882 million and $846 million, respectively.

The change in the asset retirement obligations for the nine months ended September 30, 2004 is as follows (dollars in millions):

Balance as of January 1, 2004	$ 326
Accretion expense (interest)	17
Payments	(9)
Balance as of September 30, 2004	$ 334*

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

In June 2004, the FASB issued a proposed interpretation, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143.* The interpretation would clarify that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of SFAS 143. Accordingly, the interpretation would require an entity to recognize a liability for a conditional asset retirement obligation if the liability's fair value can be reasonably estimated. The proposed interpretation would be effective for the company on December 31, 2005.

SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"**:** Effective July 1, 2003, SFAS 149 amended and clarified accounting for derivative instruments and for hedging activities under SFAS 133. Under SFAS 149, natural gas forward contracts that are subject to unplanned netting generally do not qualify for the normal purchases and normal sales exception, whereby derivatives are not required to be marked to market when the contract is usually settled by the physical delivery of natural gas. ("Netting" refers to contract settlement by paying or receiving the monetary difference between the contract price and the market price at the date on which physical delivery would have occurred.) The company has determined that all natural gas contracts are subject to unplanned netting and as such, these contracts are marked to market. In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 are marked to market. Implementation of SFAS 149 did not have a material impact on reported net income. Additional information on derivative instruments is provided in Note 4.

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity"**:** The company adopted SFAS 150 beginning July 1, 2003 by reclassifying $24 million of mandatorily redeemable preferred stock to Deferred Credits and Other Liabilities and to Other Current Liabilities on the Consolidated Balance Sheets.

FASB Interpretation No. (FIN) 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees": The company has a residual value guarantee under a fleet lease arrangement. As of September 30, 2004, the company had no liabilities recorded for the fleet lease guarantee due to the immaterial amount of the estimated fair value of such guarantee.

FIN 46, "Consolidation of Variable Interest Entities (an interpretation of Accounting Research Bulletin (ARB) No. 51)": FIN 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the entity. Contracts under which SDG&E acquires power from generation facilities otherwise unrelated to SDG&E could result in a requirement for SDG&E to consolidate the entity that owns the facility. As permitted by the interpretation, SDG&E is continuing the process of determining whether it has any such situations and, if so, gathering the information that would be needed to perform the consolidation. The effects of this, if any, are not expected to significantly affect the financial position of SDG&E and there would be no effect on results of operations or liquidity.

NOTE 3. COMPREHENSIVE INCOME

The following is a reconciliation of net income to comprehensive income.

(Dollars in millions)	Three months ended September 30, 2004	Three months ended September 30, 2003	Nine months ended September 30, 2004	Nine months ended September 30, 2003
Net income	$ 62	$ 121	$ 144	$ 210
Minimum pension liability adjustments	--	--	--	(6)*
Comprehensive income	$ 62	$ 121	$ 144	$ 204

* This amount does not equal the change in the reported balance of accumulated other comprehensive income due to rounding.

NOTE 4. FINANCIAL INSTRUMENTS

As described in Note 8 of the notes to Consolidated Financial Statements in the Annual Report, the company follows the guidance of SFAS 133 as amended by SFAS 138 and 149 (collectively SFAS 133) to account for its derivative instruments and hedging activities. Derivative instruments and related hedged items are recognized as either assets or liabilities on the balance sheet, measured at fair value.

SFAS 133 provides for hedge accounting treatment when certain criteria are met. For derivative instruments designated as fair value hedges, the gain or loss is recognized in earnings in the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged. For derivative instruments designated as cash flow hedges, the effective portion of the derivative gain or loss is included in Other Comprehensive Income, but not reflected in the Statements of Consolidated Income until the corresponding hedged transaction is settled. Any ineffective portion is reported in earnings immediately.

The company utilizes natural gas and energy derivatives to manage commodity price risk associated with servicing its load requirements. These contracts allow the company to predict with greater certainty the effective prices to be received or paid by the company and the prices to be charged to its customers. The company also periodically enters into interest-rate swap agreements to moderate exposure to interest-rate changes and to lower the overall cost of borrowing. The use of derivative financial instruments is subject to certain limitations imposed by company policy and regulatory requirements.

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

Fixed-price Contracts and Other Derivatives

Fixed-price Contracts and Other Derivatives on the Consolidated Balance Sheets primarily reflect the company's unrealized gains and losses related to long-term delivery contracts for purchased power and natural gas transportation. The company has established offsetting regulatory assets and liabilities to the extent that these gains and losses are included in the calculation of future rates. If gains and losses are not recoverable or payable through future rates, the company applies hedge accounting if certain criteria are met. If a contract no longer meets the requirements of SFAS 133, the unrealized gains and losses and the related regulatory asset or liability will be amortized over the remaining contract life.

The changes in Fixed-price Contracts and Other Derivatives on the Consolidated Balance Sheets for the nine months ended September 30, 2004 were primarily due to physical deliveries under long-term purchased-power and natural gas transportation contracts. The transactions associated with fixed-price contracts and other derivatives had no material impact to the Statements of Consolidated Income for the nine months ended September 30, 2004 and 2003.

NOTE 5. REGULATORY MATTERS

ELECTRIC INDUSTRY REGULATION

The restructuring of California's electric utility industry has significantly affected the company's electric utility operations. In addition, the energy crisis of 2000-2001 caused the California Public Utilities Commission (CPUC) to adjust its plan for restructuring the electricity industry. The background of these issues is described in the Annual Report.

At September 30, 2004, the AB 265 Undercollection had been reduced to $23 million and SDG&E expects that the undercollection will be eliminated by the end of 2004.

The California Department of Water Resources' (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, the revenues and costs associated with the contracts are not included in the Statements of Consolidated Income.

In October 2003, the CPUC initiated a proceeding to consider a permanent methodology for allocating the DWR's revenue requirement beginning in 2004 through the remaining life of the DWR contracts. An interim allocation based on the current 2003 methodology was utilized beginning January 1, 2004, and will remain in effect until a decision is reached on a permanent methodology. In April 2004, Southern California Edison (Edison), Pacific Gas & Electric (PG&E) and a northern California consumer advocacy group proposed a limited joint settlement to allocate the DWR revenue requirement among the investor-owned utilities (IOUs). This settlement proposes to shift more than $1 billion in additional costs to SDG&E customers and would have a negative impact on customers' commodity costs over the remaining eight-year life of the DWR contracts. On July 19, 2004, the CPUC issued a proposed decision and an alternate decision recommending permanent allocations of DWR contract costs to the IOUs. These proposals were revised and third and fourth alternate decisions were issued on September 9, 2004. None of the proposed or alternate decisions would adopt the settlement; instead, they would permanently allocate a percentage of the fixed or above market costs of the contracts to SDG&E for the remaining life of the contracts (2004-2013). The CPUC is expected to address this matter at its meeting on November 19, 2004.

The judge's proposed decision and Commissioner Lynch's alternate decision would allocate 12.5 percent of the fixed costs of the contracts for the remaining term, resulting in a total shift of $1 billion to SDG&E customers. Commissioner Brown's alternate decision determines SDG&E's share of the above-market costs for all contracts for all years to be 9.9 percent, resulting in a total shift of $787 million. Commissioner Peevey's alternate decision would allocate 10.3 percent of the fixed costs of the contracts to SDG&E, resulting in a total shift of $425 million.

Although these proposed decisions would have no effect on SDG&E's net income, they could adversely affect its customer rates and SDG&E's cash flows. In the near term the effect on SDG&E's cash flows would be minor, but could become significant in the later years unless rate ceilings, imposed by Assembly Bill 1X, which freeze total rates for most residential customers at the February 2001 level, were increased to provide more-contemporaneous recovery. Until January 1, 2006, state law provides SDG&E with a recovery triggering mechanism when an over or undercollection exceeds approximately $30 million. If the triggering mechanism is not extended, the CPUC will have discretion on when to act on over and undercollections.

SDG&E's long-term resource plan identifies the forecasted needs for capacity resources within its service territory to support transmission grid reliability. An updated 10-year resource plan was filed on July 9, 2004, in a CPUC proceeding to consider utility resource planning, including energy efficiency, contracted power, demand response, qualifying facilities, renewable generation and distributed generation. SDG&E's updated long-term resource plan incorporates the resources approved by the CPUC that are discussed below, and recognizes updated goals to reach a 20-percent renewable resources target by 2010. The updated plan recommends a 500-kV transmission line addition in 2010, which would be processed for approval in a subsequent CPUC proceeding.

In order to satisfy SDG&E's recognized near-term need for grid reliability and capacity, in May 2003 SDG&E issued a Request for Proposals for the years 2005-2007 for at least 69 MW of electric capacity in 2005 increasing to 291 MW in 2007.

On June 9, 2004, the CPUC approved SDG&E's entering into five new electric resource contracts (including two under which SDG&E would take ownership, on a turnkey basis, of new generating assets, including a 550-MW plant (Palomar) being developed by Sempra Energy Resources, an affiliate, for completion in 2006), as more fully described in the Annual Report. An additional, demand-response contract was also approved. The decision authorized SDG&E to recover the costs of both contracted resources and turnkey resources, but did not adopt SDG&E's specific cost recovery, ratemaking and revenue requirement proposals for the proposed turnkey resources. On July 15, 2004, three parties filed requests for rehearing of the decision. SDG&E filed its response on July 30, 2004, opposing the requests. The CPUC is expected to rule on the requests in the next few months. In September 2004, SDG&E filed its revenue requirement and ratemaking proposals for the 45-MW combustion turbine which SDG&E will acquire as a turnkey project (Ramco facility) and filed for the Palomar facility in November 2004. The decision did not approve SDG&E's proposals for a return on equity (ROE) for SDG&E's new generation investments higher than SDG&E's ROE on distribution assets, an equity offset for the debt equivalency of purchase power contracts or an equity buildup for construction. These matters may be re-introduced for consideration in future CPUC proceedings.

NATURAL GAS MARKET OIR

The CPUC's Natural Gas Market Order Instituting Rulemaking (OIR) was instituted on January 22, 2004, and will be addressed in two phases. A decision on Phase I was issued on September 2, 2004 and the schedule for Phase II calls for a decision by the end of 2004. Further discussion of Phase I and Phase II is included in the Annual Report. The focus of the Gas OIR is the period from 2006 to 2016. Since Natural Gas Industry Restructuring (GIR), as discussed in the Annual Report, would end in August 2006 and there is overlap between GIR and the OIR issues, a number of parties (including SoCalGas) have requested the CPUC not to implement GIR.

The California Utilities have made comprehensive filings in the OIR outlining a proposed market structure that is intended to create access to new natural gas supply sources (such as liquefied natural gas (LNG)) for California. In their Phase I and Phase II filings, SoCalGas and SDG&E proposed a framework to provide firm tradable access rights for intrastate natural gas transportation; provide SoCalGas with continued balancing account protection for intrastate transmission and distribution revenues, thereby eliminating throughput risk; and integrate the transmission systems of SoCalGas and SDG&E so as to have common rates and rules. The California Utilities also proposed that the capital expenditures necessary to access new sources of supply be included in ratebase and that the total amount of the expenditures would be $200 million to $300 million.

The California Utilities also proposed a methodology and framework to be used by the CPUC for granting pre-approval of new interstate transportation agreements. The Phase I decision approves the California Utilities' transportation capacity pre-approval procedures with some modifications. SoCalGas' existing pipeline capacity contract with Transwestern Pipeline Company expires in November 2005 and its primary contracts with El Paso Natural Gas Company expire in August 2006.

Discussions are underway pursuant to the framework approved by the CPUC to acquire replacement capacity. The Phase 1 decision also directs the California Utilities to file, by December 2, 2004, an application to implement proposals for transmission system integration, firm access rights, and off-system delivery services. The CPUC has determined that project developers, not the utilities, will be presumed to pay for the costs for access-related infrastructure, subject to future applications to be filed when more is known about the particular projects. Phase II of the Gas Market OIR will review the CPUC's ratemaking policies on throughput risk to better align these with its objectives of promoting energy conservation and adequate infrastructure. Phase II will also investigate the need for emergency natural gas storage reserves and the role of the utility in backstopping the noncore market.

COST OF SERVICE FILINGS

In 2002, the California Utilities filed cost of service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs, as further discussed in the Annual Report. SDG&E requested revenue increases of $64 million. As previously reported, in December 2003 SDG&E filed with the CPUC a proposed settlement of its cost of service proceeding. The settlement, if approved by the CPUC, would reduce the company's annual rate revenues by an aggregate net amount of approximately $13 million from the rates in effect during 2003. The CPUC's Office of Ratepayer Advocates (ORA) and most other major parties to the cost of service proceedings have recommended that the CPUC approve the settlement.

On September 28, 2004, the CPUC's Administrative Law Judge (ALJ) and the CPUC Commissioner assigned to the cost of service proceedings issued differing proposed decisions for consideration by the CPUC. Both of these proposed decisions recommend that the CPUC reject the proposed settlement. The ALJ's proposed decision would, if adopted by the CPUC, increase annual rate revenues by $16 million from that contemplated by the settlement but would also adopt a one-way balancing account requiring that any reductions in operating labor costs from those estimated in establishing rates be refunded to customers. CPUC Commissioner Wood's alternate proposed decision, which does not include a one-way labor balancing account, would, if adopted by the CPUC, increase the annual rate reduction by an additional $32 million from that contemplated by the proposed settlement.

The company believes that a factual error relating to its nuclear electric rate revenues was applied in the proposed decisions of both the ALJ and Commissioner Wood. The company also believes that Commissioner Wood's proposed decision contains a depreciation error. If these errors and other, minor factual errors are corrected, they would increase the annual rate revenues that would be provided by the ALJ's proposed decision to $47 million above that contemplated by the settlement and would increase the annual rate revenues that would be provided by Commissioner Wood's alternative proposed decision to $16 million above that contemplated by the settlement. Both proposed decisions would approve balancing accounts for pension costs similar to those contemplated by the settlement and various other cost balancing accounts not contemplated by the settlement. All the proposals contemplate that the rates resulting from the cost of service proceedings would remain effective through 2007 subject to annual attrition adjustments.

The company previously reported that it expects that another CPUC commissioner will issue an additional proposed decision that, if adopted by the CPUC, would essentially approve the proposed settlements. Subsequently, on October 28, 2004, the CPUC at its regularly scheduled meeting deferred acting on the cost of service proceedings at the request of Commissioner Brown, who stated that he would issue an additional proposed decision.

The CPUC may adopt any one of the proposed decisions or reject all of them and adopt a different outcome. The company expects that a CPUC decision will be issued by year end.

The CPUC previously ordered that any changes in rates resulting from the cost of service proceedings would be effective retroactively to January 1, 2004. Consequently, during 2004 the company has, in general, recorded revenue and resulting net income in a manner consistent with the reduced rates contemplated by the proposed settlement, except for the favorable effect of the recovery of pension costs contemplated by the proposed settlement and provided by the proposed decisions. To the extent that the revenues provided by the CPUC's decision in the cost of service proceedings differ from those previously recorded, a reconciling adjustment to revenues and resulting net income would be recorded in the latest quarter for which financial statements had not been published.

Other ratemaking issues are included in Phase II of the cost of service proceeding. In addition to recommending changes in the performance-based regulation (PBR) formulas, the ORA also proposed the possibility of performance penalties for service quality, safety and electric service reliability, without the possibility of performance awards. Hearings took place in June 2004. On July 21, 2004, all of the active parties in Phase II who dealt with post test year ratemaking and performance incentives filed for adoption by the CPUC of an all-party settlement agreement for most of the Phase II issues, including annual inflation adjustments and revenue sharing. The agreement does not cover performance incentives. For the interim years of 2005-2007, the Consumer Price Index would be used to adjust the escalatable authorized base rate revenues within identified floors and ceilings. It is not likely that the CPUC will address this matter in its decision related to Phase II of this proceeding before year-end 2004. Consequently, to ensure that the results of Phase II would be applicable for a full year in 2005, SoCalGas and SDG&E filed with the CPUC on September 29, 2004, a petition to modify a prior decision that provided for the differences between 2004's rates and the amounts determined in the cost of service decision to be collected or refunded in future rates, to also apply to similar differences occurring in 2005 prior to implementation of the cost of service decision.

SDG&E had filed for continuation of existing PBR mechanisms for service quality and safety that would otherwise expire at the end of 2003. In January 2004, the CPUC issued a decision that extended 2003 service and safety targets through 2004, but did not determine the applicability of rewards or penalties. As part of the proposed Phase II Settlement Agreement, Revenue Sharing, under which IOUs return to customers a percentage of earnings above specified levels, would be suspended for 2004 and resume for 2005 through 2007. The proposed revenue sharing mechanism also provides the utility the option to file for suspension of the earnings sharing mechanism if earnings for two consecutive years fall 175 basis points or more below its authorized rate of return; however, if earnings are 300 or more basis points above the utility's authorized rate of return, the revenue sharing mechanism would be automatically suspended and trigger a formal regulatory review by the CPUC to determine whether modification of the ratemaking mechanism is required.

Edison's CPUC decision on its cost of service application sets rates for San Onofre Nuclear Generating Station (SONGS), 20 percent of which is owned by SDG&E. As discussed in the Annual Report, 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 capital additions. Edison has applied for permission to replace SONGS' steam generators, which would increase the total cost of SONGS by an estimated $800 million ($160 million for SDG&E). SDG&E has the option of not participating in the project and has informed Edison of its intention to exercise this option. Doing so would reduce SDG&E's ownership percentage in SONGS by an amount to be determined in arbitration and will be subject to CPUC review and approval. Such approval is expected to occur during late 2005. If the proposed reduction of SDG&E's ownership percentage resulting from the arbitration is unacceptable, SDG&E may elect to participate in the replacement project.

During the current SONGS Unit 3 refueling outage, Edison reported that it had performed inspections of two pressurizer sleeves and found evidence of degradation. Degradation of the pressurizer sleeves has been a concern in the nuclear industry for some time. Edison had been planning to replace all of the sleeves in Units 2 and 3 during the next refueling for each unit in 2005 and 2006, but has reported its intention to move the planned replacement of Unit 3's pressurizer sleeves forward from 2006 to the current outage. This extra work will lengthen the current outage from 55 days to a range of 95 to 110 days, but allows Edison to move the 2006 refueling outage out of the peak summer period to the fall or winter of 2006. Edison has reported that it will incur about $9 million of capital expenditures during 2005 that otherwise would have occurred in 2006. SDG&E's share would be approximately $2 million. Edison plans to replace the pressurizer sleeves in Unit 2 during its next scheduled outage in 2005.

Also during the current outage, Edison reported that it had conducted a planned inspection of the Unit 3 reactor vessel head and found indications of degradation. Although the degradation is far below the level at which leakage would occur, Edison plans to make repairs during the current outage. While Edison reports that this is the first experience at SONGS of this kind of degradation to the reactor vessel heads, the detection and repair of similar degradation at other plants are now common in the industry. Edison reports that it plans to replace the Unit 2 and Unit 3 reactor vessel heads during refueling outages in 2009-2010.

PERFORMANCE-BASED REGULATION

As further described in the Annual Report, under PBR, the CPUC requires future income potential to be tied to achieving or exceeding specific performance and productivity goals, rather than relying solely on expanding utility plant to increase earnings. PBR and demand-side management (DSM) rewards are not included in the company's earnings before CPUC approval is received.

The only incentive reward approved during the nine months ended September 30, 2004 consisted of $1.5 million related to SDG&E's Year 10 natural gas PBR, which was approved on August 22, 2004. This reward was awarded by the CPUC subject to refund based on the outcome of the Border Price Investigation, as discussed below. The cumulative amount of rewards subject to refund based on the outcome of the Border Price Investigation is $8.2 million, all of which has been included in net income.

At September 30, 2004, the following performance incentives were pending CPUC approval and, therefore, were not included in the company's earnings (dollars in millions):

Program	
DSM/Energy Efficiency*	$ 37.7
2003 Distribution PBR	8.2
Total	$ 45.9

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

SOUTHERN CALIFORNIA FIRES

Several major wildfires that began on October 26, 2003 severely damaged SDG&E's infrastructure, causing a significant number of customers to be without utility services. On October 27, 2003, then governor Gray Davis declared a State of Emergency for the State of California. The declaration authorized the establishment of catastrophic event memorandum accounts (CEMA) to record all incremental costs (costs not already included in rates) associated with the repair of facilities and the restoration of service. Incremental electric distribution and natural gas related costs are recovered through the CEMA. Electric transmission related costs are recovered through the annual FERC true-up proceeding. Incremental costs incurred related to the wildfires and recoverable through the CEMA were $38 million.

On June 28, 2004, SDG&E filed its CEMA application with the CPUC to recover incremental operating and maintenance and capital costs of its natural gas and electric distribution systems associated with the fires. In that application, SDG&E is requesting a 2005 revenue requirement of $20 million, representing the operating and maintenance costs of $12 million plus the 2004 and 2005 ongoing annual amounts of $4 million to recover the $26 million of capital costs and the authorized return thereon. The company expects no significant effect on earnings from the fires. The ALJ indicated that he expects to issue a proposed decision by the end of the first quarter of 2005.

COST OF CAPITAL

Effective January 1, 2005, SDG&E's authorized return on rate base (ROR) and return on equity (ROE) will be 8.18 percent and 10.37 percent, respectively, for its electric distribution and natural gas businesses, down from 8.77 percent and 10.9 percent, respectively. The decrease is a result of the CPUC's automatic triggering mechanism, which resets these rates whenever Moody's Aa utility bond yield as published by Mergent Bond Record changes by more than a specified amount. The new benchmark will be 6.19 percent and another automatic adjustment would be triggered if the Mergent Aa utility bond yield were to average less than 5.19 percent or greater than 7.19 percent during the April - September timeframe of any given year. If the cost of service proceeding described above is decided by the CPUC along the lines of the settlement, the effect of the changes in ROR and ROE would be to decrease net income in 2005 by $10 million from what it would have been if the rates had not changed. The electric-transmission cost of capital is determined under a FERC proceeding.

BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

The BCAP determines the allocation of authorized costs between customer classes for natural gas transportation service provided by the company and adjusts rates to reflect variances in sales volumes as compared to the forecasts previously used in establishing transportation rates. SDG&E filed with the CPUC its 2005 BCAP application in September 2003, requesting updated transportation rates effective January 1, 2005. In November 2003, an Assigned Commissioner Ruling delayed the BCAP application until a decision is issued in the GIR implementation proceeding. As a result of the April 1, 2004 decision on GIR implementation as described in Natural Gas Industry Restructuring in the Annual Report, on May 27, 2004 the ALJ in the 2005 BCAP issued a decision dismissing the BCAP application. The company is required to file a new BCAP application after the stay of the GIR implementation decision is lifted.

BORDER PRICE INVESTIGATION

In November 2002, the CPUC instituted an investigation into the Southern California natural gas market and the price of natural gas delivered to the California - Arizona border between March 2000 and May 2001. The California Utilities are the parties to the first phase of the investigation. If the investigation were to determine that the conduct of either of the California Utilities contributed to the natural gas price spikes that occurred during the investigation period, the CPUC may modify the party's natural gas procurement incentive mechanism, reduce the amount of any shareholder award for the period involved, and/or order the party to issue a refund to ratepayers. At September 30, 2004, the cumulative amount of shareholder awards, all of which has been included in net income, was $8.2 million. The first phase of this investigation was reopened for one day on October 25, 2004, for additional testimony and supplemental opening and reply briefs. While the ALJ stated that a proposed decision is not imminent, the company expects that a proposed decision will be issued before year end for consideration by the CPUC. Although the proposed decision may be adverse to it, the company believes it is unlikely that the full CPUC would adopt any such adverse decision and would instead conclude that the California Utilities were not responsible for any natural gas price spikes. A final CPUC decision in the first phase of the investigation is not expected until 2005.

CPUC INVESTIGATION OF ENERGY-UTILITY HOLDING COMPANIES

The CPUC has initiated an investigation into the relationship between California's IOUs and their parent holding companies. The CPUC broadly determined that it could, in appropriate circumstances, require the holding company to provide cash to a utility subsidiary to cover its operating expenses and working capital to the extent they are not adequately funded through retail rates. This would be in addition to the requirement of holding companies to provide for their utility subsidiaries' capital requirements, as the IOUs previously acknowledged in connection with the holding companies' formations. In January 2002, the CPUC ruled that it had jurisdiction to create the holding company system and, therefore, retains jurisdiction to enforce conditions to which the holding companies had agreed.

In an opinion issued May 21, 2004, the California Court of Appeal upheld the CPUC's assertion of limited enforcement jurisdiction, but concluded that the CPUC's interpretation of the "first priority" condition (that the holding companies could be required to infuse cash into the utilities as necessary to meet the utilities' obligation to serve) was not ripe for review. In September 2004, the California Supreme Court declined to review the California Court of Appeal's decision.

RECOVERY OF CERTAIN DISALLOWED TRANSMISSION COSTS

The Federal Court of Appeals scheduled completion of briefing by February 9, 2005, and set oral argument for April 14, 2005, concerning SDG&E's recovery of the differentials between certain payments to SDG&E by its co-owners of the Southwest Powerlink (SWPL) and charges assessed to SDG&E under the California Independent System Operator (ISO) FERC tariff for transmission line losses, and grid management and other charges related to energy schedules of its SWPL co-owners. The parties in the related private arbitration have agreed to hold the arbitration in abeyance pending resolution of the FERC tariff proceeding.

FERC ACTIONS

Refund Proceedings

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

In December 2002, a FERC ALJ issued preliminary findings indicating that the California 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). On March 26, 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 26 order estimates that the replacement formula for estimating natural gas prices will increase the refund obligations from $1.8 billion to more than $3 billion for the same time period. Pending in the Ninth Circuit are various parties' appeals on aspects of the FERC's order.

In a series of orders in 2004, the FERC has provided further direction and clarifications regarding the methodology to be used by the ISO and PX to recalculate the precise refund obligations and entitlements through their settlement models.

Manipulation Investigation

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

On June 25, 2003, the FERC issued several orders requiring various entities to show cause why they should not be found to have violated California ISO and PX tariffs. The FERC directed 43 entities, including SDG&E, to show cause why they should not disgorge profits from certain transactions between January 1, 2000 and June 20, 2001 that are asserted to have constituted gaming and/or anomalous market behavior under the California ISO and/or PX tariffs. SDG&E and the FERC resolved the matter through a settlement, which documents the ISO's finding that SDG&E did not engage in market activities in violation of the ISO or PX tariffs, and in which SDG&E agreed to pay $27,792 into a FERC-established fund.

NOTE 6. CONTINGENCIES

NUCLEAR INSURANCE

SDG&E and the other owners of SONGS have insurance to respond to nuclear liability claims related to SONGS. Detail of the coverage is provided in the Annual Report. As of September 30, 2004, the secondary financial protection provided by the Price-Anderson Act is $10.5 billion if the liability loss exceeds the insurance limit of $300 million. In addition, the maximum SDG&E could be assessed is $8.8

million should there be a retrospective premium call under the risk sharing arrangements of the nuclear property, decontamination and debris removal insurance policy.

Both 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. An industry aggregate limit of $300 million exists for liability claims, regardless of the number of non-certified acts affecting SONGS or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.24 billion exists for property claims, including replacement power costs, for non-certified acts of terrorism affecting SONGS or any other nuclear energy facility property policy within twelve months from the date of the first act. 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.

SPENT NUCLEAR FUEL

SONGS owners have responsibility for the interim storage of spent nuclear fuel generated at SONGS until it is accepted by the DOE for final disposal. Spent nuclear fuel is stored in the SONGS Units 1, 2 and 3 Spent Fuel Pools (SFP) and the SONGS Independent Spent Fuel Storage Installation (ISFSI). Movement of Unit 1 spent fuel from the Unit 3 SFP to the ISFSI was completed in late 2003. Movement of Unit 1 spent fuel from the Unit 1 SFP to the ISFSI is scheduled to be completed by the end of 2004 and from the Unit 2 SFP to the ISFSI by late 2005. With these moves, there will be sufficient space in the Unit 2 and 3 SFPs to meet plant requirements through mid-2007 and mid-2008, respectively.

LITIGATION

Except for the matters referred to below, neither the company nor its subsidiary are party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses. Management believes that none of these matters will have further material adverse effect on the company's financial condition or results of operations.

Energy Crisis Litigation

In 2000 and 2001, California experienced a severe energy crisis characterized by dramatic increases in the prices of electricity and natural gas. Many, often duplicative, lawsuits have been filed against numerous energy companies seeking overlapping damages aggregating in the tens of billions of dollars for allegedly unlawful activities asserted to have caused or contributed to the energy crisis. In addition, the energy crisis has generated numerous governmental investigations and regulatory proceedings. The company is cooperating in various investigations, including an investigation being conducted by the California Attorney General into possible anti-competitive behavior. The material regulatory proceedings arising out of the energy crisis that involve the company are briefly summarized, along with other proceedings, in Note 5 and this Note 6. The lawsuits arising out of the energy crisis to which the company is a defendant are briefly summarized below.

Natural Gas Cases

Class-action and individual antitrust and unfair competition lawsuits filed in 2000 and thereafter, and currently consolidated in San Diego Superior Court seek damages, alleging that Sempra Energy, SoCalGas and SDG&E, along with El Paso Natural Gas Company (El Paso) and several of its affiliates, unlawfully sought to control natural gas and electricity markets. In December 2003, the Court approved a settlement whereby the applicable El Paso entities (including cases involving unrelated claims not applicable to Sempra Energy, SoCalGas or SDG&E) will pay approximately $1.7 billion to resolve these claims. The proceeding against Sempra Energy and the California Utilities has not been settled and continues to be litigated. During the third quarter of 2004, the court denied motions by Sempra Energy and the California Utilities for summary judgment in their favor. Sempra Energy and the California Utilities have requested the Court of Appeal to review these denials; however, such an interim review pending a final decision on the merits of the case is entirely at the discretion of the appellate court. In October 2004, certain of the plaintiffs issued a news release asserting that they could recover as much as $24 billion from Sempra Energy and the California Utilities if their allegations were upheld at trial. The trial of the case was previously set for September 2004 but has been postponed and the newly assigned judge has yet to schedule a new trial date. (The original judge is retiring at year end.)

Similar lawsuits have been filed by the Attorneys General of Arizona and Nevada, alleging that El Paso and certain Sempra Energy subsidiaries unlawfully sought to control the natural gas market in their respective states. The claims against the Sempra Energy defendants in the Arizona lawsuit were settled in September 2004 for $150,000 and have been dismissed with prejudice.

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in U.S. District Court in Las Vegas against major natural gas suppliers, including Sempra Energy, the California Utilities and other company subsidiaries, seeking recovery of damages alleged to aggregate in excess of $150 million (before trebling) from an alleged conspiracy to drive up or control natural gas prices, eliminate competition and increase market volatility, breach of contract and wire fraud. On January 27, 2004, the U.S. District Court dismissed the Sierra Pacific Resources case against all of the defendants, determining that this is a matter for the FERC to resolve. However, the court granted plaintiffs' request to amend their complaint, which they have done and Sempra Energy has filed another motion to dismiss, which is scheduled to be heard on November 29, 2004.

In July 2004, the City and County of San Francisco, the County of Santa Clara and the County of San Diego brought actions, alleging that energy prices were unlawfully manipulated by defendants' reporting artificially inflated natural gas prices to trade publications and by entering into wash trades and by engaging in "churning" transactions with Reliant Energy, in San Diego Superior Court against various entities, including Sempra Energy, SET, SoCalGas and SDG&E.

Electricity Cases

Various antitrust lawsuits, which seek class-action certification, allege that numerous entities, including Sempra Energy and certain subsidiaries, including SDG&E, that participated in the wholesale electricity markets unlawfully manipulated those markets. Collectively, these lawsuits allege damages against all defendants in an aggregate amount in excess of $16 billion (before trebling). In January 2003, the federal court granted a motion to dismiss one of these lawsuits, filed by Snohomish County, Washington Public Utility District, on the grounds that the claims contained in the complaint were subject to the filed rate doctrine and were preempted by the Federal Power Act. That ruling was appealed to the Ninth Circuit U.S. Court of Appeals.

Other Litigation

The Utility Consumers' Action Network (UCAN), a consumer-advocacy group which had requested a CPUC rehearing of a CPUC decision concerning the allocation of certain power contract gains between SDG&E customers and the company, appealed the CPUC's rehearing denial to the California Court of Appeal. On July 12, 2004, the Court of Appeal affirmed the CPUC's decision. On August 20, 2004, UCAN filed a Petition for Review in the California Supreme Court. The Supreme Court has not yet determined whether it will grant review.

ITEM 2.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with the financial statements contained in this Form 10-Q and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Risk Factors" contained in the Annual Report.

RESULTS OF OPERATIONS

Revenues and Cost of Sales

Electric revenues decreased to $1.3 billion for the nine months ended September 30, 2004 from $1.4 billion for the same period in 2003, and the cost of electric fuel and purchased power decreased to $425 million in 2004 from $428 million in 2003. Additionally, electric revenues decreased to $449 million for the quarter ended September 30, 2004 from $579 million for the same period in 2003, and the cost of electric fuel and purchased power increased to $143 million in 2004 from $128 million in 2003. The decreases in revenues were due to the recognition of $116 million related to the approved settlement of intermediate-term purchase power contracts in the third quarter of 2003, more power being provided to SDG&E's customers by the DWR in 2004 as discussed in Note 5 of the notes to Consolidated Financial Statements, and higher earnings from PBR awards in 2003. The decrease in the cost of electric fuel and purchased power for the nine-month period was mainly due to more power being provided by the DWR, while the increase for the three-month period was due to higher electric commodity costs partially offset by more power being provided by the DWR. Under the current regulatory framework, changes in commodity costs normally do not affect net income. Performance awards are discussed in Note 5 of the notes to Consolidated Financial Statements.

Natural gas revenues increased to $407 million for the nine months ended September 30, 2004 from $371 million for the corresponding period in 2003, and the cost of natural gas increased to $233 million in 2004 from $199 million in 2003. Additionally, natural gas revenues were $101 million for the quarter ended September 30, 2004 compared to $88 million for the corresponding period in 2003, and the cost of natural gas was $61 million in 2004 compared to $47 million in 2003. These increases were primarily attributable to natural gas cost increases, which are passed on to customers.

In 2002, the California Utilities filed Cost of Service applications with the CPUC, seeking rate increases reflecting forecasts of 2004 capital and operating costs, as further discussed in the Annual Report and in Note 5 of the notes to Consolidated Financial Statements. In accordance with generally accepted accounting principles, SDG&E is generally recognizing 2004 revenue in a manner consistent with the reduced rates contemplated by the proposed settlements, except for the favorable effect of the recovery of pension costs contemplated by the proposed settlements and provided by both proposed decisions. To the extent that the revenues provided by the CPUC's decision in the cost of service proceedings differ from those previously recorded, a reconciling adjustment to revenues and resulting net income would be recorded in the latest quarter for which financial statements had not been published. To date, the impacts of accounting consistent with the settlement have not had a material effect on the financial statements.

The tables below summarize the electric and natural gas volumes and revenues by customer class for the nine months ended September 30, 2004 and 2003.

<table>
Electric Distribution and Transmission
(Volumes in millions of kilowatt hours, dollars in millions)
<caption>

	2004		2003	
	Volumes	Revenue	Volumes	Revenue
<S>	<C>	<C>	<C>	<C>
Residential	5,242	$ 518	4,988	$ 561
Commercial	4,960	487	4,681	526
Industrial	1,542	99	1,468	126
Direct access	2,560	77	2,456	62
Street and highway lighting	71	8	68	8
Off-system sales	--	-	26	1
	14,375	1,189	13,687	1,284
Balancing accounts and other		70		94
Total		$ 1,259		$ 1,378

</table>

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

Beginning in 2004, off-system sales are accounted for as a reduction of the cost of purchased power.

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

	Gas Sales		Transportation & Exchange		Total	
	Volumes	Revenue	Volumes	Revenue	Volumes	Revenue
<S>	<C>	<C>	<C>	<C>	<C>	<C>
2004:						
Residential	25	$ 238	--	$ --	25	$ 238
Commercial and industrial	13	104	3	3	16	107
Electric generation plants	--	-	53	26	53	26
	38	$ 342	56	$ 29	94	371
Balancing accounts and other						36
Total						$ 407
2003:						
Residential	24	$ 220	--	$ --	24	$ 220
Commercial and industrial	13	95	3	4	16	99
Electric generation plants	--	3	45	22	45	25
	37	$ 318	48	$ 26	85	344
Balancing accounts and other						27
Total						$ 371

</table>

Other Operating Expenses

Other operating expenses decreased to $426 million for the nine-month period ended September 30, 2004 from $428 million for the same period in 2003 and decreased to $135 million for the quarter ended September 30, 2004 from $160 million for the same period in 2003 due to litigation charges in the third quarter of 2003 offset partially by increases in other operating expenses in 2004.

Interest Income

Interest income increased to $24 million for the nine months ended September 30, 2004 from $4 million for the same period of 2003, and increased to $18 million for the quarter ended September 30, 2004 from $1 million for the same period of 2003. The changes were due primarily to interest on income tax receivables during the first and third quarters of 2004.

Income Taxes

Income tax expense decreased to $128 million for the nine months ended September 30, 2004 from $181 million for the same period of 2003. The corresponding effective income tax rates were 47.1 percent and 46.3

percent, respectively. Additionally, income tax expense decreased to $55 million for the third quarter of 2004 compared to $108 million for the third quarter of 2003, and the corresponding effective income tax rates were 47.0 percent and 47.2 percent, respectively. The changes were due primarily to lower taxable income in 2004.

Net Income

SDG&E recorded net income of $144 million and $210 million for the nine-month periods ended September 30, 2004 and 2003, respectively, and net income of $62 million and $121 million for the quarters ended September 30, 2004 and 2003, respectively. The decreases were primarily due to income of $65 million after-tax in 2003 related to the approved settlement of intermediate-term purchase power contracts, the 2003 Incremental Cost Incentive Pricing for SONGS, higher performance awards in 2003 and higher depreciation expense in 2004 partially offset by higher electric transmission and distribution revenues (excluding the effects of the settlement, which are included in Revenues) in 2004, and by higher operating expenses in 2003 including litigation charges in the third quarter.

CAPITAL RESOURCES AND LIQUIDITY

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

At September 30, 2004, the company had $10 million in cash and $300 million in available unused, committed lines of credit.

Management believes that cash flows from operations and debt issuances will be adequate to finance capital expenditure requirements and other commitments. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activities in a manner consistent with its intention to maintain strong, investment-quality credit ratings. Rating agencies and others that evaluate a company's liquidity generally consider a company's capital expenditures and working capital requirements in comparison to cash from operations, available credit lines and other sources available to meet liquidity requirements.

CASH FLOWS FROM OPERATING ACTIVITIES

Net cash provided by operating activities totaled $324 million and $465 million for the nine months ended September 30, 2004 and 2003, respectively. The decrease was mainly due to lower net income and a decrease in accounts payable in 2004 compared to an increase in 2003.

For the nine months ended September 30, 2004, the company contributed $5 million to other postretirement benefit plans but made no contribution to the pension plan.

CASH FLOWS FROM INVESTING ACTIVITIES

Net cash used in investing activities totaled $202 million and $246 million for the nine months ended September 30, 2004 and 2003, respectively. The change was primarily due to higher repayments of an intercompany loan by Sempra Energy in 2004.

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

In September 2004, the CPUC approved a proposed framework for the contracting of interstate pipeline capacity for core customers. Discussions are underway for the California Utilities to acquire pipeline capacity to replace capacity contracts expiring over the next two years. The CPUC also approved requests to establish receipt points to accept new supplies, including imported LNG, to the California Utilities' service area. Approval for a point of receipt to import natural gas from Mexico to Southern California via pipelines at Otay Mesa was also obtained. As a result, the California Utilities expect to install capital facilities starting in 2005, in order to receive natural gas supplies from new delivery locations. The CPUC has determined that project developers, not the utilities, will be presumed to pay for the costs for access-related infrastructure, subject to future applications to be filed when more is known about the particular projects. Note 5 of the notes to Consolidated Financial Statements herein provides further details.

Under terms of a franchise agreement and Memorandum of Understanding reached in October 2004 between SDG&E and the City of Chula Vista, the company has committed to support at the CPUC for undergrounding a part of the proposed Otay Mesa transmission line through Chula Vista's bayfront, upon CPUC approval of a substation upgrade, and replacement of certain other overhead transmission lines with underground facilities. Other transmission lines are to be undergrounded pursuant to the tariff Rule 20A undergrounding program. If the Otay Mesa undergrounding project is approved by the CPUC, the company's expected share of cost will be $36 million. If the company does not complete the undergrounding project by April 2010, there will not be an automatic renewal of the franchise at the end of the initial ten-year term.

CASH FLOWS FROM FINANCING ACTIVITIES

Net cash used in financing activities totaled $260 million and $204 million for the nine months ended September 30, 2004 and 2003, respectively. The change was due to higher dividends paid to Sempra Energy in 2004.

FACTORS INFLUENCING FUTURE PERFORMANCE

Performance of the company will depend primarily on the ratemaking and regulatory process, electric and natural gas industry restructuring, and the changing energy marketplace. These factors are discussed in the Annual Report and in Note 5 of the notes to Consolidated Financial Statements herein.

CRITICAL ACCOUNTING POLICIES AND KEY NON-CASH PERFORMANCE INDICATORS

There have been no significant changes to the accounting policies viewed by management as critical or key non-cash performance indicators for the company, as set forth in the Annual Report.

NEW ACCOUNTING STANDARDS

Relevant pronouncements that have recently become effective and have had a significant effect on the company are SFAS Nos. 132 (revised 2003), 143, 149 and 150, FASB Staff Position 106-2, and FIN 45 and 46, as discussed in Note 2 of the notes to Consolidated Financial Statements. Pronouncements that have or are likely to have a material effect on future earnings are described below.

SFAS 143, "*Accounting for Asset Retirement Obligations":* Beginning in 2003, SFAS 143 requires entities to record liabilities for future costs expected to be incurred when assets are retired from service, if the retirement process is legally required. It also requires the company to reclassify amounts recovered in rates for future removal costs not covered by a legal obligation from accumulated depreciation to a regulatory liability. Further discussion is provided in Note 2 of the notes to Consolidated Financial Statements.

In June 2004, the FASB issued a proposed interpretation of SFAS 143, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143.* The interpretation would clarify that a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of SFAS 143. Accordingly, the interpretation would require an entity to recognize a liability for a conditional asset retirement obligation if the liability's fair value can be reasonably estimated. The proposed interpretation would be effective for the company on December 31, 2005.

SFAS 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities*": SFAS 149 amends and clarifies accounting for derivative instruments and for hedging activities under SFAS 133. Under SFAS 149, natural gas forward contracts that are subject to unplanned netting do not qualify for the normal purchases and normal sales exception, whereby derivatives are not required to be marked to market when the contract is usually settled by the physical delivery of natural gas. The company has determined that all natural gas contracts are subject to unplanned netting and as such, these contracts are marked to market. In addition, effective January 1, 2004, power contracts that are subject to unplanned netting and that do not meet the normal purchases and normal sales exception under SFAS 149 are further marked to market. Implementation of SFAS 149 on July 1, 2003 did not have a material impact on reported net income.

ITEM 3. **QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

There have been no significant changes in the risk issues affecting the company subsequent to those discussed in the Annual Report.

As of September 30, 2004, the total Value at Risk of SDG&E's positions was not material.

ITEM 4. **CONTROLS AND PROCEDURES**

The company has designed and maintains disclosure controls and procedures to ensure that information required to be disclosed in the company's reports under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and is accumulated and communicated to the company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating these controls and procedures, management recognizes that any system of controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired objectives and necessarily applies judgment in evaluating the cost-benefit relationship of other possible controls and procedures.

Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, the company evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures as of September 30, 2004, 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.

There has been no change in the internal controls over financial reporting during the company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the company's internal controls over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. **LEGAL PROCEEDINGS**

SDG&E and the County of San Diego are continuing to negotiate the remaining terms of a settlement relating to alleged environmental law violations by SDG&E and its contractors in connection with the abatement of asbestos-containing materials during the demolition of a natural gas storage facility that was completed in 2001. The expected settlement would involve payments by SDG&E of less than $750,000.

Except as described above and in Notes 5 and 6 of the notes to Consolidated Financial Statements herein, neither the company nor its subsidiary is party to, nor is their property the subject of, any material pending legal proceedings other than routine litigation incidental to their businesses.

ITEM 6. **EXHIBITS AND REPORTS ON FORM 8-K**

(a) Exhibits

Exhibit 10 - Material Contracts

Compensation

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

10.2 Sempra Energy Amended and Restated Executive Life

Insurance Plan (September 30, 2004 Sempra Energy Form 10-Q Exhibit 10.2).

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

10.4 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).

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

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

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

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

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

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

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

Exhibit 12 - Computation of ratios

12.1 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.

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.

(b) Reports on Form 8-K

The following reports on Form 8-K were filed after June 30, 2004:

Current Report on Form 8-K filed August 5, 2004, filing as an exhibit Sempra Energy's press release of August 5, 2004, giving the financial results for the quarter ended June 30, 2004.

Current Report on Form 8-K filed September 30, 2004, announcing proposed decisions issued by the CPUC's Administrative Law Judge and the Assigned CPUC Commissioner on September 28, 2004, in the California Utilities' Cost of Service Proceedings.

Current Report on Form 8-K filed October 27, 2004, discussing the current status of the California Utilities' Cost of Service Proceedings and the Border Price Investigation.

Current Report on Form 8-K filed November 4, 2004, filing as an exhibit Sempra Energy's press release of November 4, 2004, giving the financial results for the quarter ended September 30, 2004.

SIGNATURE

Pursuant to the requirement 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)

Date: November 4, 2004 By: /s/ S. D. Davis

S. D. Davis
Sr. Vice President-External Relations
and Chief Financial Officer