THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
San Diego Gas & Electric Company	End of 2008/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules __________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent San Diego Gas & Electric Company	02 Year/Period of Report End of 2008/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 8330 Century Park Court, San Diego, California 92123	
05 Name of Contact Person Gregory D. Shimansky	06 Title of Contact Person Regulatory Reporting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 101 Ash Street, San Diego, California, 92101	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(619) 696-2347	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Robert M. Schlax	Robert M. Schlax	04/17/2009
02 Title VP, Controller & CFO		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	N/A
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	
55	Amounts included in ISO/RTO Settlement Statements	397	
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	N/A
63	Pumped Storage Generating Plant Statistics	408-409	N/A
64	Generating Plant Statistics Pages	410-411	N/A
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Four copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Robert M. Schlax, Vice President, Controller and Chief Financial Officer
8330 Century Park Court, San Diego, California 92123

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

California, April 6, 1905

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric and Natural Gas Services
State of California

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

The common stock of San Diego Gas & Electric (SDG&E) is owned 100% by Enova Corporation, the common stock of which is owned 100% by Sempra Energy.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 103 Line No.: 1 Column: a

SDG&E Funding LLC was dissolved in 2008. There was no gain or loss associated with this transaction.

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President & Chief Executive Officer*	Debra L. Reed	575,100
2	Chief Operating Officer*	Michael R. Niggli	453,000
3	Senior Vice President, Gas Operations*	Lee M. Stewart	333,800
4	Senior Vice President, Electric	James P. Avery	321,700
5	Senior Vice President, Customer Services*	Anne S. Smith	320,900
6	Senior Vice President, General Counsel*	w. Davis Smith	310,600
7	Senior Vice President of Regulatory & Finance*	Lee Schavrien	303,135
8	Vice President, Controller & Chief Financial Officer*	Robert M. Schlax	259,140
9	Treasurer*	Michael M. Schneider	176,088
10	Secretary*	Jennifer F. Jett	163,611
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26	CHANGES IN OFFICERS DURING 2008**		
27			
28	Senior Vice President & Chief Financial Officer-	Dennis V. Arriola	1,329,407
29	end 10/29/2008		
30			
31			
32			
33			
34	* These officers are shared with Southern California		
35	Gas Company.		
36			
37	**See page 109.1 for further details.		
38			
39			
40			
41			
42			
43			
44			

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Debra L. Reed, Chairperson, President & CEO	San Diego, CA
2	Michael R. Niggli, Chief Operating Officer	San Diego, CA
3	Mark A. Snell	San Diego, CA
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. None.

4. None.

5. SDG&E made various additions to its Electric Transmission system during 2008, the details of which are shown on pages 424-425.

   Pursuant to a California Public Utilities' Commission Decision issued in December 2007, effective April 1, 2008, the procurement of natural gas for SDG&E's core customers is administered by Southern California Gas Company.

6. SDG&E issued short term debt in the form of Commercial Paper during 2008. The average daily outstanding was $4.1 million with a maximum daily outstanding of $67.2 million. There was no commercial paper outstanding as of December 31, 2008.

7. None.

8. Based on terms reached in 2008 contract negotiations with the International Brotherhood of Electrical Workers (IBEW) Local 465, two increases to base wages were made for all employees in the bargaining unit on the effective dates.
   - Effective January 1, 2008, an increase of approximately 1% of annual base wage was implemented, affecting 1,714 employee for a total annualized base wage increase of approximately $1.1 million.
   - Effective September 1, 2008, an increase of approximately 3.6% of annual base wages was implemented, affecting 1,617 employees for a total annualized base wage increase of approximately $3.8 million.

9. Please refer to the Legal Proceeding section of the Notes to Financial Statement on pages 123.41.

10. None.

11. N/A.

12. Please refer to the Notes to Financial Statements beginning on page 123.1.

13. Changes in Officers:

Name	Title	Effective Date
Daniel F. Skopec	Vice President-Regulatory Affairs	Appointed January 02,2008
Pamela J. Fair	Vice President-Environmental, Safety, Facilities and Chief Environmental Officer	Title Change January 19, 2008
J. Bret Lane	Vice President-Gas Transmission and Distribution	Title Change January 19, 2008
Michelle M. Mueller	Vice President-Customer Operations	Title Change January 19, 2008
Richard M. Morrow	Vice President-Customer Services	Title Change January 19, 2008
Hal D. Snyder	Vice President-Customer Programs	Title Change January 19, 2008
Latimer Lorenz	Vice President-Regulatory Affairs-San Francisco	Resigned June 1, 2008
Patricia Wagner	Vice President-Operational Excellence	Appointed September 9, 2008
Dennis V. Arriola	Senior Vice President and Chief Financial Officer	Resigned October 29, 2008

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Lee Schavrien	Senior Vice President- Regulatory and Finance	Title Change October 30, 2008
Robert M. Schlax	Vice President, Controller and Chief Financial Officer	Title Change October 30, 2008

Changes in Directors:

None.

There have been no material changes to SDG&E’s stock ownership or voting power.

14. N/A.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	9,298,487,494	8,870,279,905
3	Construction Work in Progress (107)	200-201	412,030,658	278,253,380
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,710,518,152	9,148,533,285
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,403,390,271	4,217,223,939
6	Net Utility Plant (Enter Total of line 4 less 5)		5,307,127,881	4,931,309,346
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	6,480,420	18,623,925
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		97,538,885	68,199,160
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	62,819,937	50,142,988
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		41,199,368	36,680,097
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,348,327,249	4,967,989,443
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,849,836	3,678,303
19	(Less) Accum. Prov. for Depr. and Amort. (122)		481,512	442,999
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	3,290,000
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		602,013,834	740,241,709
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		8,855,847	1,505,557
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		616,238,005	748,272,570
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,502,232	23,099,930
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		3,000	50,866
38	Temporary Cash Investments (136)		0	120,196,911
39	Notes Receivable (141)		571,359	156,935
40	Customer Accounts Receivable (142)		179,709,688	162,017,417
41	Other Accounts Receivable (143)		30,146,627	49,164,851
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,941,518	2,355,836
43	Notes Receivable from Associated Companies (145)		38,405,829	4,950,475
44	Accounts Receivable from Assoc. Companies (146)		8,670,505	23,174,292
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	61,482,768	63,618,289
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		389,270	48,890,171
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		9,168	8,907
57	Prepayments (165)		35,299,547	69,166,536
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		31,399	11,160,695
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		48,868,000	47,394,000
62	Miscellaneous Current and Accrued Assets (174)		0	16,977,983
63	Derivative Instrument Assets (175)		47,976,067	28,383,908
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		8,855,847	1,505,557
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		446,268,094	664,550,773
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		20,093,163	21,023,623
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	8,990,296	10,882,990
72	Other Regulatory Assets (182.3)	232	1,500,943,026	1,097,092,395
73	Prelim. Survey and Investigation Charges (Electric) (183)		111,999,883	67,513,475
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-309,687	30,814
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	3,524,093	18,732,930
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		30,372,943	34,287,949
82	Accumulated Deferred Income Taxes (190)	234	257,111,803	207,058,974
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,932,725,520	1,456,623,150
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,343,558,868	7,837,435,936

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	291,458,395	291,458,395
3	Preferred Stock Issued (204)	250-251	78,475,400	78,475,400
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	592,222,753	592,222,753
7	Other Paid-In Capital (208-211)	253	279,618,042	279,618,042
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	25,688,571	25,688,571
11	Retained Earnings (215, 215.1, 216)	118-119	1,417,747,578	1,078,672,830
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-12,340,426	-15,469,094
16	Total Proprietary Capital (lines 2 through 15)		2,621,493,171	2,279,289,755
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,636,905,000	1,636,905,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	253,720,000	267,470,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		2,673,450	2,860,270
24	Total Long-Term Debt (lines 18 through 23)		1,887,951,550	1,901,514,730
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		29,242,420	31,402,167
29	Accumulated Provision for Pensions and Benefits (228.3)		423,712,775	194,167,078
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		273,188,885	310,909,998
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		2,237,580	1,853,839
34	Asset Retirement Obligations (230)		553,771,573	568,424,467
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,282,153,233	1,106,757,549
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		263,930,255	303,169,075
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		14,783,978	836,765
41	Customer Deposits (235)		52,675,790	51,723,308
42	Taxes Accrued (236)	262-263	2,779,807	1,781,842
43	Interest Accrued (237)		22,825,875	15,576,335
44	Dividends Declared (238)		1,204,917	1,204,917
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Rresubmission	04/17/2009	end of 2008/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		8,514,567	2,893,269
48	Miscellaneous Current and Accrued Liabilities (242)		214,666,461	187,059,145
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		335,032,279	369,487,812
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		273,188,885	310,909,998
52	Derivative Instrument Liabilities - Hedges (245)		2,237,580	1,853,839
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		2,237,580	1,853,839
54	Total Current and Accrued Liabilities (lines 37 through 53)		643,225,044	622,822,470
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		19,443,844	23,926,275
57	Accumulated Deferred Investment Tax Credits (255)	266-267	26,357,509	28,482,509
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	175,846,371	155,443,594
60	Other Regulatory Liabilities (254)	278	820,463,834	1,068,596,976
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	5,201,256	5,201,256
63	Accum. Deferred Income Taxes-Other Property (282)		624,480,776	521,157,360
64	Accum. Deferred Income Taxes-Other (283)		236,942,280	124,243,462
65	Total Deferred Credits (lines 56 through 64)		1,908,735,870	1,927,051,432
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,343,558,868	7,837,435,936

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,306,909,632	2,914,453,325		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,232,253,712	1,906,566,309		
5	Maintenance Expenses (402)	320-323	140,602,207	146,020,378		
6	Depreciation Expense (403)	336-337	278,379,365	282,148,811		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	17,473,268	16,915,603		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	15,744	15,744		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,892,694	1,892,694		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	68,707,433	62,963,374		
15	Income Taxes - Federal (409.1)	262-263	16,295,075	132,695,587		
16	- Other (409.1)	262-263	26,813,900	45,935,868		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	232,044,540	64,358,191		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	120,827,173	93,227,718		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,125,000	-2,800,000		
20	(Less) Gains from Disp. of Utility Plant (411.6)		3,157,081	1,875,781		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,888,368,684	2,561,609,060		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		418,540,948	352,844,265		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
2,613,997,462	2,239,776,792	700,031,126	677,604,226	-7,118,956	-2,927,693	2
						3
1,662,120,577	1,346,146,968	577,252,091	563,347,034	-7,118,956	-2,927,693	4
130,751,876	134,850,990	9,850,331	11,169,388			5
242,397,996	239,740,269	35,981,369	42,408,542			6
						7
14,516,851	13,880,945	2,956,417	3,034,658			8
15,744	15,744					9
1,892,694	1,892,694					10
						11
						12
						13
52,832,991	48,072,403	15,874,442	14,890,971			14
10,695,416	113,046,234	5,599,659	19,649,353			15
22,373,938	39,592,394	4,439,962	6,343,474			16
206,185,204	56,799,901	25,859,336	7,558,290			17
106,464,602	74,756,504	14,362,571	18,471,214			18
-1,450,000	-2,200,000	-675,000	-600,000			19
3,157,081			1,875,781			20
						21
						22
						23
						24
2,232,711,604	1,917,082,038	662,776,036	647,454,715	-7,118,956	-2,927,693	25
381,285,858	322,694,754	37,255,090	30,149,511			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		418,540,948	352,844,265		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		70,836	463,459		
35	Nonoperating Rental Income (418)		394,501	411,774		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		14,097,980	28,946,576		
38	Allowance for Other Funds Used During Construction (419.1)		27,319,884	16,773,673		
39	Miscellaneous Nonoperating Income (421)		1,553,716	2,791,079		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		43,295,245	48,459,643		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	578,920	1,702,928		
46	Life Insurance (426.2)		-2,948,849	-2,925,512		
47	Penalties (426.3)		2,542	8,411		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		21,500	21,000		
49	Other Deductions (426.5)		-67,500	260,522		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-2,413,387	-932,651		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	313,437	318,039		
53	Income Taxes-Federal (409.2)	262-263	-2,124,328	-1,863,460		
54	Income Taxes-Other (409.2)	262-263	-1,038,294	-2,176,434		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,938,012	2,458,264		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	-165,819	222,554		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,254,646	-1,486,145		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		44,453,986	50,878,439		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		97,025,854	88,052,494		
63	Amort. of Debt Disc. and Expense (428)		1,462,518	1,624,755		
64	Amortization of Loss on Reaquired Debt (428.1)		3,915,007	4,206,119		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340		1,979,164		
68	Other Interest Expense (431)	340	26,768,878	26,777,270		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,071,740	6,642,159		
70	Net Interest Charges (Total of lines 62 thru 69)		119,100,517	115,997,643		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		343,894,417	287,725,061		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		343,894,417	287,725,061		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 2 Column: c

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 2 Column: d

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 2 Column: k

Eliminates amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 2 Column: l

Eliminates amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 4 Column: c

Total Operation Revenues excludes amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 4 Column: d

Total Operation Expenses excludes amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 4 Column: k

Eliminates amounts associated with interdepartmental transfers.

Schedule Page: 114 Line No.: 4 Column: l

Eliminates amounts associated with interdepartmental transfers.

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,078,672,830	797,169,413
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adoption of FIN 48 Adjustment			(1,401,975)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(1,401,975)
16	Balance Transferred from Income (Account 433 less Account 418.1)		343,894,417	287,725,061
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24		238	-4,819,669	(4,819,669)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-4,819,669	(4,819,669)
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,417,747,578	1,078,672,830
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,417,747,578	1,078,672,830
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	343,894,417	287,725,061
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	278,379,365	282,148,811
5	Amortization of Utility Acquisition Adjustment, Property Losses, &		
6	Unrecovered Plant and Regulatory Study Costs	19,381,706	18,824,041
7			
8	Deferred Income Taxes (Net)	100,391,489	-26,633,817
9	Investment Tax Credit Adjustment (Net)	-2,125,000	-2,800,000
10	Net (Increase) Decrease in Receivables	15,526,999	-31,736,090
11	Net (Increase) Decrease in Inventory	50,636,160	-15,724,298
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-18,043,668	-8,896,695
14	Net (Increase) Decrease in Other Regulatory Assets	-149,946,289	107,492,548
15	Net Increase (Decrease) in Other Regulatory Liabilities	-122,828,742	95,306,085
16	(Less) Allowance for Other Funds Used During Construction	27,319,884	16,773,673
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: Net (increase) Decrease in Prepayment & Other	50,845,072	-23,233,032
19	Net increase (decrease) in Accrued Interest & Taxes	31,195,413	5,040,855
20	Other - net	80,825,200	-21,264,251
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	650,812,238	649,475,545
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-714,987,168	-626,340,372
27	Gross Additions to Nuclear Fuel	-17,196,219	-17,421,628
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-27,319,884	-16,773,673
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-704,863,503	-626,988,327
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	721,417	1,911,898
38	Gain on Sale of Noncurrent Assets	-3,157,081	-1,875,781
39	Investments in and Advances to Assoc. and Subsidiary Companies	-30,165,353	-240,065
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-24,000,000	
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Decommissioning Trust Fund Distribution	-9,350,000	-9,128,082
54	Other: Decommissioning Trust Fund Withdrawal	9,457,552	13,945,345
55	Other: Increase (decrease) in Customer Advances for Construction	-6,728,076	-4,807,157
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-768,085,044	-627,182,169
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		250,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		-72,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)		178,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-58,804,288
74	Preferred Stock	-13,750,000	-2,500,000
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-4,819,669	-4,819,669
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-18,569,669	111,876,043
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-135,842,475	134,169,419
87			
88	Cash and Cash Equivalents at Beginning of Period	143,347,707	9,178,288
89			
90	Cash and Cash Equivalents at End of period	7,505,232	143,347,707

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Notes for Statement of Cash Flows:

Supplemental Disclosure of Cash Flow Information:

Income tax payments, net of refunds	$3,333,763
Interest payments, net of amounts capitalized	92,789,071

Reconciliation of Cash and Cash Equivalents at December 31, 2008:

Account 131	Cash	$7,502,232
Account 135	Working Funds	3,000
		$7,505,232

Supplemental Disclosure of Non-Cash Investing Activity:

Increase in accounts payable from investments In property, plant and equipment	$21,723,000

2. Basis of Presentation and Notes to Financial Statements:

Beginning on page 123.2 are excerpts from Sempra Energy's (Sempra or the parent) Annual Report on Form 10-K for the period ending December 31, 2008, as filed with the Securities and Exchange Commission (SEC) on February 24, 2009. The following disclosures contain information in accordance with SEC requirements.

These financial statements, included on pages 110 through 122b of this report, were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in the applicable Uniform System of Accounts and published accounting releases. Such requirements and published accounting releases constitute a comprehensive basis of accounting other than Accounting Principals Generally Accepted in the United States of America (GAAP). The principal differences of this basis of accounting from GAAP include, but are not necessarily limited to, the accounting for and classification of:

- Certain deferred income taxes and regulatory assets and liabilities
- Certain assets and liabilities between current and non-current
- Nuclear property, certain cost of removal obligations, and property reserves
- Gains and losses on nuclear decommissioning trust fund activities
- Generation turnkey projects
- Mandatorily redeemable preferred securities
- Classification of interest and penalties associated with income taxes
- Certain revenues net of related costs
- Majority-owned subsidiaries on an equity basis
- Consolidation of variable interest entities (VIE) under FIN46R

SDG&E's Notes to the Financial Statements on the following pages include information related to its subsidiary, SDG&E Funding LLC, and a VIE, Otay Mesa Energy Center LLC, and are prepared in conformity with GAAP on a consolidated basis. Accordingly, certain Notes to the Financial Statements are not reflective of SDG&E's Financial Statements contained herein, which have been prepared on a stand alone basis, which excludes consolidation with SDG&E Funding LLC or Otay Mesa Energy Center LLC's Financial Statements.

Due to the differences between FERC and SEC reporting requirements as mentioned above, certain amounts disclosed in the following notes may not agree to balances in the FERC financial statements.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

PRINCIPLES OF CONSOLIDATION

SDG&E's Consolidated Financial Statements include its accounts and the accounts of 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. The activities of SDG&E Funding LLC were substantially complete in 2007, and the entity was dissolved in 2008.

BASIS OF PRESENTATION

References in this report to "we" and "our" are to SDG&E and its consolidated entities, unless otherwise indicated by the context. We have eliminated intercompany accounts and transactions within each set of consolidated financial statements.

USE OF ESTIMATES IN THE PREPARATION OF THE FINANCIAL STATEMENTS

We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP). This requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes, including the disclosure of contingent assets and liabilities at the date of the financial statements. Although we believe the estimates and assumptions are reasonable, actual amounts ultimately may differ significantly from those estimates.

REGULATORY MATTERS

Effects of Regulation

The accounting policies of SDG&E conform with GAAP for regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

SDG&E 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 SFAS 71, 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 are written off. Regulatory liabilities represent amounts collected from customers in advance of the actual expenditure by the utility. If the actual expenditures are less than amounts previously collected from ratepayers, the excess would be refunded to customers, generally by reducing future rates.

We provide information concerning regulatory assets and liabilities below in "Regulatory Balancing Accounts" and "Regulatory Assets and Liabilities."

Regulatory Balancing Accounts

The following table summarizes our regulatory balancing accounts at December 31. The net payables (payables net of receivables) will be returned to customers by reducing future rates.

	SDG&E	
	2008	2007
Over-collected	$ 364	$ 455
Under-collected	(250)	(157)
Net payable	$ 114	$ 298

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Over- and under-collected regulatory balancing accounts reflect the difference between customer billings and recorded or CPUC-authorized costs, primarily commodity costs. Amounts in the balancing accounts are recoverable or refundable in future rates, subject to CPUC approval. Balancing account treatment eliminates the impact on earnings from variances in the covered costs from authorized amounts. Absent balancing account treatment, variations in operating and maintenance costs from amounts approved by the CPUC may increase volatility in utility earnings.

We provide additional information about regulatory matters in Notes 10 and 11.

Regulatory Assets and Liabilities

We show the details of regulatory assets and liabilities in the following table, and discuss each of them separately below.

REGULATORY ASSETS AND LIABILITIES AT DECEMBER 31
(Dollars in millions)

	2008	2007
SDG&E		
Fixed-price contracts and other derivatives	$ 358	$ 361
Deferred taxes recoverable in rates	369	312
Unamortized loss on reacquired debt, net	30	34
Pension and other postretirement benefit obligations	393 **	162
Removal obligations*	(1,212)	(1,335)
Environmental costs	21	11
Other	16	17
Total SDG&E	(25)	(438)

* *This is related to SFAS 143, Accounting for Asset Retirement Obligations, which we discuss below in "Asset Retirement Obligations."*

** *Recent market turmoil resulted in significant losses in the value of assets in pension and postretirement benefit plans. At SDG&E, the impact of this loss in value is recoverable in rates, which caused an increase in regulatory assets for pension and other postretirement benefit plans in 2008.*

NET REGULATORY ASSETS (LIABILITIES) AS PRESENTED ON THE CONSOLIDATED BALANCE SHEETS AT DECEMBER 31
(Dollars in millions)

	2008	2007
Current regulatory assets	$ 102	$ 66
Noncurrent regulatory assets	1,085	831
Current regulatory liabilities*	--	--
Noncurrent regulatory liabilities	(1,212)	(1,335)
Total	$ (25)	$ (438)

* *Included in Other Current Liabilities.*

In the tables above:

- 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 commodities and services under these contracts.
- Deferred taxes recoverable/refundable in rates are based on current regulatory ratemaking and income tax laws. SDG&E expects to recover/refund net regulatory assets/liabilities related to deferred income taxes over the lives of the assets that give rise to the accumulated deferred income tax liabilities/assets.
- Regulatory assets related to unamortized losses on reacquired debt are recovered over the remaining original amortization periods of the loss on reacquired debt. These periods range from 3 months to 19 years for SDG&E.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

- Regulatory assets related to environmental costs represent the portion of our environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. We expect this amount to be recovered in future rates as expenditures are made.
- Regulatory assets related to pension and other postretirement benefit obligations are offset by corresponding liabilities and are being recovered in rates as the costs are incurred.

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.

FAIR VALUE MEASUREMENTS

We apply recurring fair value measurements to certain assets and liabilities, primarily nuclear decommissioning trusts, marketable securities and other miscellaneous derivatives. The valuation techniques we use to determine fair value are in accordance with SFAS 157, *Fair Value Measurements* (SFAS 157).

SFAS 157 defines "fair value" as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

SFAS 157 requires that a fair value measurement reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risk inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model. SFAS 157 also clarifies that an issuer's credit standing should be considered when measuring liabilities at fair value.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 financial instruments primarily consist of exchange-traded derivatives, listed equities and U.S. government treasury securities.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including:

- quoted forward prices for commodities
- time value
- volatility factors
- current market and contractual prices for the underlying instruments
- other relevant economic measures

Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Our financial instruments in this category include non-exchange-traded derivatives such as over-the-counter (OTC) forwards and options.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value from the perspective of a market participant.

We elected to early-adopt SFAS 157 in the first quarter of 2007. As required, we applied the provisions of SFAS 157 prospectively, except for the initial impact of certain items specified by the pronouncement.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

As required under SFAS 157, we would have recorded the adjustments for these items as a transition adjustment to beginning retained earnings in 2007. There was no transition adjustment as a result of the adoption of SFAS 157 at SDG&E.

CASH AND CASH EQUIVALENTS

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

COLLECTION ALLOWANCES

We record allowances for the collection of receivables. The allowances for collection of receivables include allowances for doubtful customer accounts and for other receivables. The changes in allowances for collection of receivables and realization of trading assets are shown in the table below:

COLLECTION ALLOWANCES
(Dollars in millions)

	Years ended December 31, 2008	2007	2006
SDG&E			
Allowances for collection of receivables at January 1	$ 5	$ 5	$ 4
Provisions for uncollectible accounts	12	8	9
Write-offs of uncollectible accounts	(11)	(8)	(8)
Allowances for collection of receivables at December 31	$ 6	$ 5	$ 5

INVENTORIES

SDG&E values natural gas inventory by the last-in first-out (LIFO) method. As inventories are sold, differences between the LIFO valuation and the estimated replacement cost are reflected in customer rates. Materials and supplies at SDG&E are generally valued at the lower of average cost or market.

INVENTORY BALANCES AT DECEMBER 31
(Dollars in millions)

	SDG&E 2008	SDG&E 2007
Natural gas	$ --	$ 49
Materials and supplies	62	64
Total	$ 62	$ 113

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), we record deferred income taxes for temporary differences between the book and the tax bases of assets and liabilities. Investment tax credits from prior years are amortized to income by SDG&E over the estimated service lives of the properties as required by the CPUC.

We follow certain provisions of SFAS 109 that require regulated enterprises to recognize:

- regulatory assets to offset deferred tax liabilities if it is probable that the amounts will be recovered from customers; and

- regulatory liabilities to offset deferred tax assets if it is probable that the amounts will be returned to customers.

We also follow:

- Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* (FIN 48).

We provide additional information about income taxes in Note 5.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment primarily represents the buildings, equipment and other facilities used by SDG&E to provide natural gas and electric utility services. It also reflects projects included in construction work in progress at these business units.

Our plant costs include:

- labor
- materials and contract services
- expenditures for replacement parts incurred during a major maintenance outage of a generating plant

Maintenance costs are expensed as incurred. The cost of most retired depreciable utility plant minus salvage value is charged to accumulated depreciation.

The cost of our utility plant includes an allowance for funds used during construction (AFUDC). AFUDC is discussed below. The cost of non-utility plant includes capitalized interest.

PROPERTY, PLANT AND EQUIPMENT BY MAJOR FUNCTIONAL CATEGORY
(Dollars in billions)

	Property, Plant and Equipment at December 31,		Depreciation rates for years ended December 31,		
	2008	2007	2008	2007	2006
SDG&E:					
Natural gas operations	$ 1.1	$ 1.1	2.80 %	3.43 %	3.42 %
Electric distribution	4.2	4.0	3.95	4.15	4.13
Electric transmission	1.5	1.4	2.67	2.84	3.07
Electric generation	0.9	0.8	3.77	3.67	4.44
Other electric	0.5	0.5	8.13	8.50	8.70
Construction work in progress	0.9	0.5	NA	NA	NA
Total SDG&E	9.1	8.3			

Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. The accumulated depreciation and decommissioning amounts on our Consolidated Balance Sheets are as follows:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

ACCUMULATED DEPRECIATION AND DECOMMISSIONING AMOUNTS
(Dollars in billions)

	At December 31, 2008	2007
SDG&E:		
Accumulated depreciation and decommissioning of utility plant in service:		
Electric	$ 1.9	$ 1.8
Natural gas	0.5	0.5
Total SDG&E	2.4	2.3

SDG&E finances its construction projects with borrowed funds and equity funds. The CPUC allows the recovery of the cost of these funds as part of the cost of construction projects by recording AFUDC, which is calculated using rates authorized by the CPUC. SDG&E recovers the AFUDC from its customers, plus earns a return on the allowance after the utility property is placed in service.

CAPITALIZED FINANCING COSTS
(Dollars in millions)

	Years ended December 31, 2008	2007	2006
SDG&E:			
AFUDC related to debt	$ 10	$ 7	$ 5
AFUDC related to equity	27	17	10
Other capitalized financing costs	13	3	1
Total SDG&E	50	27	16

ASSETS HELD FOR SALE

We classify assets as held for sale when management approves and commits to a formal plan to actively market an asset for sale and the sale is expected to close within the next twelve months. Upon classifying an asset as held for sale, we record the asset at the lower of its carrying value or its estimated fair value reduced for selling costs. We cease to record depreciation expense on an asset when it is classified as held for sale.

LONG-LIVED ASSETS

In accordance with SFAS 144, *Accounting for the Impairment or Disposal of Long-lived Assets* (SFAS 144), we periodically evaluate whether events or circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets, the definition of which includes intangible assets subject to amortization in accordance with SFAS 142, but does not include unconsolidated subsidiaries. Impairment of long-lived assets occurs when the estimated future undiscounted cash flows are less than the carrying amount of the assets. If that comparison indicates that the assets' carrying value may be permanently impaired, the potential impairment is measured based on the difference between the carrying amount and the fair value of the assets. This calculation is performed at the lowest level for which separately identifiable cash flows exist.

ASSET RETIREMENT OBLIGATIONS

We account for tangible long-lived assets in accordance with SFAS 143, *Accounting for Asset Retirement Obligations* (SFAS 143), and FIN 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* (FIN 47). SFAS 143 and FIN 47 require us 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. We record 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 record regulatory assets or liabilities as a result of the timing difference between the recognition of costs as recorded in accordance

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

with SFAS 143 and FIN 47, and costs recovered through the rate-making process. We have recorded a regulatory liability to show that SDG&E has collected funds from customers more quickly and for larger amounts than SFAS 143 and FIN 47 would accrete the retirement liability and depreciate the asset.

We have recorded asset retirement obligations related to various assets including:

- fuel and storage tanks
- natural gas distribution system
- hazardous waste storage facilities
- asbestos-containing construction materials
- decommissioning of nuclear power facilities
- electric distribution and transmission systems
- site restoration of a former power plant

The changes in asset retirement obligations are as follows:

CHANGES IN ASSET RETIREMENT OBLIGATIONS
(Dollars in millions)

	SDG&E December 31, 2008	SDG&E December 31, 2007
Balance as of January 1	$ 568	$ 483
Accretion expense	37	35
Liabilities incurred	--	1
Payments	(10)	(20)
Revision to estimated cash flows	(41)	69
Additions	--	--
Acquisition of EnergySouth (see Note 3)	--	--
Balance as of December 31	$ 554	$ 568

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
- changes in minimum pension liability
- certain hedging activities

The Statements of Consolidated Comprehensive Income and Changes in Shareholders' Equity show the changes in the components of other comprehensive income. The components of Accumulated Other Comprehensive Income (Loss), shown net of income taxes, and the related income tax expense (benefit) at December 31, 2008 and 2007 are as follows:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) AND ASSOCIATED INCOME TAX EXPENSE (BENEFIT)
(Dollars in millions)

	Accumulated Other Comprehensive Income (Loss)		Income Tax Expense (Benefit)	
	2008	2007	2008	2007
SDG&E				
Unamortized net actuarial loss	$ (13)	$ (16)	$ (8)	$ (11)
Unamortized prior service credit	1	1	1	1
Financial instruments	(1)	(1)	(1)	(1)
Balance as of December 31	$ (13)	$ (16)	$ (8)	$ (11)

REVENUES

SDG&E generates revenues primarily from deliveries to its customers of electricity and natural gas and from related services. It records these revenues under the accrual method and recognizes them upon delivery and performance. SDG&E also records revenues from incentive awards, which is recognized upon approval of the award by the CPUC. We provide additional discussion on utility incentive awards in Note 7.

Under an operating agreement with the California Department of Water Resources (DWR), SDG&E acts as a limited agent on behalf of the DWR in the administration of energy contracts, including natural gas procurement functions under the DWR contracts allocated to SDG&E's customers. The legal and financial responsibilities associated with these activities continue to reside with the DWR. Therefore, the 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 our Statements of Consolidated Income. We provide discussion on electric industry restructuring related to the DWR in Note 10.

The table below shows the total revenues from SDG&E’s Statement of Consolidated Income, which are net of sales taxes, for each of the last three years. The revenues include amounts for services rendered but unbilled (approximately one-half month's deliveries) at the end of each year.

TOTAL SDG&E REVENUES
(Dollars in millions)

	Years ended December 31,		
	2008	2007	2006
Natural gas revenues	$ 689	$ 658	$ 638
Electric revenues	2,562	2,194	2,147
Total	$ 3,251	$ 2,852	$ 2,758

* *Excludes intercompany revenues.*

As discussed in Note 11, beginning April 1, 2008, the SDG&E and SoCalGas (an affiliate utility) core natural gas supply portfolios were combined and are managed by SoCalGas. Effective as of that date, SoCalGas procures natural gas for SDG&E’s core customers. Core customers are primarily residential and small commercial and industrial customers. This core gas procurement function is considered a shared service.

We provide additional information concerning utility revenue recognition in "Regulatory Matters" above.

OPERATION AND MAINTENANCE EXPENSES

Operation and Maintenance includes operating and maintenance costs, and general and administrative costs, which consist primarily of personnel costs, purchased materials and services, and rent.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

TRANSACTIONS WITH AFFILIATES

SDG&E provides certain services to its parent company and its other affiliate utility, which are charged an allocable share of the cost of such services. Amounts due to/from affiliates are as follows:

AMOUNTS DUE TO AND FROM AFFILIATES AT SDG&E
(Dollars in millions)

	December 31, 2008	December 31, 2007
SDG&E		
Current:		
Due from Sempra Energy	$ 20	$ --
Due from SoCalGas	8	21
Due from various affiliates	1	1
	$ 29	$ 22
Due to various affiliates	$ 1	$ 1
Due to Sempra Energy	--	9
	$ 1	$ 10
Income taxes due to (from) Sempra Energy*	$ 7	$ (38)
Noncurrent:		
Promissory note due from Sempra Energy, variable rate based on short-term commercial paper rate (0.12% at December 31, 2008)	$ 4	$ 5

* *SDG&E is included in the consolidated income tax return of Sempra Energy and are 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.*

Revenues from unconsolidated affiliates at SDG&E are as follows:

REVENUES FROM UNCONSOLIDATED AFFILIATES AT SDG&E
(Dollars in millions)

	2008	2007	2006
SDG&E	$ 11	$ 13	$ 15

DIVIDENDS AND LOANS AT SDG&E

The CPUC's regulation of SDG&E's capital structures limits the amounts that are available for dividends and loans to Sempra Energy. At December 31, 2008, SDG&E could have provided a total of approximately $150 million to Sempra Energy through dividends and loans.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

OTHER INCOME (EXPENSE), NET

Other Income (Expense), Net on the Statements of Consolidated Income consists of the following:

OTHER INCOME (EXPENSE), NET *(Dollars in millions)*	Years ended December 31,		
	2008	2007	2006
SDG&E			
Allowance for equity funds used during construction	$ 27	$ 17	$ 10
Regulatory interest, net	(5)	(7)	(3)
Sundry, net	3	1	1
Total	$ 25	$ 11	$ 8

NOTE 2. NEW ACCOUNTING STANDARDS

We describe below recent pronouncements that have had or may have a significant effect on our financial statements. We do not discuss recent pronouncements that are not anticipated to have a significant impact on or are unrelated to our financial condition, results of operations, or disclosures.

SFAS 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (SFAS 161): SFAS 161 expands the disclosure requirements in SFAS 133*, Accounting for Derivative Instruments and Hedging Activities (SFAS 133)*.

SFAS 161 requires disclosures about the following:

- qualitative objectives and strategies for using derivatives;
- quantitative disclosures of fair value amounts, and gains and losses on derivative instruments and related hedged items; and
- credit-risk-related contingent features in derivative agreements.

SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Our 2009 financial statements will include the additional disclosures.

SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51" (SFAS 160): SFAS 160 amends Accounting Research Bulletin (ARB) No. 51, *Consolidated Financial Statements*, to establish accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent.

SFAS 160 provides guidance on the following:

- how to report non-controlling interests in a subsidiary in consolidated financial statements;
- the amount of consolidated net income attributable to the parent and to the non-controlling interest; and
- changes in a parent's ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated.

The pronouncement also requires disclosures that clearly identify and distinguish between the interest of the parent and the interests of the non-controlling owners. SFAS 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and early adoption is prohibited. SFAS 160 must be applied prospectively, except for presentation and disclosure requirements for existing minority interests. These requirements must be applied retrospectively. Our 2009 financial statements will include the adoption of SFAS 160.

SFAS 141 (revised 2007), "Business Combinations" (SFAS 141(R)): SFAS 141(R) applies to all transactions or events in which an entity obtains control of one or more businesses, including those combinations achieved without transfer of consideration. In the

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

context of a business combination, SFAS 141(R) establishes principles and requirements for how the acquirer recognizes the following:

- assets acquired, including goodwill
- assumed liabilities
- non-controlling interest in the acquired entity
- contractual contingencies
- contingent consideration

SFAS 141(R) requires that the acquirer in a business combination achieved in stages recognize identifiable assets and liabilities at the full amounts of their fair values. This statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effect of the business combination. SFAS 141(R) applies to us for business combinations with an acquisition date on or after January 1, 2009. Early adoption is prohibited.

FASB Staff Position (FSP) FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP FAS 132(R)-1): FSP FAS 132(R)-1 requires disclosure about the assets held in postretirement benefit plans, including a breakdown by the level of the assets and a reconciliation of any change in Level 3 assets during the year. It requires that disclosures include information about the following:

- valuation inputs, with detailed disclosure required about Level 3 assets
- asset categories, broken down to relevant detail
- concentration of risk in plan assets

FSP FAS 132(R)-1 applies prospectively for fiscal years ending after December 15, 2009. Early application is permitted. We are in the process of evaluating the effect of this statement on our financial statement disclosures.

FSP FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FSP FAS 140-4 and FIN 46(R)-8): This FSP amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, to require additional disclosure about transfers of financial assets and variable interests in qualifying special-purpose entities. It also amends FIN 46(R) to require certain disclosures about an entity's involvement with variable interest entities, as follows:

- details of the entity's involvement (both explicit and implicit arrangements) with the variable interest entity
- financial or other support provided to the variable interest entity which was not contractually required and the primary reasons for providing the support
- the methodology for determining the primary beneficiary and any changes in prior consolidation conclusions
- the terms of any arrangements (both explicit and implicit) that could require the primary beneficiary to provide financial support to the variable interest entity

This FSP is effective for fiscal years ending after December 15, 2008. We provide the additional required disclosure in Note 1.

FSP FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" (FSP FAS 157-3): FSP FAS 157-3 clarifies and illustrates the application of SFAS 157 for financial assets in an inactive market. It became effective when issued on October 10, 2008 and applied to periods for which financial statements had not yet been issued. Revisions to the fair value estimates resulting from the adoption of the FSP are to be accounted for as a change in estimate, so that any effects on the fair value measurements would be recognized in the period of adoption. Our application of FSP FAS 157-3 impacted neither financial asset fair values nor their classification in the fair value hierarchy. Additional disclosure is provided in Note 8.

FSP FIN 39-1, "Amendment of FASB Interpretation No. 39" (FSP FIN 39-1): FSP FIN 39-1 amends certain paragraphs of FIN No. 39, *Offsetting of Amounts Related to Certain Contracts*, to permit an entity to report all derivatives recorded at fair value on the balance sheet net of any associated fair value cash collateral when the derivative and cash collateral are with the same counterparty under a master netting arrangement. We adopted FSP FIN 39-1 effective January 1, 2008. We applied FSP FIN 39-1 as a change in accounting principle. The consolidated balance sheets herein reflect the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when management believes a legal right of setoff exists.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 3. DEBT AND CREDIT FACILITIES

COMMITTED LINES OF CREDIT

SDG&E and its affiliate, SoCalGas, have a combined $800 million, three-year syndicated revolving credit agreement expiring in 2011. JPMorgan Chase Bank serves as administrative agent for the syndicate of 17 lenders. No single bank has greater than a 9.9 percent share. The agreement permits each utility to individually borrow up to $600 million, subject to a combined limit of $800 million for both utilities. It also provides for the issuance of letters of credit on behalf of each utility subject to a combined letter of credit commitment of $200 million for both utilities. The amount of borrowings otherwise available under the facility is reduced by the amount of outstanding letters of credit.

Borrowings under the facility bear interest at benchmark rates plus a margin that varies with market index rates and the borrowing utility's credit rating. The agreement also requires SDG&E to maintain a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 65% at the end of each quarter.

SDG&E’s obligations under the agreement are individual obligations, and a default by one utility would not constitute a default by the other utility or preclude borrowings by, or the issuance of letters of credit on behalf of, the other utility.

At December 31, 2008, SDG&E had no outstanding borrowings under this facility. SDG&E had $110 million of outstanding letters of credit and $237 million of variable-rate demand notes outstanding supported by this facility at December 31, 2008.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

LONG-TERM DEBT

The following tables show the detail and maturities of long-term debt outstanding:

LONG-TERM DEBT
(Dollars in millions)

	December 31, 2008	December 31, 2007
SDG&E		
First mortgage bonds:		
6.8% June 1, 2015	$ 14	$ 14
5.3% November 15, 2015	250	250
Variable rate (1% at December 31, 2008) July 2018 (1)	161	161
5.85% June 1, 2021 (1)	60	60
6% June 1, 2026	250	250
5% to 5.25% December 1, 2027 (1)	150	150
2.516% to 2.832% January and February 2034 (1) (2)	176	176
5.35% May 15, 2035	250	250
6.125% September 15, 2037	250	250
Variable rate (1.45% at December 31, 2008) May 1, 2039 (1)	75	75
	1,636	1,636
Other long-term debt (unsecured, unless otherwise noted):		
5.9% June 1, 2014	130	130
5.3% July 1, 2021 (1)	39	39
5.5% December 1, 2021 (1)	60	60
4.9% March 1, 2023 (1)	25	25
OMEC LLC project financing at 6.2% payable 2009 through April 2019 (secured by project assets) (3)	256	63
Other	--	7
	510	324
	2,146	1,960
Current portion of long-term debt	(2)	--
Unamortized discount on long-term debt	(2)	(2)
Total SDG&E	2,142	1,958

(1) Callable long-term debt.
(2) After floating-to-fixed rate swaps expiring in 2009.
(3) After floating-to-fixed rate swaps expiring in 2019.

MATURITIES OF LONG-TERM DEBT*
(Dollars in millions)

	SDG&E
2009	$ 2
2010	7
2011	7
2012	7
2013	7
Thereafter	2,116
Total	$ 2,146

* *Excludes market value adjustments for interest-rate swaps.*

Various long-term obligations totaling $254 million at SDG&E at December 31, 2008, are unsecured.

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report 2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

CALLABLE LONG-TERM DEBT

At the option of SDG&E, certain debt is callable subject to premiums at various dates:

CALLABLE LONG-TERM DEBT
(Dollars in millions)

		SDG&E
2009	$	472
2010		--
2013		45
after 2013		229
Total	$	746
Callable bonds subject to make-whole provisions	$	1,000

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 their bond agreements (indentures). These indentures require, 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 $2.9 billion of first mortgage bonds at SDG&E at December 31, 2008.

INDUSTRIAL DEVELOPMENT BONDS

During 2008, Sempra Energy purchased $413 million of industrial development bonds, net of sales and purchases with SDG&E as the cash flow needs of each entity changed. SDG&E purchased $488 million of the bonds during 2008, and sold $228 million to Sempra Energy during 2008. The bonds were initially issued as insured, auction-rate securities, the proceeds of which were loaned to SDG&E, and are repaid with payments from SDG&E first mortgage bonds that have terms corresponding to those of the industrial development bonds that they secure.

In December 2008, SDG&E remarketed $237 million of these industrial development bonds. These included $75 million remarketed at an initial daily floating-rate of 0.65 percent (maturing in 2039), and $161 million remarketed for a three-month term at a rate of 1.00 percent (maturing in 2018). Beginning in March 2009, the interest rate on the $161 million series will be reset on a weekly basis.

The remaining industrial development bonds, $24 million held by SDG&E and $152 million held by Sempra Energy, are classified as available-for-sale securities and included in Short-Term Investments on the Consolidated Balance Sheets at December 31, 2008. Sempra Energy and SDG&E intend to remarket the remaining bonds in early 2009 and to modify the credit support and liquidity requirements of the remaining bonds in conjunction with their remarketing to investors.

DEBT OF EMPLOYEE STOCK OWNERSHIP PLAN (ESOP) AND TRUST (TRUST)

The ESOP covers substantially all Sempra Energy employees, including SDG&E. The Trust is used to fund part of the retirement savings plan described in Note 6. The notes of the ESOP are payable by the Trust and mature in 2014.

In July 2007, $50 million of these notes was repriced at an interest rate of 5.781 percent for a three-year term ending July 1, 2010. The remaining $22 million of the notes is repriced weekly and subject to repurchase at our option. ESOP debt was paid down by a total of $32 million during the last three years when 739,220 shares of Sempra Energy common stock were released from the Trust in order to fund employer contributions to the Sempra Energy savings plan trust. Interest on the ESOP debt amounted to $4 million in each of

2008, 2007 and 2006. Dividends used for debt service amounted to $2 million in each of 2008, 2007 and 2006.

INTEREST-RATE SWAPS

We discuss our fair value interest-rate swaps and interest-rate swaps to hedge cash flows in Note 8.

NOTE 4. FACILITIES UNDER JOINT OWNERSHIP

San Onofre Nuclear Generating Station (SONGS) and the Southwest Powerlink transmission line are owned jointly by SDG&E with other utilities. SDG&E’s interests at December 31, 2008 were as follows:

(Dollars in millions)	SONGS	Southwest Powerlink
Percentage ownership	20 %	91 %
Utility plant in service	$ 90	$ 314
Accumulated depreciation and amortization	22	176
Construction work in progress	113	7

SDG&E, and each of the other owners, holds its undivided interest as a tenant 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.

SDG&E’s share of operating expenses is included in its 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.

SDG&E's asset retirement obligation related to decommissioning costs for the SONGS units was $445 million at December 31, 2008. That amount includes the cost to decommission Units 2 and 3, and the remaining cost to complete the decommissioning of Unit 1, which is currently in progress. Southern California Edison updates decommissioning cost studies every three years. In January 2007, the CPUC approved the most recent update. 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.

Unit 1 was permanently shut down in 1992, and physical decommissioning began in January 2000. Most 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. Southern California Edison expects Phase I of decommissioning activities to be complete in the first quarter of 2009. The decommissioning of Unit 1 remaining structures (subsurface and intake/discharge) will take place when Units 2 & 3 are decommissioned. The ISFSI will be decommissioned after a permanent storage facility becomes available and the U.S. Department of Energy (DOE) removes the spent fuel from the site. The Unit 1 reactor vessel is expected to remain on site until Units 2 and 3 are decommissioned.

The amounts collected in rates for SONGS' decommissioning are invested in externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations. These trusts are shown on SDG&E Balance Sheets at fair value with the offsetting credits recorded in Asset Retirement Obligations and Regulatory Liabilities Arising from Removal Obligations.

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NUCLEAR DECOMMISSIONING TRUSTS
(Dollars in millions)

	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
As of December 31, 2008:				
Debt securities				
U.S. government issues*	$ 127	$ 28	$ --	$ 155
Municipal bonds**	69	1	(9)	61
Total debt securities	196	29	(9)	216
Equity securities	251	105	(36)	320
Cash and other securities***	40	3	(2)	41
Total available-for-sale securities	$ 487	$ 137	$ (47)	$ 577
As of December 31, 2007:				
Debt securities				
U.S. government issues	$ 168	$ 15	$ --	$ 183
Municipal bonds	77	1	(2)	76
Total debt securities	245	16	(2)	259
Equity securities	204	234	(4)	434
Cash and other securities	44	2	--	46
Total available-for-sale securities	$ 493	$ 252	$ (6)	$ 739

* *Maturity dates are* 2009-2038
** *Maturity dates are* 2009-2043
*** *Maturity dates are* 2009-2049

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

SALES OF SECURITIES
(Dollars in millions)

	Years ended December 31, 2008	2007	2006
Proceeds from sales	$ 458	$ 578	$ 474
Gross realized gains	18	18	22
Gross realized losses	(40)	(12)	(13)

Net unrealized gains (losses) are included in Regulatory Liabilities Arising from Removal Obligations on the Consolidated Balance Sheets. We determine the cost of securities in the trusts on the basis of specific identification.

The fair value of securities in an unrealized loss position as of December 31, 2008 was $146 million. The unrealized losses of $47 million were primarily caused by a negative market environment. We do not consider these investments to be other than temporarily impaired as of December 31, 2008.

Customer contribution amounts are determined by the CPUC using estimates of after-tax investment returns, decommissioning costs, and decommissioning cost escalation rates. Changes in investment returns and decommissioning costs may result in a change in future customer contributions.

We discuss the impact of SFAS 143 in Note 1. We provide additional information about SONGS in Notes 10 and 12.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 5. INCOME TAXES

Reconciliation of the U.S. statutory federal income tax rates to the effective income tax rates are as follows:

RECONCILIATION OF FEDERAL INCOME TAX RATES TO EFFECTIVE INCOME TAX RATES

	Years ended December 31,		
	2008	2007	2006
SDG&E			
Statutory federal income tax rate	35 %	35 %	35 %
Depreciation	4	5	5
State income taxes, net of federal income tax benefit	5	5	5
Allowance for equity funds used during construction	(2)	(1)	(1)
Resolution of Internal Revenue Service audits	(3)	(3)	2
Utility repair allowance	(2)	(2)	(2)
Self-developed software expenditures	(3)	(2)	--
Regulatory reserve release	--	(2)	--
Other, net	(2)	(3)	(5)
Effective income tax rate	32 %	32 %	39 %

The components of income tax expense are as follows:

INCOME TAX EXPENSE
(Dollars in millions)

	Years ended December 31,		
	2008	2007	2006
SDG&E			
Current:			
Federal	$ 25	$ 131	$ 209
State	23	44	73
Total	48	175	282
Deferred:			
Federal	107	(24)	(87)
State	8	(14)	(40)
Total	115	(38)	(127)
Deferred investment tax credits	(2)	(2)	(3)
Total income tax expense	$ 161	$ 135	$ 152

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Details of accumulated deferred income taxes at December 31 for SDG&E are shown in the tables below:

ACCUMULATED DEFERRED INCOME TAXES FOR SDG&E
(Dollars in millions)

	SDG&E December 31, 2008	SDG&E December 31, 2007
Deferred tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 625	$ 481
Regulatory balancing accounts	229	82
Loss on reacquired debt	10	11
Property taxes	20	19
Other	--	5
Total deferred tax liabilities	884	598
Deferred tax assets:		
Postretirement benefits	173	78
Investment tax credits	18	20
Compensation-related items	14	14
State income taxes	22	21
Other accruals not yet deductible	37	27
Hedging transaction	--	--
Other	17	7
Total deferred tax assets	281	167
Net deferred income tax liability before valuation allowance	603	431
Valuation allowance	8	8
Net deferred income tax liability	$ 611	$ 439

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

NET DEFERRED INCOME TAX LIABILITY
(Dollars in millions)

	SDG&E 2008	SDG&E 2007
Current (asset) liability	$ (17)	$ (67)
Noncurrent liability	628	506
Total	$ 611	$ 439

Following is a summary of unrecognized tax benefits at December 31, 2008:

SUMMARY OF UNRECOGNIZED TAX BENEFITS
(Dollars in millions)

	SDG&E
Total	$ 18
Of the total, amounts related to tax positions that, if recognized, in future years, would:	
decrease the effective tax rate	$ 17
increase the effective tax rate	$ 17

As of December 31, 2008, SDG&E had $18 million of unrecognized tax benefits. Following is a reconciliation of the unrecognized tax benefits from January 1, 2008 to December 31, 2008:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

RECONCILIATION OF UNRECOGNIZED TAX BENEFITS
(Dollars in millions)

		SDG&E
Balance as of January 1, 2008	$	26
Increase in prior period tax positions		2
Decrease in prior period tax positions		--
Increase in current period tax positions		3
Decrease in current period tax positions		(1)
Settlements with taxing authorities		(12)
Expirations of statutes of limitations		--
Balance as of December 31, 2008	$	18

Effective January 1, 2007, our policy is to recognize accrued interest and penalties on accrued tax balances as components of tax expense. Prior to the adoption of FIN 48, we accrued interest expense and penalties as components of tax expense and interest income as a component of interest income. As of December 31, 2008, $2 million of Interest Expense was accrued.

Amounts accrued for interest expense and penalties associated with income taxes are included in income tax expense on the Statements of Consolidated Income and in various income tax balances on the Consolidated Balance Sheets.

INCOME TAX AUDITS

SDG&E is subject to U.S. federal income tax as well as income tax of state jurisdictions. It remains subject to examination by U.S. federal and state tax jurisdictions only for years after 2001.

NOTE 6. EMPLOYEE BENEFIT PLANS

We account for our employee benefit plans in accordance with:

- FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements 87, 88, 106, and 132(R)*
- FASB Statement No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits - an amendment of FASB Statements No. 87, 88, and 106*
- FASB Statement No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*
- FASB Statement No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*
- FASB Statement No. 87, *Employers' Accounting for Pensions*

These pronouncements require an employer to do the following:

- recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status in the statement of financial position;
- measure a plan's assets and its obligations that determine its funded status as of the end of the 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 comprehensive income and as a separate component of shareholders' equity.

The information presented below covers the employee benefit plans of Sempra Energy and its principal subsidiaries.

Sempra Energy has funded and unfunded noncontributory defined benefit plans, including separate plans for SDG&E and its affiliate, SoCalGas, which together cover substantially all employees and Sempra Energy’s board of directors. The plans provide defined benefits based on years of service and either final average or career salary.

Sempra Energy also has other postretirement benefit plans, including separate plans for SDG&E and SoCalGas, which together cover substantially all employees and Sempra Energy's board of directors. The life insurance plans are both contributory and noncontributory and the health-care plans are contributory. Participants' contributions are 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
- health-care cost trend rates
- mortality rates
- compensation increase rates
- 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. We consider current market conditions, including interest rates, in making these assumptions. We use a December 31 measurement date for all of our plans.

In support of its Supplemental Executive Retirement and Deferred Compensation Plans, Sempra Energy maintains dedicated assets, including investments in life insurance contracts, which totaled $401 million and $440 million at December 31, 2008 and 2007, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Benefit Plan Amendments for 2007 and 2008

Effective July 1, 2008, SDG&E's other postretirement benefit plan was amended to increase the health benefits for certain union participants. This amendment resulted in a $3 million increase at both Sempra Energy and SDG&E in the benefit obligation and unrecognized prior service costs as of December 31, 2007.

Effective January 1, 2008, the pension plans were amended to increase the death benefit for beneficiaries of vested non-union participants. This amendment resulted in a $1 million increase in the benefit obligation and unrecognized prior service costs as of December 31, 2007 at SDG&E.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Benefit Obligations and Assets

The following table provides a reconciliation of the changes in the plans' projected benefit obligations and the fair value of assets during 2008 and 2007, and a statement of the funded status at December 31, 2008 and 2007:

PROJECTED BENEFIT OBLIGATION, FAIR VALUE OF ASSETS AND FUNDED STATUS
(Dollars in millions)

	Pension Benefits		Other Postretirement Benefits	
SDG&E	2008	2007	2008	2007
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Net obligation at January 1	$ 803	$ 842	$ 139	$ 139
Service cost	22	22	5	5
Interest cost	47	47	9	8
Plan amendments	--	1	--	3
Actuarial loss (gain)	(7)	(29)	1	(10)
Transfer of liability to Sempra Energy	(2)	(5)	--	--
Settlements	(1)	--	--	--
Benefit payments	(48)	(75)	(6)	(6)
Net obligation at December 31	814	803	148	139
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at January 1	684	679	67	52
Actual return on plan assets	(191)	56	(16)	3
Employer contributions	38	27	16	15
Settlements	(1)	--	--	--
Transfer of assets to Sempra Energy	(2)	(3)	--	--
Other transfers	--	--	--	3
Benefit payments	(48)	(75)	(6)	(6)
Fair value of plan assets at December 31	480	684	61	67
Funded status at December 31	$ (334)	$ (119)	$ (87)	$ (72)
Net recorded liability at December 31	$ (334)	$ (119)	$ (87)	$ (72)

Net Assets and Liabilities

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. The 10-percent corridor accounting method is used at SDG&E. Under the corridor-accounting method, 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 asset smoothing and 10-percent corridor accounting methods help mitigate volatility of net periodic costs from year to year.

The net asset (liability) is included in the following captions on the Consolidated Balance Sheets at December 31:

	Pension Benefits		Other Postretirement Benefits	
(Dollars in millions)	2008	2007	2008	2007
SDG&E				
Current liabilities	$ (2)	$ (1)	$ --	$ --
Noncurrent liabilities	(332)	(118)	(87)	(72)
Net recorded liability	$ (334)	$ (119)	$ (87)	$ (72)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Amounts recorded in Accumulated Other Comprehensive Income (Loss) as of December 31, 2008 and 2007, net of tax effects and amounts recorded as regulatory assets, are as follows:

AMOUNTS IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	Pension Benefits	
	2008	2007
SDG&E		
Net actuarial loss	$ (13)	$ (16)
Prior service credit	1	1
Total	$ (12)	$ (15)

The accumulated benefit obligations for defined benefit pension plans at December 31, 2008 and 2007 were as follows:

	SDG&E	
(Dollars in millions)	2008	2007
Accumulated benefit obligation	$ 803	$ 795

SDG&E has an unfunded and a funded pension plan. The following table also shows the obligations of funded pension plans with benefit obligations in excess of plan assets as of December 31:

(Dollars in millions)	2008	2007
SDG&E		
Projected benefit obligation	$ 787	$ 774
Accumulated benefit obligation	780	771
Fair value of plan assets	480	684

Net Periodic Benefit Cost, 2006-2008

The following table provides the components of net periodic benefit cost and amounts recognized in other comprehensive income for the years ended December 31:

NET PERIODIC BENEFIT COST AND AMOUNTS RECOGNIZED IN OTHER COMPREHENSIVE INCOME
(Dollars in millions)

SDG&E	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
Net Periodic Benefit Cost						
Service cost	$ 22	$ 22	$ 12	$ 5	$ 5	$ 5
Interest cost	47	47	45	9	8	7
Expected return on assets	(46)	(45)	(41)	(4)	(3)	(2)
Amortization of:						
Prior service cost	1	2	2	3	3	3
Actuarial loss	2	2	6	--	--	--
Regulatory adjustment	14	2	8	2	2	(1)
Settlement charge	2	--	--	--	--	--
Total net periodic benefit cost	42	30	32	15	15	12
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Net gain	(4)	(6)	--	--	--	--
Amortization of actuarial loss	(2)	(2)	--	--	--	--
Total recognized in other comprehensive income	(6)	(8)	--	--	--	--
Total recognized in net periodic benefit cost and other comprehensive income	$ 36	$ 22	$ 32	$ 15	$ 15	$ 12

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The estimated net loss and prior service credit for the pension plans that will be amortized from Accumulated Other Comprehensive Income (Loss) into net periodic benefit cost in 2009 is $2 million at SDG&E.

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 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. We determined that benefits provided to certain participants actuarially will be at least equivalent to Medicare Part D. Thus, we are entitled to a tax-exempt subsidy that reduced our accumulated postretirement benefit obligation under our plans at January 1, 2008 and reduced the net periodic cost for 2008 by the following amounts:

(Dollars in millions)	SDG&E
Accumulated postretirement benefit obligation reduction	$ 20
Net periodic benefit cost reduction	2

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

We develop 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. We then calculate a single equivalent discount rate that 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.

The significant assumptions affecting benefit obligation and net periodic benefit cost are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AS OF DECEMBER 31:				
Discount rate	6.00%	6.10%	6.10%	6.20%
Rate of compensation increase	4.50%	4.50%	4.00%	4.00%
WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COSTS FOR YEARS ENDED DECEMBER 31:				
SDG&E				
Discount rate	6.10%	5.75%	6.20%	5.85%
Expected return on plan assets	7.00%	7.00%	5.89%	5.50%
Rate of compensation increase	(3)	(3)	N/A	N/A

(3) 4.50% for the non-qualified pension plan. An age-based formula is used for the qualified pension plan.

Health-Care Cost Trend Rates

Assumed health-care cost trend rates have a significant effect on the amounts that we report for the health-care plan costs. Following are the health-care cost trend rates applicable to our postretirement benefit plans:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	2008	2007
ASSUMED HEALTH-CARE COST TREND RATES AT DECEMBER 31:		
Health-care cost trend rate*	9.44 %	9.48 %
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	2014 and 2016**	2014 and 2016**

* *This is the weighted average of the increases for all of our health plans. The rate for these plans ranged from 8.50% to 10.00% in 2008 and 2007.*

** *The ultimate trend rate is reached in 2014 for HMOs and 2016 for Anthem Blue Cross Plans.*

A one-percent change in assumed health-care cost trend rates would have the following effects:

	SDG&E	
(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 Trust Investment Strategies

Investment Strategy for SDG&E's Postretirement Health Plans

SDG&E'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. SDG&E's investment strategy is to maintain a diversified portfolio of equities and tax-exempt California municipal bonds.

The asset allocation for SDG&E's postretirement health plans at December 31, 2008 and 2007 and the target allocation for 2009 by asset categories are as follows:

	Target Allocation	Percentage of Plan Assets at December 31,	
Asset Category	2009	2008	2007
U.S. Equity	25 %	28 %	25 %
Foreign Equity	5	4	5
Fixed Income	70	68	70
Total	100 %	100 %	100 %

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Future Payments

We expect to contribute the following amounts to our pension and other postretirement benefit plans in 2009:

(Dollars in millions)	SDG&E
Pension plans	$ 60
Other postretirement benefit plans	17

The following two tables show the total benefits we expect to pay for the next 10 years to current employees and retirees from the plans or from company assets.

	SDG&E	
(Dollars in millions)	Pension Benefits	Other Postretirement Benefits
2009	$ 63	$ 7
2010	77	8
2011	86	9
2012	81	10
2013	82	12
2014-2018	397	72

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

(Dollars in millions)	SDG&E
2009	$ --
2010	--
2011	--
2012	1
2013	1
2014-2018	5

SAVINGS PLANS

SDG&E offers trusteed savings plans to all employees. Participation in the plans 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 when they begin employment. After one year of each employee's completed service, Sempra Energy makes matching contributions. Employer contribution amounts and methodology vary by plan, but generally the 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 the employee may transfer the contribution to 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), which the employee selects. In Sempra Energy plans, employee contributions may also be invested in guaranteed investment contracts.

Contributions to the savings plans were as follows:

(Dollars in millions)	2008	2007	2006
SDG&E	13	12	11

The market value of Sempra Energy common stock held by the savings plans was $700 million and $997 million at December 31, 2008 and 2007, respectively.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 7. SHARE-BASED COMPENSATION

SEMPRA ENERGY EQUITY COMPENSATION PLANS

Sempra Energy has share-based compensation plans intended to align employee and shareholder objectives related to the long-term growth of Sempra Energy. The plans permit a wide variety of share-based awards, including:

- non-qualified stock options
- incentive stock options
- restricted stock
- restricted stock units
- stock appreciation rights
- performance awards
- stock payments
- dividend equivalents

Eligible SDG&E employees participate in Sempra Energy's share-based compensation plans as a component of their compensation package.

At December 31, 2008, Sempra Energy had 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, become exercisable over a four-year period, and expire 10 years from the date of grant. Vesting and/or the ability to exercise may be accelerated upon a change in control, in accordance with severance pay agreements or upon eligibility for retirement. Options are subject to forfeiture or earlier expiration when an employee terminates employment.
- *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. Vesting is subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control, in accordance with severance pay agreements or upon eligibility for retirement. Holders of restricted stock have full voting rights. They also have full dividend rights; however, dividends paid on restricted stock held by officers are reinvested to purchase additional shares that become subject to the same vesting conditions as the restricted stock to which the dividends relate.
- *Restricted Stock Units:* Restricted stock units vest at the end of a four-year period based on Sempra Energy’s total return to shareholders relative to that of market indices. If Sempra Energy’s total return to shareholders exceeds the target levels designated in the 2008 Long Term Incentive Plan, up to an additional 50 percent of the number of granted restricted stock units may be issued. If Sempra Energy's total return to shareholders is below the target levels, shares are subject to partial vesting on a pro rata basis. Vesting is subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control, in accordance with severance pay agreements or upon eligibility for retirement. Dividend equivalents on restricted stock units are reinvested to purchase additional shares that become subject to the same vesting conditions as the restricted stock units to which the dividends relate.

SHARE-BASED AWARDS AND COMPENSATION EXPENSE

Sempra Energy accounts for share-based awards in accordance with SFAS 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)). SFAS 123 requires that we measure and recognize compensation expense for all share-based payment awards made to our employees and directors based on estimated fair values. We adopted the provisions of SFAS 123(R) on January 1, 2006, using the modified prospective transition method. In accordance with this transition method, Sempra Energy’s consolidated financial statements for prior periods were not 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 fair value estimated in accordance with the original provisions of SFAS 123, *Accounting for Stock-Based Compensation* (SFAS 123).

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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). We recognize compensation costs net of an estimated forfeiture rate (based on historical experience) and recognize the compensation costs for non-qualified stock options and restricted shares on a straight-line basis over the requisite service period of the award, which is generally four years. However, in the year that an employee becomes eligible for retirement, the remaining expense related to the employee's awards is recognized immediately. We account for these awards as equity awards in accordance with SFAS 123(R).

The tax benefits resulting from tax deductions in excess of the tax benefit related to compensation cost recognized for stock option exercises are classified as financing cash flows.

SDG&E records 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. Expenses and capitalized compensation cost recorded by SDG&E were as follows:

SHARE-BASED COMPENSATION – SDG&E
(Dollars in millions)

	Years ended December 31,		
	2008	2007	2006
SDG&E			
Compensation expense	$ 8	$ 6	$ 7
Capitalized compensation cost	3	2	2

SEMPRA ENERGY RESTRICTED STOCK AWARDS AND UNITS

We use a Monte-Carlo simulation model to estimate the fair value of the restricted stock awards and units. Our determination of fair value is affected by the volatility of the stock price and the dividend yields for Sempra Energy and its peer group companies. The valuation also is affected by the risk-free rates of return, and a number of other variables. Below are key assumptions for Sempra Energy:

	2008	2007	2006
Risk-free rate of return	3.1 %	4.6 %	4.3 %
Annual dividend yield	2.3	2.2	2.6
Stock price volatility	18	19	24

Restricted Stock Awards

A summary of Sempra Energy's restricted stock awards as of December 31, 2008 and the activity during the year is presented below.

RESTRICTED STOCK AWARDS

	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2007	2,758,797	$ 35.79
Granted	4,002	$ 43.17
Vested	(1,005,311)	$ 38.77
Forfeited	(46,500)	$ 34.81
Nonvested at December 31, 2008	1,710,988	$ 34.06

The $11 million of total compensation cost related to nonvested restricted stock awards not yet recognized as of December 31, 2008 is expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested in the last three years was:

- $39 million in 2008
- $37 million in 2007
- $68 million in 2006

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Restricted Stock Units

A summary of Sempra Energy's restricted stock units as of December 31, 2008 and the activity during the year is presented below.

RESTRICTED STOCK UNITS

	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2007	5,400	$ 62.26
Granted	643,250	$ 52.80
Vested	--	--
Forfeited	(22,300)	$ 52.87
Nonvested at December 31, 2008*	626,350	$ 52.70

* *Additional units may be granted if Sempra Energy exceeds the target shareholder return requirements designated in the 2008 Long Term Incentive Plan.*

The $13 million of total compensation cost related to nonvested restricted stock units not yet recognized as of December 31, 2008 is expected to be recognized over a weighted-average period of 3.0 years.

NOTE 8. FINANCIAL INSTRUMENTS

We periodically use interest-rate swap agreements and commodity derivative instruments to moderate our exposure to commodity price changes and interest-rate changes and to lower our overall cost of borrowing.

CASH FLOW HEDGES

Cash flow interest-rate swap hedges at December 31, 2008 and 2007 were:

	December 31, 2008		December 31, 2007	
(Dollars in millions)	Notional Debt	Maturities	Notional Debt	Maturities
SDG&E	176	2009	251	2009

The following table provides the balances in Accumulated Other Comprehensive Income (Loss), net of income tax, related to all cash flow hedges:

	December 31,	
(Dollars in millions)	2008	2007
SDG&E	(1)	(1)

SDG&E expects that losses of $1 million, which are net of income tax benefit, that are currently recorded in Accumulated Other Comprehensive Income (Loss) related to these cash flow hedges will be reclassified into earnings during the next twelve months as the hedged items affect earnings.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

HEDGE INEFFECTIVENESS

Following is a summary of the hedge ineffectiveness gains (losses) for SDG&E:

	Years ended December 31,		
(Dollars in millions)	2008	2007	2006
Interest-rate hedges*:			
Cash flow hedges held by SDG&E**	(1)	(3)	(1)

* *For interest-rate swap instruments, all companies record ineffectiveness gains (losses) in Other Income (Expense), Net on the Statements of Consolidated Income.*

** *The 2008 and 2007 losses include $(1) million and a negligible amount, respectively, associated with Otay Mesa VIE.*

At SDG&E, company policy and regulatory requirements impose limits on the use of derivative instruments. These instruments enable the companies to estimate with greater certainty the effective prices to be received by the companies and the prices to be charged to their customers. SDG&E records realized gains or losses on derivative instruments associated with transactions for electric energy contracts in Cost of Electric Fuel and Purchased Power on the Statements of Consolidated Income. SDG&E also records realized gains and losses on derivative instruments associated with transactions for natural gas contracts in Cost of Natural Gas on the Statements of Consolidated Income. On the Consolidated Balance Sheets, SDG&E records regulatory assets and liabilities related 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 our financial instruments (cash, temporary investments, accounts and notes receivable, dividends and accounts payable, short-term debt 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:

	2008		2007	
(Dollars in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
SDG&E				
Total long-term debt[1]	$ 2,146	$ 2,073	$ 1,960	$ 1,975
Preferred stock	79	71	93	90

1 *Before reductions for unamortized discount of $2 million at both December 31, 2008 and 2007.*

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

Adoption of FSP FIN 39-1

We adopted FSP FIN 39-1 effective January 1, 2008, which required retroactive application. The Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when management believes a legal right of setoff exists.

The following table provides the amount of fair value of cash collateral receivables that were offset against net derivative positions in the Balance Sheet as of December 31, 2008 and December 31, 2007 at SDG&E:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

(Dollars in millions)	December 31, 2008	December 31, 2007
SDG&E	$ 52	$ 9

The following table provides the amount of fair value of cash collateral that was not offset in the Balance Sheet as of December 31, 2008 and December 31, 2007 at SDG&E:

(Dollars in millions)	December 31, 2008	December 31, 2007
SDG&E	$ 21	$ 6

Fair Value Hierarchy

We discuss the valuation techniques we use to measure fair value and the definition of the three levels of the fair value hierarchy, as defined in SFAS 157, in Note 1 under "Fair Value Measurements" and in Note 2 under "FSP FAS 157-3."

The three tables below, by level within the fair value hierarchy, set forth our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008 and 2007. As required by SFAS 157, we classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities, and their placement within the fair value hierarchy levels.

The fair value of commodity derivative assets and liabilities is determined in accordance with our netting policy, as discussed above under "Adoption of FSP FIN 39-1."

Determining the fair values, shown in the tables below, incorporates various factors required under SFAS 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of the risk of our nonperformance on our liabilities.

Our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008 and 2007 in the tables below include the following:

- Nuclear decommissioning trusts reflect the assets of SDG&E's nuclear decommissioning trusts, excluding cash balances, as we discuss in Note 4. The trust assets are valued by a third party trustee. The trustee obtains prices from pricing services that are derived from observable data. The trustee monitors the prices supplied by pricing services by validating pricing with other sources of data.
- Investments include marketable securities and are primarily priced based on observable interest rates for similar instruments actively trading in the marketplace.
- Commodity and other derivative positions, which include other interest-rate management instruments, are entered into primarily as a means to manage price exposures. We use market participant assumptions to price these derivatives. Market participant assumptions include those about risk, and the risk inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable.

In the third quarter of 2007, the California Independent System Operator (ISO) began the process of allocating congestion revenue rights (CRRs) to load serving entities, including SDG&E. These instruments are included with commodity derivatives and are recorded at fair value based on annual auction prices published by the California ISO. Prior to the ISO auction conducted in November 2008, the CRRs were priced based on discounted cash flows. They are classified as Level 3 and reflected in the tables below. Changes in the fair value of CRRs are deferred and recorded in regulatory accounts to the extent they are recoverable through rates.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

RECURRING FAIR VALUE MEASURES – SDG&E
(Dollars in millions)

	At fair value as of December 31									
		Level 1		Level 2		Level 3		Netting and Collateral		Total
2008:										
Assets:										
Commodity derivatives	$	21	$	--	$	27	$	--	$	48
Nuclear decommissioning trusts*		421		148		--		--		569
Short-term investments		--		24		--		--		24
Total	$	442	$	172	$	27	$	--	$	641
Liabilities:										
Commodity derivatives	$	52	$	24	$	--	$	(52)	$	24
Other derivatives		--		88		--		--		88
Total	$	52	$	112	$	--	$	(52)	$	112
2007**:										
Assets:										
Commodity derivatives	$	9	$	3	$	7	$	--	$	19
Nuclear decommissioning trusts*		551		175		--		--		726
Total	$	560	$	178	$	7	$	--	$	745
Liabilities:										
Trading derivatives	$	9	$	8	$	--	$	(9)	$	8
Other derivatives		--		20		--		--		20
Total	$	9	$	28	$	--	$	(9)	$	28

* *Excludes cash balances.*
** *Amounts have been reclassified to reflect the retrospective application of FSP FIN 39-1.*

Level 3 Information

The following table set forth reconciliations of changes in the fair value of net trading and other derivatives classified as Level 3 in the fair value hierarchy:

	SDG&E			
	December 31,			
(Dollars in millions)		2008		2007
Balance as of January 1	$	7	$	--
Realized and unrealized gains (losses)		3		--
Allocated transmission instruments		17		7
Balance as of December 31	$	27	$	7
Change in unrealized gains relating to instruments still held as of December 31	$	27	$	7

Transfers in and/or out of Level 3 represent existing assets or liabilities that were either:

- previously categorized as a higher level for which the inputs to the model became unobservable; or
- assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

There were no transfers in or out of Level 3 during the periods presented.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 9. PREFERRED STOCK

The table below shows the details of preferred stock for SDG&E.

	Call/ Redemption Price	December 31, 2008	2007
		(in millions)	
Subject to mandatory redemption:			
SDG&E:			
Without par value: $1.7625 Series, 550,000 shares outstanding at December 31, 2007*	$ 25.00	$ --	$ 14
Sempra Energy - total preferred stock of subsidiary subject to mandatory redemption		$ --	$ 14
Not subject to mandatory redemption:			
SDG&E:			
$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 preferred stock of SDG&E, not subject to mandatory redemption		79	79

* *At December 31, 2007, $14 million was included in Other Current Liabilities. This series was redeemed on January 15, 2008.*

The following are the attributes of SDG&E's preferred stock:

- All outstanding series are callable.
- The $1.7625 Series had a sinking fund requirement to redeem 50,000 shares at $25 per share in 2007 and all remaining shares in 2008. On January 15, 2007, SDG&E redeemed 100,000 shares, and on January 15, 2008, SDG&E redeemed the remaining 550,000 shares.
- 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.
- All outstanding series of SDG&E's preferred stock have cumulative preferences as to dividends.
- 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).

SDG&E is currently authorized 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 SDG&E was otherwise authorized to issue, and when issued would rank junior to the Cumulative Preferred Stock and Preference Stock (Cumulative). The stock’s rights, preferences and privileges would be established by the board at the time of issuance.

NOTE 10. ELECTRIC INDUSTRY REGULATION

BACKGROUND

California's legislative response to the 2000 - 2001 energy crisis resulted in the California Department of Water Resources (DWR) purchasing a substantial portion of power for California's electricity users. In 2001, the DWR entered into long-term contracts with suppliers, including Sempra Generation, to provide power for the utility procurement customers of each of the California investor-owned utilities (IOUs), including SDG&E. The California Public Utilities Commission (CPUC) allocates the power and its administrative responsibility, including collection of power contract costs from utility customers, among the IOUs. Effective in 2003, the IOUs resumed responsibility for electric commodity procurement above their allocated share of the DWR's long-term contracts.

POWER PROCUREMENT AND RESOURCE PLANNING

Effective in 2003, the CPUC:

- directed the IOUs, including SDG&E, to resume electric commodity procurement to cover their net short energy requirements, which are the total customer energy requirements minus supply from resources owned, operated or contracted;
- implemented legislation regarding procurement and renewable energy portfolio standards; and
- established a process for review and approval of the utilities' long-term resource and procurement plans.

This process is intended to identify anticipated needs for generation and transmission resources in order to support transmission grid reliability and to better serve customers.

Sunrise Powerlink Electric Transmission Line

In December 2008, the CPUC issued a final decision authorizing SDG&E to construct a 500-kilovolt (kV) electric transmission line between the Imperial Valley and the San Diego region (Sunrise Powerlink). This line is designed to provide 1,000 MW of increased import capability into the San Diego area. The decision allows SDG&E to construct the Sunrise Powerlink along a route that would generally run south of the Anza-Borrego Desert State Park. The decision also approves the environmental impact review jointly conducted by the CPUC and the Bureau of Land Management (BLM) and establishes a total project cost cap of $1.883 billion, including approximately $190 million for environmental mitigation costs. In January 2009, the BLM issued its decision approving the project, route and environmental review.

Sunrise Powerlink costs will be recovered in SDG&E's Electric Transmission Formula Rate (described below), where SDG&E must demonstrate to the FERC that such costs were prudently incurred.

The CPUC decision requires SDG&E to adhere to certain commitments it made during the application process, as follows:

- not to contract, for any length of term, with conventional coal generators to deliver power via the Sunrise Powerlink;
- if any currently approved renewable energy contract that is deliverable via the Sunrise Powerlink fails, to replace it with a viable contract with a renewable generator located in the Imperial Valley; and
- voluntarily raise SDG&E's Renewables Portfolio Standard (RPS) goal to 33 percent by 2020.

The decision is subject to rehearing before the CPUC and appeal to the California courts of appeal, or to the California Supreme Court. Rehearing requests were required to be filed with the CPUC on or before January 23, 2009, and parties wishing to appeal must first seek rehearing with the CPUC. The Utility Consumers Action Network and the Center for Biological Diversity/Sierra Club (CBD) timely applied for rehearing. In addition, on January 21, 2009, CBD filed a petition for writ of review of the CPUC decision with the California Supreme Court. The Supreme Court denied that petition on February 18, 2009.

The Sunrise Powerlink route crosses federal land and requires discretionary approvals from the BLM and the United States Forest Service (USFS). The BLM issued a decision approving its segment of the route on January 20, 2009. SDG&E expects the USFS to issue a decision approving its segment of the route in the second quarter of 2009. Both the BLM and the USFS approvals may be the subject of administrative and judicial appeals.

Before construction can begin, additional discretionary agency permits must be obtained, and those permits may be subject to independent legal review. SDG&E expects the Sunrise Powerlink to be in commercial operation in 2012.

Renewable Energy

Pursuant to Senate Bill 107, enacted in September 2006, the California Public Utilities Code requires certain California electric retail sellers, including SDG&E, to deliver 20 percent of their 2010 retail demand from renewable energy sources. The rules governing this requirement, administered by both the CPUC and the California Energy Commission, are generally known as the Renewables Portfolio Standard (RPS) Program.

In February 2008, the CPUC issued a decision defining flexible compliance mechanisms that can be used to meet the RPS Program goals in 2010 and beyond, including clarifying rules within which insufficient transmission is a permissible reason for failing to satisfy the RPS Program goals. While SDG&E believes it will be able to comply with the RPS Program requirements based on its contracting activity and application of the flexible compliance mechanisms, it is possible that SDG&E could be penalized, though we cannot know the amount that would be imposed.

SDG&E continues to aggressively secure renewable energy supplies to achieve the RPS Program goals. A substantial number of these supply contracts, however, are contingent upon many factors, including:

- access to electric transmission infrastructure (including SDG&E's Sunrise Powerlink transmission line);
- timely regulatory approval of contracted renewable energy projects;
- the renewable energy project developers' ability to obtain project financing and permitting; and
- successful development and implementation of the renewable energy technologies.

While CPUC approval was received for the Sunrise Powerlink project in December 2008, due to the extended regulatory review period, SDG&E does not expect the Sunrise Powerlink transmission line to be in operation until 2012, too late to provide transmission capability to meet the RPS Program requirements for 2010 and 2011. Consequently, it is unlikely that SDG&E will be able to meet the RPS Program delivered-energy goal for those years. Without the application of the flexible compliance mechanisms, SDG&E's failure to attain the 20-percent goal in 2010, or any subsequent years' goals, could subject it to CPUC-imposed penalties of 5 cents per kilowatt hour of renewable energy under-delivery up to a maximum penalty of $25 million per year.

Miramar II Peaking Plant

In January 2009, the CPUC issued a final decision approving SDG&E's application to construct a natural gas-fired peaking plant in San Diego (Miramar II), next to an existing SDG&E peaking plant. Miramar II is currently estimated to cost $57 million and will have a capacity of 46.5 MW. SDG&E will own and operate the plant. SDG&E expects the plant to be in operation by mid-2009.

Solar Photovoltaic Program

In July 2008, SDG&E filed an application with the CPUC proposing to install solar photovoltaic panels in the San Diego area. These panels could potentially generate approximately 50 MW of direct current power (approximately equivalent to 35 MW of power to the electric grid). We estimate the cost of the program to be $250 million. A CPUC decision is expected in the third quarter of 2009. If approved, we expect the program to be completed in 2013.

Long-Term Procurement Plan

In December 2007, SDG&E exercised its option to acquire the El Dorado power plant in 2011 at Sempra Generation's net book value. We estimate that the net book value at the date of acquisition will be approximately $189 million.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

San Onofre Nuclear Generating Station (SONGS)

SONGS is jointly owned by Southern California Edison (Edison) (78.21%), SDG&E (20%) and the city of Riverside (1.79%). In September 2008, as part of Edison's 2009 General Rate Case, SDG&E requested a $116.2 million base revenue requirement for 2009 (a $10.2 million increase) to recover costs for its 20-percent ownership in SONGS. SDG&E also requested $13.2 million for its share of SONGS refueling outage expenses (per refueling outage) in 2009, a decrease of $2.7 million. The CPUC issued draft and alternate decisions in November 2008, and SDG&E expects the final CPUC decision in the first quarter of 2009. Until a final decision is approved, SDG&E has received approval from the CPUC to track the change in SONGS-related revenue requirement from January 1, 2009 through the effective date of the final decision.

Edison is in the process of replacing the steam generators at SONGS. Project completion is expected in 2010 and 2011 for Units 2 and 3, respectively. Total estimated capital expenditure for the project, in 2004 dollars, is $671 million, excluding AFUDC. SDG&E's current expected share is $169 million, of which $51 million has been incurred through December 31, 2008, and there are $60 million of firm commitments at December 31, 2008. In 2006, the CPUC approved SDG&E's participation in the replacement project as well as providing SDG&E with full recovery of current operating and maintenance costs via balancing account treatment effective January 1, 2007.

Spent Nuclear Fuel

SONGS owners are responsible for interim storage of spent nuclear fuel generated at SONGS until the DOE accepts it for final disposal. Spent nuclear fuel has been stored in the SONGS Units 1, 2 and 3 spent fuel pools and in the independent spent fuel storage installation (ISFSI). Movement of all Unit 1 spent fuel to the ISFSI was completed in 2005.

- Spent fuel for Unit 2 is being stored in both the Unit 2 spent fuel pool and the ISFSI.
- Spent fuel for Unit 3 is being stored in both the Unit 3 spent fuel pool and the ISFSI.

Construction of a second ISFSI pad to be completed in 2009 will provide sufficient storage capacity to allow for the continued operation of SONGS through 2022.

Electric Transmission Formula Rate

Effective July 1, 2007, SDG&E recovers its annual transmission capital investment at a return on equity (ROE) of 11.35 percent, an increase from the previous authorized ROE of 11.25 percent. In May 2007, the FERC approved a formula rate mechanism that allows SDG&E to recover the cost of owning and operating its transmission system through annual informational filings with revised rates effective September 1 of each year. In August 2008, SDG&E made such a filing with the FERC, increasing SDG&E's transmission revenue requirement by $85 million, or 40%, effective September 1, 2008, for a twelve-month period. SDG&E’s formula rate mechanism remains in effect through August 2013.

NOTE 11. OTHER REGULATORY MATTERS

GENERAL RATE CASE (GRC)

The CPUC uses a general rate case proceeding to determine SDG&E’s reasonable level of costs and to set rates sufficient to allow SDG&E to recover their costs and realize an acceptable rate of return on their investment.

In July 2008, the CPUC issued its final decision in SDG&E's 2008 General Rate Case (2008 GRC). The decision adopted the test-year 2008 revenue requirements, effective retroactive to January 1, 2008. It also adopted the post-test year revenue requirements that were included in settlement agreements filed with the CPUC. These settlement agreements were with various groups representing the interests of ratepayers and other constituents.

The CPUC decision:

- increased the 2008 annual revenue requirement as compared to 2007 by $138 million for SDG&E;

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report 2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

- provides average annual increases of approximately $43 million (3%) for SDG&E, in each of the post-test years' (2009 through 2011) revenue requirements;
- established a GRC period of four years (2008-2011); and
- excludes any earnings cap or earnings sharing during the GRC period.

SDG&E will file its next GRC application in December 2010 for test year 2012.

UTILITY INCENTIVE MECHANISMS

The CPUC applies performance-based measures and incentive mechanisms to all California utilities. Under such measures or mechanisms, SDG&E has income potential above authorized base margins if it achieves or exceeds specific performance and operating goals, rather than relying solely on expanding utility plant to increase earnings. Generally, for performance-based awards, if performance is above or below specific benchmarks, SDG&E is eligible for financial awards or subject to financial penalties. There are three general areas that operate under an incentive structure:

- employee safety
- energy efficiency programs
- natural gas unbundled storage and system operator hub services

Incentive awards are included in our earnings when we receive the CPUC's approval of the award, if applicable. All award amounts discussed below are on a pretax basis.

Employee Safety

The CPUC determines operational incentives and the associated benchmarks as a component of a general rate case or cost of service decision. The operational performance incentives in effect for fiscal years 2008 through 2011 were established as part of the CPUC's final decision in the 2008 GRC. This decision adopted modified performance measures for customer satisfaction, employee safety, and electric reliability for SDG&E. SDG&E reviewed these modified measures and filed its response in September 2008, accepting the safety performance measure but rejecting the electric reliability and customer satisfaction measures, as allowed by the GRC decision. As a result, effective in 2008, SDG&E is no longer eligible for awards or subject to penalties for electric reliability and customer satisfaction.

During the second quarter of 2008, SDG&E received CPUC approval for its 2007 Operational Performance incentive awards of $10 million. SDG&E plans to submit its employee safety results and incentive award claims in May 2009 for performance in 2008.

Energy Efficiency

Energy efficiency awards are determined under an incentive mechanism established by the CPUC that applies to SDG&E’s performance over a three-year (2006 – 2008) energy efficiency program period. In December 2008, the CPUC approved energy efficiency awards of $10.8 million for SDG&E for 2006 and 2007 energy efficiency results. The awards were based on initial reports of energy efficiency results submitted by SDG&E and are net of a holdback of 65%. None, some or all of the holdback may be awarded to SDG&E after the CPUC staff completes its final verification of the energy efficiency results.

In accordance with the mechanism, SDG&E plans on filing in the first quarter of 2009 for its energy efficiency awards for 2008 results.

Natural Gas Procurement

Beginning April 1, 2008, the SDG&E and SoCalGas core natural gas supply portfolios were combined, and SoCalGas now procures natural gas for SDG&E's core natural gas customers' requirements. All SDG&E assets associated with its core natural gas supply portfolio were transferred or assigned to SoCalGas. Accordingly, SDG&E’s incentive mechanism for natural gas procurement awards or penalties ended as of the effective date of the combination of the core natural gas supply portfolios, and SoCalGas' gas cost incentive mechanism (GCIM) is applied on the combined portfolio basis going forward.

In November 2008, SDG&E received approval of a $2.2 million natural gas procurement incentive award for the final eight-month

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

period ended March 31, 2008.

COST OF CAPITAL

The cost of capital proceeding determines SDG&E’s authorized capital structure and the authorized rate of return that SDG&E may earn on its electric and natural gas distribution and electric generation assets.

In May 2007, SDG&E filed an application with the CPUC seeking to update its cost of capital, authorized ROE, and debt/equity ratios. In December 2007, the CPUC issued a final decision increasing SDG&E’s authorized ROE from 10.7 percent to 11.1 percent effective January 1, 2008, and maintaining SDG&E's current capital structure of:

- 49.00 percent common equity
- 5.75 percent preferred equity
- 45.25 percent long-term debt

As a result, SDG&E’s authorized return on rate base (ROR) was 8.40 percent effective January 1, 2008.

In May 2008, the CPUC issued a decision establishing a uniform, multi-year cost of capital mechanism for SDG&E that will replace its existing cost of capital mechanism. The new mechanism requires a full cost of capital application every third year, with the first full application to be filed in April 2010 for test year 2011. If there were significant changes in the bond market between test years, ROE would automatically be adjusted. In any year where the difference between the current 12-month October-September average Moody's utility bond rates and the established benchmark (currently 6.02%) exceeds a 100-basis point trigger, an automatic adjustment to SDG&E's ROE would be made through an October 15 advice letter to become effective on January 1 of the following year. No change in ROE has been triggered for calendar year 2009. There is no provision for capital structure adjustment outside of the test year, but an adjustment may be permitted if credit ratings change in mid-cycle. The decision also allows an adjustment outside of the mechanism process if an extraordinary or catastrophic event occurs that has a material impact.

2008 BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

The purpose of the BCAP is to adopt a new forecast of natural gas demand to allocate costs and set rates to enable SDG&E to recover its natural gas distribution costs.

In August 2006, SDG&E, SoCalGas and Edison jointly filed an application with the CPUC seeking its approval of a series of revisions to the natural gas operations and service offerings of the Sempra Utilities. The CPUC issued a final decision in December 2007 approving some, but not all, of the proposals and deferring a number of issues to the Sempra Utilities’ BCAP where they could be addressed more fully. The CPUC issued its final decision approving the uncontested settlement in December 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 Order Instituting Rulemaking (OIR). In September 2006, a final decision in Phase II of this proceeding was issued. This decision reaffirmed the adequacy of the capacity of SDG&E’s system to meet then-current and forecasted demand. Among other things, this decision established revised natural gas quality standards that apply to all natural gas supplies entering the SDG&E system, including new supplies of regasified liquefied natural gas. The South Coast Air Quality Management District and the City of San Diego (jointly with Ratepayers for Affordable Clean Energy) filed petitions for review in the California Court of Appeal and the California Supreme Court challenging the CPUC's September 2006 decision. In November 2007, the Court of Appeal determined that the California Supreme Court had exclusive jurisdiction over the petitions for review. In July 2008, the California Supreme Court denied the petitions for review, thereby affirming the CPUC's decision in all respects.

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report 2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

ADVANCED METERING INFRASTRUCTURE

In April 2007, the CPUC approved SDG&E's request to install advanced meters with integrated two-way communications functionality, providing a home area network for all customers, including remote disconnect for the majority of residential customers. SDG&E estimates expenditures for this project of $572 million (including approximately $500 million in capital investment). This project involves replacing 1.4 million electric meters and 900,000 natural gas meters throughout SDG&E's service territory. Based on the evaluation of an initial installation of 4,500 meters, SDG&E plans to begin full-scale deployment in the second quarter of 2009, with completion by the end of 2011.

GREENHOUSE GAS REGULATION

Legislation was enacted in 2006, including California Assembly Bill 32 (AB 32) and California Senate Bill 1368, mandating reductions in greenhouse gas emissions. The California Air Resources Board (CARB) is the lead agency in developing a plan to meet these requirements and is in the process of developing rules and market mechanisms that will be implemented on January 1, 2012. The CPUC and California Energy Commission are also in the process of making recommendations to the CARB regarding the rules that should apply for the electricity and natural gas sectors. The CARB's formal AB 32 Scoping Plan was adopted in December 2008.

These legislative mandates could affect costs and growth at SDG&E. Any cost impact at SDG&E is expected to be recoverable through rates.

NOTE 12. COMMITMENTS AND CONTINGENCIES

LEGAL PROCEEDINGS

We record reserves for legal proceedings in accordance with SFAS 5, *Accounting for Contingencies*. At December 31, 2008, SDG&E had reserves for unresolved legal proceedings of $31 million. The uncertainties that exist in legal proceedings make it difficult to estimate with reasonable certainty the costs and effects of resolving these matters. Accordingly, actual costs incurred may differ materially from insured or reserved amounts and could materially adversely affect our business, cash flows, results of operations, and financial condition.

SDG&E 2007 Wildfire Litigation

In October 2007, San Diego County experienced catastrophic wildfires. In July 2008, the California Department of Forestry and Fire Protection (Cal Fire) issued investigation reports stating that two fires (the Witch and Rice fires) were SDG&E "power line caused" and that a third fire (the Guejito fire) occurred when a wire securing a Cox Communications' fiber optic cable came into contact with an SDG&E power line "causing an arc and starting the fire." Cal Fire states that the Rice fire burned approximately 9,500 acres and damaged 206 homes and two commercial properties. The reports indicate that the Witch and Guejito fires merged and eventually burned approximately 198,000 acres, resulted in two fatalities, injured approximately 40 firefighters and destroyed approximately 1,141 homes. Cal Fire is still investigating the perimeters of these two fires to determine the damages associated with each fire. In September 2008, the Consumer Protection and Safety Division of the California Public Utilities Commission issued a staff investigative report reaching substantially the same conclusions as the Cal Fire reports. However, the staff report also opines that the power lines involved in the Witch and Rice fires and the lashing wire involved in the Guejito fire were not properly designed, constructed and maintained as required by commission rules. In November 2008, the Commission initiated an investigation to determine whether SDG&E and Cox Communications violated any rules or regulations in connection with the fires.

Approximately 100 lawsuits, some of which seek class action certification, have been filed against SDG&E and Sempra Energy in San Diego County Superior Court seeking to recover damages in unspecified amounts, including punitive damages and other costs associated with the three fires. Plaintiffs include owners and insurers of properties that were damaged or destroyed and public entities seeking recovery of firefighting costs. They assert various bases for recovery, including inverse condemnation based upon a California

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Court of Appeal decision finding that another California investor-owned utility was subject to strict liability, without regard to foreseeability or negligence, for damages resulting from a wildfire ignited by power lines. SDG&E has filed cross-complaints against Cox Communications seeking indemnification for any liability that SDG&E may incur that relates to the Guejito fire.

By January 2009, insurers representing 92 percent of the total California homeowner insurance market have paid out approximately $1.4 billion on more than 18,000 claims relating to the three fires. These include claims for approximately 900 of the 1,300 houses, mobile homes, and apartment units identified in public records as having been destroyed by the three fires. The litigation includes additional claims for uninsured and underinsured structures, firefighting costs, business interruption, evacuation expenses, agricultural damage, and personal injuries. The wildfire litigation, including any appeals, could take a number of years to be resolved in light of the complexity of the matters and the large number of parties and claims involved. If SDG&E’s ultimate liability were to exceed its $1.1 billion of liability insurance coverage, SDG&E would request authorization from the FERC and CPUC to recover the excess amounts in utility rates. The company is unable to predict the degree of success SDG&E may have in pursuing such requests or the timing of any recovery.

Other Litigation

We are also defendants in ordinary routine litigation incidental to our businesses, including personal injury, product liability, property damage and other claims. California juries have demonstrated an increasing willingness to grant large awards, including punitive damages, in these cases.

Resolved Matters

We have accrued liabilities for resolved matters of $32 million at SDG&E. These amounts are for settlements related to certain litigation arising out of the 2000 – 2001 California energy crisis.

The following is a description of specific litigation settlements.

Continental Forge Settlement

The Continental Forge class-action and individual antitrust and unfair competition lawsuits in California and Nevada alleged that the Sempra Utilities unlawfully sought to control natural gas and electricity markets. The detailed terms of these settlements were reported previously, and are summarized as follows:

- In January 2006, in order to settle the California and Nevada litigation, we agreed to make cash payments in installments totaling $377 million. Of this amount, $347 million relates to the California Continental Forge and California class action price reporting litigation, and $30 million relates to the Nevada Continental Forge litigation. In March 2007, the Sempra Utilities entered into a separate settlement agreement with the City of Los Angeles resolving all of its claims in the Continental Forge litigation in return for payment of $8.5 million.
- Additional consideration for the January 2006 California settlement includes an agreement that Sempra LNG would sell to the Sempra Utilities, subject to annual CPUC approval, regasified liquefied natural gas (LNG) for a period of 18 years beginning in 2011 at the California border index price minus $0.02 per million British thermal units (MMBtu).
- Under the terms of the January 2006 settlements, $83 million was paid in August 2006, $83 million was paid in August 2007, and $25.8 million was paid in August 2008. Installments of $24.8 million will be paid on each successive anniversary of the closing date (August 2008) through the seventh anniversary of the closing date. Under the terms of the City of Los Angeles settlement, $8.5 million was paid in April 2007. 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, 6 percent was used to approximate our average cost of financing.
- In September 2006, the Clark County District Court approved the Nevada settlement. In July 2008, the California Attorney General and the DWR dismissed their appeal of the July 2006 San Diego County Superior Court order approving the California settlement, and all of the settlements became final in August 2008.

Natural Gas Cases

In April 2003, Sierra Pacific Resources and its utility subsidiary Nevada Power filed a lawsuit in the U.S. District Court in Nevada

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

against major natural gas suppliers, including the Sempra Utilities. The lawsuit claimed that the defendants conspired to manipulate and inflate the prices that Nevada Power had to pay for its natural gas by 1) preventing the construction of natural gas pipelines to serve Nevada and other Western states, and 2) reporting artificially inflated prices to trade publications. In December 2008, we paid $700,000 to settle the case, which has now been dismissed.

Five cases against the Sempra Utilities and various other companies are pending in the U.S. District Court in Nevada. Plaintiffs claim that energy prices were unlawfully manipulated 1) by reporting artificially inflated natural gas prices to trade publications and 2) by entering into deceptive transactions such as wash trades and churning transactions. In January 2009, we entered into a settlement agreement in which we agreed to pay $2 million to resolve these cases.

NATURAL GAS CONTRACTS

SoCalGas has the responsibility for procuring natural gas for both SDG&E's and SoCalGas' core customers in a combined portfolio. Total payments under natural gas contracts were:

	Years ended December 31,		
(Dollars in millions)	2008	2007	2006
SDG&E	12	390	380

PURCHASED-POWER CONTRACTS

For 2009, SDG&E expects to receive 27 percent of its customer power requirements from DWR allocations. The remaining requirements are expected to be met as follows:

- SONGS: 18 percent
- Long-term contracts: 18 percent (of which 9 percent is provided by renewable energy contracts expiring on various dates through 2025)
- Other SDG&E-owned generation (including Palomar) and tolling contracts (including OMEC): 22 percent
- Spot market purchases: 15 percent

The long-term contracts expire on various dates through 2035.

At December 31, 2008, the estimated future minimum payments under SDG&E's long-term purchased-power contracts (not including the DWR allocations) were:

(Dollars in millions)	
2009	$ 342
2010	249
2011	252
2012	250
2013	245
Thereafter	1,676
Total minimum payments*	$ 3,014

* *Excludes amounts related to OMEC as it is consolidated at SDG&E.*

The payments represent capacity charges and minimum energy purchases. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Excluding DWR-allocated contracts, total payments under the contracts were:

- $393 million in 2008
- $351 million in 2007
- $344 million in 2006

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

LEASES

SDG&E has operating leases on real and personal property expiring at various dates from 2009 to 2045. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 4 percent to 6 percent at SDG&E. The rentals payable under these leases may increase by a fixed amount each year or by a percentage of a base year, and most leases contain extension options that we could exercise.

The Sempra Utilities had a master lease agreement with GE Capital, which was terminated in November 2008 and contained a repayment provision for any outstanding amounts to be repaid within twelve months. At December 31, 2008, this amount was $38 million for SDG&E. A new master lease agreement was entered into with RBS Asset Finance, Inc., with an aggregate maximum limit of $100 million combined for the Sempra Utilities.

Rent expense totaled:

	Years ended December 31,		
(Dollars in millions)	2008	2007	2006
SDG&E	25	24	23

At December 31, 2008, the minimum rental commitments payable in future years under all non-cancelable leases were as follows:

(Dollars in millions)	SDG&E
2009	$ 24
2010	22
2011	21
2012	19
2013	16
Thereafter	59
Total future rental commitments	$ 161

CONSTRUCTION AND DEVELOPMENT PROJECTS

The following is a summary of contractual commitments and contingencies related to the construction projects. At December 31, 2008, SDG&E has commitments to make payments in 2009 of:

- $48 million for implementation of the Smart Metering Program
- $28 million for replacement of the SONGS steam generators

GUARANTEES

As of December 31, 2008, SDG&E 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 will lead to increased costs for spent fuel storage. This cost will be recovered through SONGS revenue unless SDG&E is able to recover the increased cost from the federal government.

ENVIRONMENTAL ISSUES

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Our operations are subject to federal, state and local environmental laws. We also are subject to regulations related to hazardous wastes, air and water quality, land use, solid waste disposal and the protection of wildlife. These laws and regulations require that we investigate and correct the effects of the release or disposal of materials at sites associated with our past and our present operations. These sites include those at which we have been identified as a Potentially Responsible Party (PRP) under the federal Superfund laws and similar state laws.

In addition, we are required to obtain numerous governmental permits, licenses and other approvals to construct facilities and operate our businesses. The related costs of environmental monitoring, pollution control equipment, cleanup costs, and emissions fees are significant. Increasing national and international concerns regarding global warming and mercury, carbon dioxide, nitrogen oxide and sulfur dioxide emissions could result in requirements for additional pollution control equipment or significant emissions fees or taxes. SDG&E’s costs to operate their facilities in compliance with these laws and regulations generally have been recovered in customer rates.

We generally capitalize the significant costs we incur to mitigate or prevent future environmental contamination or extend the life, increase the capacity, or improve the safety or efficiency of property used in current operations. The following table shows (in millions) our capital expenditures in order to comply with environmental laws and regulations:

	Years ended December 31,		
	2008	2007	2006
SDG&E	18	11	14

Increases from 2007 to 2008 are primarily due to spending related to the Sunrise Powerlink and the Miramar II peaking plant, . We have not identified any significant environmental issues outside the United States. Over the next five years, SDG&E expects to incur costs of approximately $190 million for environmental mitigation measures associated with the Sunrise Powerlink construction project.

At SDG&E, 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 us or resolved during the last three years include 1) investigation and remediation of the Sempra Utilities' manufactured-gas sites, 2) cleanup of third-party waste-disposal sites used by the Sempra Utilities at sites which have been identified as PRPs and 3) mitigation of damage to the marine environment caused by the cooling-water discharge from SONGS. The requirements for enhanced fish protection and restoration of 150 acres of coastal wetlands for the SONGS mitigation are in process and a 150-acre artificial reef was completed in 2008. The table below shows the status at December 31, 2008, of SDG&E’s manufactured-gas sites and the third-party waste-disposal sites identified as PRPs:

	# Sites Completed	# Sites In Process
SDG&E		
Manufactured-gas sites	3	--
Third-party waste-disposal sites	1	1

We record environmental liabilities at undiscounted amounts when our liability is probable and the costs can be reasonably estimated. In many cases, however, investigations are not yet at a stage where we can determine whether we are liable or, if the liability is probable, to reasonably estimate the amount or range of amounts of the costs. Estimates of our liability are further subject to uncertainties such as the nature and extent of site contamination, evolving cleanup standards and imprecise engineering evaluations. We review our accruals periodically and, as investigations and cleanup proceed, we make adjustments as necessary. The following table shows (in millions) our accrued liabilities for environmental matters at December 31, 2008:

	Manufactured Gas Sites	Waste Disposal Sites (PRP*)	Former Fossil-Fueled Power Plants	Other Hazardous Waste Sites	Total
SDG&E**	$ 0.3	$ 0.2	$ 6.3	$ 1.0	$ 7.8

* *For which we have been identified as a Potentially Responsible Party*
** *Does not include SDG&E's liability for SONGS marine mitigation.*

Name of Respondent San Diego Gas & Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report 2008/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

We expect to pay the majority of these accruals over the next three 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 damage to the marine environment caused by the cooling-water discharge from SONGS. At December 31, 2008, SDG&E's share of the estimated mitigation costs remaining to be spent through 2050 is $19.7 million, which is recoverable in rates.

NUCLEAR INSURANCE

SDG&E and the other owners of SONGS have insurance to cover claims from nuclear liability incidents arising at SONGS. This insurance provides $300 million in coverage limits, the maximum amount available, including coverage for acts of terrorism. In addition, the Price-Anderson Act provides for up to $12.2 billion of secondary financial protection (SFP). If a nuclear liability loss occurring at any U.S. licensed/commercial reactor exceeds the $300 million insurance limit, all nuclear reactor owners could be required to contribute to the SFP. SDG&E’s contribution would be up to $47 million. This amount is subject to an annual maximum of $7 million, unless a default occurs by any other SONGS owner. If SFP is insufficient to cover the liability loss, SDG&E could be subject to an additional assessment.

The SONGS owners, including SDG&E, also have $2.75 billion of nuclear property, decontamination, and debris removal insurance. In addition, the SONGS owners have up to $490 million insurance coverage for outage expenses and replacement power costs due to accidental property damage. This coverage is limited to $3.5 million per week for the first 52 weeks, then $2.8 million per week for up to 110 additional weeks. There is a 12-week waiting period deductible. These insurance coverages are provided through a mutual insurance company. Insured members are subject to retrospective premium assessments. SDG&E could be assessed up to $8.5 million.

The nuclear property insurance program includes an industry aggregate loss limit for non-certified acts of terrorism (as defined by the Terrorism Risk Insurance Act). The industry aggregate loss limit for property claims arising from non-certified acts of terrorism is $3.24 billion. This is the maximum amount that will be paid to insured members who suffer losses or damages from these non-certified terrorist acts.

CONCENTRATION OF CREDIT RISK

We maintain credit policies and systems to manage our 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. We grant credit to utility customers and counterparties, substantially all of whom are located in our service territory, which covers all of San Diego County and an adjacent portion of Orange County.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(18,733,960)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		4,363,340		
4	Total (lines 2 and 3)		4,363,340		
5	Balance of Account 219 at End of Preceding Quarter/Year		(14,370,620)		
6	Balance of Account 219 at Beginning of Current Year		(14,370,620)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		3,522,439		
9	Total (lines 7 and 8)		3,522,439		
10	Balance of Account 219 at End of Current Quarter/Year		(10,848,181)		

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(18,733,960)	[redacted]	[redacted]
2				[redacted]	[redacted]
3	(1,098,474)		3,264,866	[redacted]	[redacted]
4	(1,098,474)		3,264,866	287,725,061	290,989,927
5	(1,098,474)		(15,469,094)	[redacted]	[redacted]
6	(1,098,474)		(15,469,094)	[redacted]	[redacted]
7				[redacted]	[redacted]
8	(227,381)	(166,390)	3,128,668	[redacted]	[redacted]
9	(227,381)	(166,390)	3,128,668	343,894,417	347,023,085
10	(1,325,855)	(166,390)	(12,340,426)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (f) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	9,295,514,477	7,650,327,394
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	9,295,514,477	7,650,327,394
9	Leased to Others		
10	Held for Future Use	2,973,017	2,973,017
11	Construction Work in Progress	412,030,658	263,837,712
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,710,518,152	7,917,138,123
14	Accum Prov for Depr, Amort, & Depl	4,403,390,271	3,592,884,196
15	Net Utility Plant (13 less 14)	5,307,127,881	4,324,253,927
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,176,937,635	3,530,401,256
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	226,452,636	62,482,940
22	Total In Service (18 thru 21)	4,403,390,271	3,592,884,196
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,403,390,271	3,592,884,196

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report End of 2008/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,149,828,363				495,358,720	3
					4
					5
					6
					7
1,149,828,363				495,358,720	8
					9
					10
12,349,680				135,843,266	11
					12
1,162,178,043				631,201,986	13
516,503,983				294,002,092	14
645,674,060				337,199,894	15
					16
					17
509,575,714				136,960,665	18
					19
					20
6,928,269				157,041,427	21
516,503,983				294,002,092	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
516,503,983				294,002,092	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 14 Column: b

Reclassification of 2008 Accum. Provision for Depreciation and Amortization for Ratemaking

Accumulated Provision for Depreciation and Amortization Classified
in Accordance with FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	Accumulated Prov. Per Book	Accumulated Prov. Ratemaking
Electric	3,592,884,196	-
Intangible Plant	-	24,264,198
Steam Production Plant	-	51,431,534
Nuclear Production Plant	-	1,711,043,014
Other Production Plant	-	16,453,385
Transmission Plant	-	461,527,151
Distribution Plant	-	1,724,646,829
General Plant	-	67,200,854
FAS 143 Steam Production	-	4,088,652
FAS 143 Nuclear Production	-	(450,898,228)
FAS 143/FIN 47 Electric	-	(16,873,193)
Total Electric	**3,592,884,196**	**3,592,884,196**
Gas	**516,503,983**	**516,503,983**
Common	**294,002,092**	**294,002,092**
Total Ratemaking Accumulated Provision-2008	**4,403,390,271***	**4,403,390,271***
Total Wtd. Avg. Accum. Provision for 2008-Transmission Plant		**449,668,791**

*Line 14 of FERC Form 1, pages 200-201 for EOY 2008.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Reclassification of 2007 Accum. Provision for Depreciation and Amortization for Ratemaking

	Accumulated Prov. Per Book	Accumulated Prov. Ratemaking
Electric	3,470,856,151	-
Intangible Plant	-	21,540,738
Steam Production	-	40,721,561
Nuclear Production	-	1,832,666,722
Other Production	-	13,614,550
Transmission	-	438,098,681
Distribution	-	1,646,707,877
General Plant	-	61,633,409
FAS 143 Steam Production	-	4,084,040
FAS 143 Nuclear Production	-	(580,496,923)
FIN 47 Transmission Plant	-	(3,823,488)
FIN 47 Distribution Plant	-	(3,891,016)
Total Electric	**3,470,856,151**	**3,470,856,151**
Gas	**462,174,335**	**462,174,335**
Common	**284,193,453**	**284,193,453**
Total Ratemaking Provision	**4,217,223,939***	**4,217,223,939***
Total Wtd. Avg. Accum. Provision for 2007-Transmission Plant		**426,530,274**

*Line 14 of FERC Form 1, pages 200-201 for EOY 2007.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	18,623,925	17,196,220
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	18,623,925	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	68,199,160	
10	SUBTOTAL (Total 8 & 9)	68,199,160	
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	50,142,988	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	36,680,097	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	29,339,725	6,480,420	2
			3
			4
			5
		6,480,420	6
			7
			8
-29,339,725		97,538,885	9
		97,538,885	10
			11
			12
-12,676,949		62,819,937	13
		41,199,368	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 202 Line No.: 2 Column: e

Transfer of cost from fuel in process to fuel in reactor.

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	222,841	
4	(303) Miscellaneous Intangible Plant	26,878,263	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	27,101,104	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	40,899,464	1,879,705
10	(312) Boiler Plant Equipment	115,839,127	45,191
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	97,698,061	1,776,091
13	(315) Accessory Electric Equipment	33,364,110	24,789
14	(316) Misc. Power Plant Equipment	18,950,591	37,693
15	(317) Asset Retirement Costs for Steam Production	115,379	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	321,393,250	3,763,469
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	283,677	
19	(321) Structures and Improvements	268,718,936	3,536,939
20	(322) Reactor Plant Equipment	393,511,631	
21	(323) Turbogenerator Units	137,756,920	603,865
22	(324) Accessory Electric Equipment	166,938,296	
23	(325) Misc. Power Plant Equipment	258,022,543	13,990,860
24	(326) Asset Retirement Costs for Nuclear Production	112,138,651	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,337,370,654	18,131,664
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	145,904	
38	(341) Structures and Improvements	4,421,921	298,531
39	(342) Fuel Holders, Products, and Accessories	15,295,980	
40	(343) Prime Movers	20,824,413	
41	(344) Generators	163,319,936	27,485,322
42	(345) Accessory Electric Equipment	9,103,734	
43	(346) Misc. Power Plant Equipment	359,058	
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	213,470,946	27,783,853
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,872,234,850	49,678,986

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	96,316,922	805,504
49	(352) Structures and Improvements	80,918,914	13,081,165
50	(353) Station Equipment	528,563,033	78,904,098
51	(354) Towers and Fixtures	104,682,106	3,665,791
52	(355) Poles and Fixtures	126,723,541	11,161,386
53	(356) Overhead Conductors and Devices	215,753,429	15,503,552
54	(357) Underground Conduit	105,508,143	19,752,734
55	(358) Underground Conductors and Devices	91,483,794	10,513,530
56	(359) Roads and Trails	21,628,728	753,158
57	(359.1) Asset Retirement Costs for Transmission Plant	1,454,242	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,373,032,852	154,140,918
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	83,587,126	1,121,666
61	(361) Structures and Improvements	3,271,362	22,091
62	(362) Station Equipment	305,374,354	14,533,432
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	395,120,520	23,118,230
65	(365) Overhead Conductors and Devices	308,662,885	18,973,545
66	(366) Underground Conduit	770,992,532	52,494,886
67	(367) Underground Conductors and Devices	1,038,237,800	56,880,516
68	(368) Line Transformers	402,768,675	32,762,905
69	(369) Services	363,217,905	18,792,738
70	(370) Meters	128,200,253	7,657,876
71	(371) Installations on Customer Premises	6,074,857	188,414
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	23,518,825	633,360
74	(374) Asset Retirement Costs for Distribution Plant	2,186,179	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,831,213,273	227,179,659
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	7,511,040	
87	(390) Structures and Improvements	29,317,937	235,169
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	175,979	
90	(393) Stores Equipment	54,331	
91	(394) Tools, Shop and Garage Equipment	13,578,003	1,738,708
92	(395) Laboratory Equipment	300,344	
93	(396) Power Operated Equipment	92,162	
94	(397) Communication Equipment	100,620,725	7,200,238
95	(398) Miscellaneous Equipment	431,093	31,467
96	SUBTOTAL (Enter Total of lines 86 thru 95)	152,081,614	9,205,582
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	152,081,614	9,205,582
100	TOTAL (Accounts 101 and 106)	7,255,663,693	440,205,145
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	7,255,663,693	440,205,145

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			222,841		3
			26,878,263		4
			27,101,104		5
					6
					7
			14,526,518		8
			42,779,169		9
	-1		115,884,317		10
					11
49,062	1		99,425,091		12
			33,388,899		13
			18,988,284		14
			115,379		15
49,062			325,107,657		16
					17
			283,677		18
			272,255,875		19
683,082	-1		392,828,548		20
181,365	1		138,179,421		21
87,569	1		166,850,728		22
1,939,337			270,074,066		23
	14,414,483		126,553,134		24
2,891,353	14,414,484		1,367,025,449		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			145,904		37
			4,720,452		38
			15,295,980		39
			20,824,413		40
4,617,232		-713,336	185,474,690		41
	1	713,336	9,817,071		42
			359,058		43
					44
4,617,232	1		236,637,568		45
7,557,647	14,414,485		1,928,770,674		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
660,275			96,462,151		48
148,522		1,189,519	95,041,076		49
996,899		-1,184,461	605,285,771		50
47,688		-300,041	108,000,168		51
2,918,403	-1	125,312	135,091,835		52
904,122		115,052	230,467,911		53
341		-207,802	125,052,734		54
31,682		-10,048	101,955,594		55
		265,528	22,647,414		56
	334,680		1,788,922		57
5,707,932	334,679	-6,941	1,521,793,576		58
					59
95,250	1		84,613,543		60
18,527	-1	29,968	3,304,893		61
909,648		-989,720	318,008,418		62
					63
8,833,619		12,000	409,417,131		64
4,690,049			322,946,381		65
7,724,410			815,763,008		66
8,588,278			1,086,530,038		67
10,745,643			424,785,937		68
3,257,789			378,752,854		69
1,345,665			134,512,464		70
82,160			6,181,111		71
					72
829,237			23,322,948		73
	1,254,437		3,440,616		74
47,120,275	1,254,437	-947,752	4,011,579,342		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			7,511,040		86
43,324			29,509,782		87
					88
			175,979		89
			54,331		90
327,218			14,989,493		91
8,013			292,331		92
			92,162		93
780,636		954,693	107,995,020		94
			462,560		95
1,159,191		954,693	161,082,698		96
					97
					98
1,159,191		954,693	161,082,698		99
61,545,045	16,003,601		7,650,327,394		100
					101
					102
					103
61,545,045	16,003,601		7,650,327,394		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 104 Column: g

Reclassification of 2008 Electric Plant-in-Service for Ratemaking
Plant in Service Classified in Accordance with FERC Seven Factor Test
In accordance with Guidelines in FERC Order 888

	BOY 2008	EOY 2008
Intangible Plant	26,878,263	26,878,263
Steam Production Plant	332,461,530	336,175,937
Nuclear Production Plant	1,231,175,756	1,246,416,068
Other Production Plant	214,925,042	238,091,663
Transmission Plant	1,328,623,672	1,474,554,199
Distribution Plant	3,853,623,365	4,035,230,517
General Plant	152,081,614	161,082,696
FAS 143 Steam Production	115,379	115,379
FAS 143 Nuclear Production	112,138,651	126,553,134
FIN 47 Transmission Plant	1,454,242	1,788,922
FIN 47 Distribution Plant	2,186,179	3,440,616
Total Ratemaking Electric Plant-in-Service	7,255,663,693 *	7,650,327,394 **

*Line 104 of FERC Form 1, page 206, col. b.

**Line 104 of FERC Form 1, page 207, col. g.

Total Wtd. Avg. Plant Balance for 2008 - Steam Production	335,402,504
Total Wtd. Avg. Plant Balance for 2008 - Nuclear Production	1,237,905,237
Total Wtd. Avg. Plant Balance for 2008 - Other Production	217,747,647
Total Wtd. Avg. Plant Balance for 2008 - Transmission Plant	1,363,828,729

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3	Electric Transmission Plant:			
4				
5	Torrey Pines/Sorrento Mesa	03/31/2005	12/31/2012	1,785,268
6				
7	Jamul Land	12/31/2006	12/31/2013	1,160,128
8				
9	Other Land Assets	01/31/2007	12/31/2013	27,621
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			2,973,017

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SONGS UNIT 2 & 3	46,673,898
2	SONGS COMMON FACILITIES	4,287,917
3	MIRAMAR PLANT OPERATIONAL ENHANCEMENTS	3,308,931
4	PALOMAR PLANT OPERATIONAL ENHANCEMENTS	1,253,314
5	MEF II	26,926,644
6	SONGS 2 & 3 STEAM GENERATOR REPLACEMENT	59,775,712
7	THERMAL ENERGY STORAGE TANK	622,000
8	TRANSMISSION PROJECTS	3,985,682
9	ELECTRIC TRANSMISSION RELOCATION PROJECTS *	-5,044,514
10	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	1,998,583
11	RENEWAL OF TRANSMISSION LINE EASEMENTS	1,031,050
12	ELECTRIC TRANS. STREET & HIGHWAY RELOCATIONS *	-162,808
13	ELECTRIC TRANSMISSION LINE PROJECTS	126,851
14	ORANGE COUNTY LONG RANGE PLAN	1,024,291
15	ENCINA-PENASQUITOS 230KV LINE	7,593,796
16	LOOP-IN TL13825 - SHADOWRIDGE	505,103
17	SOUTH BAY SUBSTATION RELOCATION	1,224,191
18	TL651 WABASH-NATIONAL CITY LOOP-IN	751,922
19	NAVAL STATION METERING - 69KV	2,815,059
20	NAVAL STATION METERING - 12KV CAPACITOR BANKS	1,282,452
21	CAMP PENDLETON TOWER LIGHTING	609,868
22	JACUMBA SUBSTATION	2,494,592
23	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	477,328
24	TRANSMISSION INFRASTRUCTURE IMPROVEMENTS	13,339,941
25	OTAY METRO POWERLOOP-MIGUEL TAP	1,943,629
26	MIGUEL SUBSTATION - ACCESS ROAD SLOPE REPAIR	428,154
27	TL 627 SW POLE REPLACEMENTS	878,806
28	TL13815 - BAYFRONT CONVERSION	2,927,596
29	TL 634 SW POLE REPLACEMENTS	11,370,160
30	BULL MOOSE ENERGY OF SAN DIEGO-INTERCONNECTION	194,397
31	TL 681 FELICITA-ASH-VALLEY CENTER SW POLE REPLACEMENT	1,563,782
32	TL 683 LILAC-RINCON SW POLE REPLACEMENTS & RECOND	342,988
33	TL 635 LOS COCHES-CREELMAN SW POLE REPLACEMENTS	840,892
34	TL 6930/6945 ESCONDIDO TO OLIVENHAIN-SW POLE REPLACEMENT	178,952
35	SILVERGATE SUBSTATION - NEW 138/69KV	736,125
36	TRANSMISSION SYSTEM AUTOMATION	1,899,844
37	OTAY MESA POWER PURCHASE AGREEMENT TRANSMISSION PROJ.	392,190
38	DISTRIBUTION SUBSTATION	2,990,510
39	ELECTRIC DISTRIBUTION STREET/HWY RELOCATION	264,625
40	CONVERSION FROM OH TO UG RULE 20A	11,626,152
41	CONVERSION FROM OH TO UG RULE 20B, 20C *	-298,484
42	CITY OF SAN DIEGO SURCHARGE PROGRAM (20SD)	4,416,428
43	TOTAL	263,837,712

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	UG RESIDENTIAL NEW BUSINESS	1,700,861
2	UG NON-RESIDENTIAL NEW BUSINESS *	-390,923
3	NEW BUSINESS INFRASTRUCTURE	726,382
4	CUSTOMER REQUESTED UPGRADES AND SERVICES *	-950,597
5	MANAGEMENT OF OH DISTRIBUTION SERVICE	1,563,941
6	REACTIVE SMALL CAPITAL PROJECTS	558,703
7	REPLACEMENT OF UNDERGROUND CABLES	1,696,271
8	WOOD POLE REINFORCEMENT & REPLACEMENT PROGRAM *	-518,104
9	DISTRIBUTION SUBSTATION PROJECTS CAPACITY	743,619
10	DISTRIBUTION CIRCUIT RELIABILITY CONSTRUCTION	2,031,976
11	POWER QUALITY PROGRAM	420,519
12	TELEGRAPH CANYON-NEW 12KV CIRCUIT 1225	863,635
13	MELROSE SUBSTATION-NEW 12KV CIRCUIT 821	1,909,208
14	DISTRIBUTION AUTOMATION	1,336,394
15	STATION B-EXTENSION OF CIRCUIT 108	306,663
16	NEW 12KV CIRCUITS C1434 & C1435	135,439
17	LILAC BANK REPLACEMENT & NEW CIRCUIT C355	593,942
18	REPLACEMENT OF LIVE FRONT EQUIPMENT	122,494
19	DISTRIBUTION SYSTEM CAPACITY IMPROVEMENT	2,186,146
20	C248 OL-NEW CIRCUIT LOS COCHES SUBSTATION	2,130,883
21	SMART METER PROJECT-ELECTRIC	591,984
22	OTAY SUBSTATION REBUILD	3,670,104
23	MESA HEIGHTS-INSTALL 3RD BANK & 3 NEW 12KV CIRCUITS	356,517
24	MIRA SORRENTO SUBSTATION - NEW CIRCUITS C1442 TO C1446	426,147
25	ARTESIAN SUB-ADD 2ND BANK & NEW CIRCUIT 1104	2,083,542
26	SUSTAINABLE COMMUNITY ENERGY SYSTEMS	1,089,688
27	C1138: NEW SN CIRCUIT TO OFFLOAD C396	1,409,731
28	REPLACE OBSOLETE SUBSTATION EQUIPMENT	3,159,105
29	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLACEMENT & MANHOLE REPAIR	2,162,892
30	STRUCTURES & IMPROVEMENTS BLANKET	391,849
31	COMMON PLANT BLANKET-INFRASTRUCTURE & RELIABILITY	599,394
32	MIGUEL SUBSTATION SECURITY IMPROVEMENTS	970,861
33	ENERGY MANAGEMENT SYSTEM - SMALL PROJECTS	772,526
34	NETWORK/TELECOM HARDWARE - RELIABILITY	267,571
35	ELECTRIC TRANSMISSION SOFTWARE - MANDATED	982,824
36	OPEX 20/20	3,996,955
37	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	3,335,247
38	MINOR PROJECTS (LESS THAN $100,000)	804,774
39	RESEARCH, DEVELOPMENT & DEMONSTRATION	
40		
41	ANNUAL CHANGES IN PROJECT BALANCES ARE DUE TO COMPLETION OF	
42	SEPARATE SEGMENTS OF THE BUDGET	
43	TOTAL	263,837,712

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	*CUSTOMER CONTRIBUTION IN AID OF CONSTRUCTION EXCEEDS	
2	PROJECT COSTS TO DATE	
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	263,837,712

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,412,983,105	3,412,983,105		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	223,802,660	223,802,660		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	223,802,660	223,802,660		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	60,788,709	60,788,709		
13	Cost of Removal	35,849,834	35,849,834		
14	Salvage (Credit)	2,974,444	2,974,444		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	93,664,099	93,664,099		
16	Other Debit or Cr. Items (Describe, details in footnote):	-133,165,030	-133,165,030		
17					
18	Book Cost or Asset Retirement Costs Retired	120,444,620	120,444,620		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,530,401,256	3,530,401,256		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	54,809,831	54,809,831		
21	Nuclear Production	1,253,917,356	1,253,917,356		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	16,322,733	16,322,733		
25	Transmission	459,284,152	459,284,152		
26	Distribution	1,678,866,330	1,678,866,330		
27	Regional Transmission and Market Operation				
28	General	67,200,854	67,200,854		
29	TOTAL (Enter Total of lines 20 thru 28)	3,530,401,256	3,530,401,256		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) _ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 3 Column: c

Depreciation Provision - Electric only (Line 10, Page 219)	$ 223,802,660
Depreciation Provision - Common Alloc. to Elec. (Line 11, Page 336)	18,595,336
Depreciation Provision (Line 6, Col. E, Page 115)	$ 242,397,996

Schedule Page: 219 Line No.: 10 Column: c

Includes current provision for SONGS Decommissioning of	$ 9,350,000

Schedule Page: 219 Line No.: 12 Column: c

Book Cost of Plant Retired (Line 12, Col. B, Page 219)	$(60,788,709)
Total Plant Retired (Line 104, Col. D, Page 207)	61,545,045
Adj. for Land & Intangible Retirements not impacting A/C 108	(755,525)
Adj. for Net Book Value of Plant Retired to Gain on Sale	(811)
Difference:	$ 0

Schedule Page: 219 Line No.: 16 Column: c

SONGS Decommissioning - Current Year Trust Income (Loss)	$(133,165,030)
Transfers of reserves between asset classes	0
Other Debit and Credit Items (Line 16, Page 219)	$(133,165,030)

Schedule Page: 219 Line No.: 21 Column: c

Includes Accumulated Provisions for SONGS Decommissioning in the amount of	$ 521,936,451

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	SDG&E Funding LLC	07/01/97		3,290,000
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	3,290,000

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
				42

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 1 Column: g

SDG&E Funding LLC was dissolved in 2008. There was no gain or loss associated with this transaction.

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	1,709,849	2,048,779	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	8,614,723	4,899,901	ELECTRIC/GAS
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			COMMON
11	Assigned to - Other (provide details in footnote)	53,293,717	54,534,088	COMMON
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	63,618,289	61,482,768	
13	Merchandise (Account 155)			COMMON
14	Other Materials and Supplies (Account 156)			COMMON
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	63,618,289	61,482,768	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 20 Column: c

Reclassification of FERC Form 1 Materials & Supplies for Ratemaking

Materials and Supplies Classified In Accordance with Guidelines in FERC Order 888

	BOY 2008	EOY 2008
Total Materials and Supplies	63,618,289*	61,482,768*
As Assigned to Department for Ratemaking		
Electric Department	60,824,108	58,468,261
Gas Department	2,794,181	3,014,508
Less Line 5 (Construction Estimate)		
Electric Department	(1,690,690)	(2,016,402)
Gas Department	(19,159)	(32,377)
Total Allowable Materials and Supplies		
Electric Department	**59,133,418**	**56,451,859**
Gas Department	2,775,022	2,982,131
Total Allowable M&S per FERC Formula	61,908,440**	59,433,989**
Total Wtd. Average Electric M&S for 2008		57,361,647

*Line 20 of FERC Form 1, page 227.

**Line 20 minus Line 5 of FERC Form 1, page 227.

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2009 No. (d)	2009 Amt. (e)
1	Balance-Beginning of Year	1,495.00		1,861.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,062.00		2,063.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Transfer to Boardman	-1,688.00			
10	Transfer to Palomar	-8.00			
11	Transfer to Miramar				
12					
13					
14					
15	Total	-1,696.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,861.00		3,924.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2010		2011		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
3,924.00		18,881.00		33,838.00		59,999.00		1
								2
								3
14,957.00		14,957.00		353,590.00		387,629.00		4
								5
								6
								7
								8
						-1,688.00		9
						-8.00		10
								11
								12
								13
								14
						-1,696.00		15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
18,881.00		33,838.00		387,428.00		445,932.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23	Valley Rainbow Project	18,926,938		407	1,892,694	8,990,296
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	18,926,938			1,892,694	8,990,296

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 230 Line No.: 23 Column: a

The authorization to utilize Account 182.2 and to amortize the balance was provided by FERC in Docket No. ER03-601-000 issued May 2, 2003, which approved SDG&E's revised Transmission Owner Tariff (TO Tariff) to become effective October 1, 2003. Based on the terms of the TO Tariff, the amortization period will be the 10-year period beginning October 2003 and ending September 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Taxes Recoverable in Rates	359,713,190	54,878,251			414,591,441
2	Amortized Over Various Lives					
3						
4	Post Retirement Benefits Other than Pension	71,615,729	15,130,540			86,746,269
5						
6	Workers Compensation (IBNR)	6,788,000		228	893,000	5,895,000
7						
8	Employer's Accounting for Postemployment Benefits	4,740,000	396,999			5,136,999
9						
10	Environmental Clean-Up	470,280	293,820			764,100
11						
12	Balancing Account Undercollections	157,305,758	92,421,904			249,727,662
13						
14	Pension Benefits	90,683,439	215,835,278			306,518,717
15						
16	SONGS Mitigation	11,014,000	8,709,000			19,723,000
17						
18	Electric Derivatives	350,542,054	24,149,582			374,691,636
19						
20	Gas Derivatives	18,945,758		244	7,366,922	11,578,836
21						
22	Contribution to City of Escondido	2,392,161		253	82,062	2,310,099
23	(20 year life, starting 2006)					
24						
25	Asset Retirement Obligations	22,882,026	377,241			23,259,267
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,097,092,395	412,192,615		8,341,984	1,500,943,026

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	SDG&E Shelf Registration	813,661	282,224	181	185,823	910,062
2						
3	Southwest Powerlink Deferred					
4	per CPUC					
5	(Amortization 1/86 - 12/23)	489,706		406	15,744	473,962
6						
7	Radio Sites Lease	366,527		931	95,604	270,923
8						
9	Industrial Development Bonds	64,811				64,811
10						
11	Miramar Energy Facility II	16,518,325		107	16,518,325	
12						
13	Mitigation Fund	250,000	500,000			750,000
14						
15	On Bill Financing Loans	113,832	553,523			667,355
16						
17	Fleet Leaseback Costs		255,520			255,520
18						
19	System Recovery		69,060			69,060
20						
21	Solar Photovoltaic		55,294			55,294
22						
23	Miscellaneous Other	116,068		various	108,962	7,106
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	18,732,930				3,524,093

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Federal	118,819,758	150,153,601
3	State	52,279,145	61,691,415
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	171,098,903	211,845,016
9	Gas		
10	Federal	17,567,004	21,646,460
11	State	3,537,334	4,807,504
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	21,104,338	26,453,964
17	Other (Specify): Non Utility	14,855,733	18,812,823
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	207,058,974	257,111,803

Notes

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 2 Column: c

Electric balance in account 190 at end of year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $352,156.

Schedule Page: 234 Line No.: 17 Column: c

Balance includes non-operating deferred income taxes of $14,091,423 and balance sheet reclasses of $4,721,400.

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	COMMON (1)	255,000,000	2.50	
2	TOTAL COMMON	255,000,000		
3				
4	CUMULATIVE PREFERRED STOCK	1,375,000		
5				
6	5% SERIES		20.00	24.00
7	4.50% SERIES		20.00	21.20
8	4.40% SERIES		20.00	21.00
9	4.60% SERIES		20.00	20.25
10				
11				
12	PREFERENCE STOCK (CUMULATIVE)			
13				
14	WITHOUT PAR	10,000,000		
15				
16	$1.70 SERIES		25.00	25.60
17	$1.82 SERIES		25.00	26.00
18				
19				
20	TOTAL PREFERRED	11,375,000		
21				
22	Note: All the Common Stock of San Diego Gas &			
23	Electric is owned by Enova Corporation and is			
24	not publicly traded. See San Diego Gas &			
25	Electric Company 2008 SEC Form 10-K for stock			
26	exchange information for San Diego Gas &			
27	Electric preferred and preference stock.			
28				
29	(1) There are 8,634,258 shares of Common Stock			
30	authorized to be issued by the California			
31	Public Utilities Commission which have not yet			
32	been issued by the Company as of December 31,			
33	2008.			
34				
35				
36				
37				
38				
39				
40				
41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
116,583,358	291,458,395					1
116,583,358	291,458,395					2
						3
						4
						5
375,000	7,500,000					6
300,000	6,000,000					7
325,000	6,500,000					8
373,770	7,475,400					9
						10
						11
						12
						13
						14
						15
1,400,000	35,000,000					16
640,000	16,000,000					17
						18
						19
3,413,770	78,475,400					20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 208 - None	
2		
3	ACCOUNT 209 - None	
4		
5	ACCOUNT 210 - None	
6		
7	ACCOUNT 211	
8	Assets Transferred from Sempra Energy	79,618,042
9	Equity Infusion from Sempra Energy	200,000,000
10	Total Account 211	279,618,042
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	279,618,042

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common	24,605,640
2		
3	Preferred, Cumulative:	
4	4.60%	53,319
5		
6	Preference, Cumulative:	
7	$1.70	464,567
8	$1.82	565,045
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	25,688,571

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACOUNT 221-BONDS		
2			
3	FIRST MORTGAGE BONDS		
4	6.8% Series KK Due 2015	14,400,000	819,642
5			83,952 D
6	5.00% and 5.25% Series OO Due 2027	250,000,000	1,615,079
7			
8	5.85% Series RR Due 2021	60,000,000	1,731,535
9			411,600 D
10	Var% Series VV Due 2034	43,615,000	1,195,663
11			
12	Var% Series WW Due 2034	40,000,000	1,097,030
13			
14	Var% Series XX Due 2034	35,000,000	960,647
15			
16	Var% Series YY Due 2034	24,000,000	659,704
17			
18	Var% Series ZZ Due 2034	33,650,000	923,358
19			
20	Var% Series AAA Due 2039	75,000,000	2,286,248
21			
22	5.35% Series BBB Due 2035	250,000,000	2,709,950
23			295,000 D
24	5.30% Series CCC Due 2015	250,000,000	2,085,426
25			497,500 D
26	6.00% Series DDD Due 2026	250,000,000	2,409,375
27			1,117,500 D
28	Var% Series EEE Due 2018	161,240,000	2,925,570
29			
30	6.125% Series FFF Due 2037	250,000,000	2,536,702
31			780,000 D
32	SUBTOTAL ACCOUNT 221	1,736,905,000	27,141,481
33	TOTAL	1,993,125,000	30,144,696

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	ACCOUNT 222-REACQUIRED BONDS-NONE		
3			
4	ACCOUNT 223 ADVANCES FROM ASSOCIATED COMPANIES-NONE		
5			
6	ACCOUNT 224-OTHER LONG-TERM DEBT		
7			
8	Unsecured Bonds-5.9% Series CPCFA96A	129,820,000	880,958
9			486,825 D
10	Unsecured-5.3%-Series CV96A	38,900,000	568,876
11			
12	Unsecured-5.50% Series CV96B	60,000,000	680,090
13			
14	Unsecured-4.9% Series CV97A	25,000,000	386,466
15			
16	Redeemable Preferred Stock, $1.7625 Series	2,500,000	
17			
18	SUBTOTAL ACCOUNT 224	256,220,000	3,003,215
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,993,125,000	30,144,696

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
12/01/91	06/01/15	12/01/91	06/01/15	14,400,000	979,200	4
						5
12/01/92	12/01/27	12/01/92	12/01/27	150,000,000	7,612,500	6
						7
06/29/93	06/01/21	06/29/93	06/01/21	60,000,000	3,510,000	8
						9
06/17/04	02/15/34	06/17/04	02/15/34	43,615,000	1,424,800	10
						11
06/17/04	02/15/34	06/17/04	02/15/34	40,000,000	1,271,864	12
						13
06/17/04	02/15/34	06/17/04	02/15/34	35,000,000	1,189,644	14
						15
06/17/04	01/01/34	06/17/04	01/01/34	24,000,000	771,270	16
						17
06/17/04	01/01/34	06/17/04	01/01/34	33,650,000	1,064,204	18
						19
06/17/04	05/01/39	06/17/04	05/01/39	75,000,000	2,751,102	20
						21
05/19/05	05/15/35	05/19/05	05/15/35	250,000,000	13,375,000	22
						23
11/17/05	11/15/15	11/17/05	11/15/15	250,000,000	13,250,000	24
						25
06/08/06	06/01/26	06/08/06	06/01/26	250,000,000	15,000,000	26
						27
09/21/06	07/01/18	09/21/06	07/01/18	161,240,000	4,609,690	28
						29
09/20/07	09/15/37	09/20/07	09/15/37	250,000,000	15,312,500	30
						31
				1,636,905,000	82,121,774	32
				1,890,625,000	96,367,854	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
06/01/96	06/01/14	06/01/96	06/01/14	129,820,000	7,659,380	8
						9
08/02/96	07/01/21	08/02/96	07/01/21	38,900,000	2,061,700	10
						11
11/21/96	12/01/21	11/21/96	12/01/21	60,000,000	3,300,000	12
						13
10/31/97	03/01/23	10/31/97	03/01/23	25,000,000	1,225,000	14
						15
						16
						17
				253,720,000	14,246,080	18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,890,625,000	96,367,854	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 32 Column: c

Expense	$23,955,929
Discount	3,185,552
ACCOUNT 221	$27,141,481

Schedule Page: 256.1 Line No.: 16 Column: a

Balance of $13,750,000 was recalled on 1/15/2008.

Schedule Page: 256.1 Line No.: 18 Column: c

Expense	$2,817,864
Discount	486,825
ACCOUNT 224	$3,304,689

Schedule Page: 256.1 Line No.: 23 Column: a

Item 2:

FERC authorization is not required on routine new issues.

Item 11:

Debt expenses related to various existing series were incurred in 2008. They are: Series CCC-$2,255, Series DDD-$30,771, Series EEE-$184,211 and Series FFF-$128,000.

Item 15:

Acct 221	$82,121,774
Acct 224	14,246,080
Total Page 257 (Column (i)	$96,367,854
Interest Swaps	658,000
Total Account 427 & 430	$97,025,854

Item 16:

In July 2008, SDG&E received authority from the California Public Utilities Commission to issue $687,000,000 of new debt in Decision 08-07-029. At December 31, 2008 the total remaining authority for new debt was $1,119,260,000.

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	343,894,417
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	24,885,596
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	315,007,971
11	Federal and State Income Taxes	126,511,010
12	Miscellaneous Accrual - Reversal / Payment	24,497,000
13	Other	37,236,604
14	Income Recorded on Books Not Included in Return	
15	Regulatory Balancing Accounts	-97,926,239
16	Allowance for Funds Used During Construction	-37,391,624
17	Deferred Construction Revenue	-7,788,313
18	Other	-4,333,774
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-427,207,265
21	Removal Costs	-29,963,205
22	Software Development Costs	-40,845,194
23	Percentage Repair Allowance	-14,205,568
24	Facts and Circumstance Repairs	-12,300,000
25	Other	-28,515,648
26		
27	Federal Tax Net Income	171,555,768
28	Show Computation of Tax:	
29	Federal Tax @ 35%	60,044,519
30	Deferred Taxes	88,322,194
31	Tax Credits and Other Adjustments (net)	-19,173,564
32		
33	Total Federal Income Tax	129,193,149
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 13 Column: b

Amortization and Interest Capitalized	$ 18,700,517
Amortization of Loss on Reacquired Debt	3,915,006
SERP	5,314,680
Environmental Liability - Reversal / Payment	780,877
Miscellaneous	8,525,524
	$ 37,236,604

Schedule Page: 261 Line No.: 18 Column: b

Keyman Life Insurance	$(2,948,849)
Workers' Compensation	(863,415)
Officers' Life Insurance	(521,510)
	$(4,333,774)

Schedule Page: 261 Line No.: 25 Column: b

Abandonment Loss	$(11,072,471)
Qualified Decommissioning Contributions	(9,350,000)
Property Tax / Ad Valorem	(2,563,798)
Section 199 Deduction - Palomar & Ramco	(1,241,732)
Miscellaneous	(4,287,647)
	$(28,515,648)

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	LOCAL:					
2	Ad Valorem (Note 1)			52,499,938	52,499,938	
3	Sales and Use (Note 2)	8,252		241,335	117,261	
4						
5						
6	SUBTOTAL	8,252		52,741,273	52,617,199	
7						
8	STATE:					
9	Franchise (Note 3)		21,897,455	25,747,303	19,828,019	-2,526,283
10	Unemployment (Note 4)	358,735		1,324,810	1,341,908	-14
11	Sales and Use (Note 2)	34,382		1,005,563	488,588	
12	Fuel Tax		12,290	7,695	8,168	
13						
14	SUBTOTAL	393,117	21,909,745	28,085,371	21,666,683	-2,526,297
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)		34,412,239	14,158,459	-16,522,559	4,575,197
18	Retirement (Note 4)	890,675		24,213,719	23,888,580	
19	Unemployment (Note 4)	114,817		448,420	300,097	
20	Medicare (Note 4)	372,696		6,822,019	6,927,313	14
21	Fuel Tax	2,285		5,846		
22						
23						
24	SUBTOTAL	1,380,473	34,412,239	45,648,463	14,593,431	4,575,211
25						
26	Other - Foreign Tax			28,303	28,303	
27						
28						
29						
30						
31						
32						
33	Note 1					
34						
35	Note 2					
36						
37	Note 3					
38						
39	Note 4					
40						
41	TOTAL	1,781,842	56,321,984	126,503,410	88,905,616	2,048,914

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		40,415,395			12,084,543	2
132,326					241,335	3
						4
						5
132,326		40,415,395			12,325,878	6
						7
						8
	13,451,888	22,373,938			3,373,365	9
341,623		485,033			839,777	10
551,357					1,005,563	11
	12,763				7,695	12
						13
892,980	13,464,651	22,858,971			5,226,400	14
						15
						16
	8,306,418	10,695,416			3,463,043	17
1,215,814		9,270,746			14,942,973	18
263,140		164,173			284,247	19
267,416		2,497,644			4,324,375	20
8,131					5,846	21
						22
						23
1,754,501	8,306,418	22,627,979			23,020,484	24
						25
					28,303	26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
2,779,807	21,771,069	85,902,345			40,601,065	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: i

Amount includes Ad Valorem taxes on SONGS in the amount of $1,768,134.

Schedule Page: 262 Line No.: 9 Column: f

Description	Adjustment Amount	FERC Acct 190	FERC Acct 283	FERC Acct 431
Balance Sheet Reclassifications Due to FIN 48 Liabilities	(5,288,462)	(12,287,839)	17,576,301	
Interest Expense Reclass Due to FIN 48 Implementation	2,762,179			(2,762,179)
Total	(2,526,283)	(12,287,839)	17,576,301	(2,762,179)

Schedule Page: 262 Line No.: 17 Column: e

2007 Extention Refund	$ (44,300,000)
IRS Refund Received for Years 89-96	(33,298,400)
2008 Estimated Tax Payments	61,075,841
Total	$ (16,522,559)

Schedule Page: 262 Line No.: 17 Column: f

Description	Adjustment Amount	FERC Acct 190	FERC Acct 283	FERC Acct 431
Balance Sheet Reclassifications Due to FIN 48 Liabilities	15,123,481	8,650,135	(23,773,616)	
Interest Expense Reclass Due to FIN 48 Implementation	(10,548,284)			10,548,284
Total	4,575,197	8,650,135	(23,773,616)	10,548,284

Schedule Page: 262 Line No.: 33 Column: a

Note 1:

Ad Valorem taxes are allocated based on the type of assets in each taxing jurisdiction.

Schedule Page: 262 Line No.: 35 Column: a

Note 2:

Sales and Use taxes are allocated based on the Common Allocation Factor.

Schedule Page: 262 Line No.: 37 Column: a

Note 3:

State Franchise Tax and Federal Income Tax are charged to departments based upon total taxable income generated by each department.

Schedule Page: 262 Line No.: 39 Column: a

Note 4:

Retirement, Unemployment and Medicare taxes are charged to departments as a percentage of total taxable labor charged.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		27,776,518			411.4	1,450,000	
7							
8	TOTAL	27,776,518				1,450,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Util - Various	705,991			411.4	675,000	
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
26,326,518	25 to 43 years		6
			7
26,326,518			8
			9
30,991	25 to 30 years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 266 Line No.: 8 Column: f

Transmission related amortization of investment tax credits allocated to current year income is $264,763.

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	CIAC/CAC Tax Gross-Ups	91,464,733	456/495	4,495,479		86,969,254
2	Amortized over various 31 yr lives					
3						
4	Accrued Legal Costs	25,147,891			11,270,774	36,418,665
5						
6	Interconnect Project Advances	16,824,539	242/431	23,273,890	23,884,170	17,434,819
7						
8	SONGS Mitigation	4,394,000			12,912,000	17,306,000
9						
10	Miscellaneous	17,612,431	Various	13,419,237	13,524,439	17,717,633
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	155,443,594		41,188,606	61,591,383	175,846,371

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	5,201,256		
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	5,201,256		
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	5,201,256		
18	Classification of TOTAL			
19	Federal Income Tax	4,522,094		
20	State Income Tax	679,162		
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						5,201,256	4
							5
							6
							7
						5,201,256	8
							9
							10
							11
							12
							13
							14
							15
							16
						5,201,256	17
							18
						4,522,094	19
						679,162	20
							21

NOTES (Continued)

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization

2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	413,741,382	75,491,125	13,287,001
3	Gas	72,475,225	5,923,705	661,497
4				
5	TOTAL (Enter Total of lines 2 thru 4)	486,216,607	81,414,830	13,948,498
6				
7	Non Utility	34,940,753		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	521,157,360	81,414,830	13,948,498
10	Classification of TOTAL			
11	Federal Income Tax	401,311,979	78,629,176	9,872,902
12	State Income Tax	119,845,381	2,785,654	4,075,596
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
				182.3	19,937,599	495,883,105	2
				182.3	1,337,888	79,075,321	3
							4
					21,275,487	574,958,426	5
							6
3,339,526				182.3	11,242,071	49,522,350	7
							8
3,339,526					32,517,558	624,480,776	9
							10
2,615,003					19,067,284	491,750,540	11
724,523					13,450,274	132,730,236	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: b

Transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $91,281,902.

Allocated General and Common accumulated deferred income taxes included in transmission related accumulated deferred income taxes at the beginning of the year was $2,390,472.

Schedule Page: 274 Line No.: 2 Column: k

Transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $102,684,972.

Allocated General and Common accumulated deferred income taxes included in transmission related accumulated deferred income taxes at the end of the year was $2,330,758.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		209,707,017	132,988,837	9,281,572
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	209,707,017	132,988,837	9,281,572
10	Gas			
11		-97,119,250	20,264,872	1,351,327
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-97,119,250	20,264,872	1,351,327
18	Non Utility	11,655,695		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	124,243,462	153,253,709	10,632,899
20	Classification of TOTAL			
21	Federal Income Tax	154,859,068	121,068,356	8,349,763
22	State Income Tax	-30,615,606	32,185,353	2,283,136
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		190	44,362,228	182.3	15,296,594	304,348,648	3
				236	6,197,315	6,197,315	4
							5
							6
							7
							8
			44,362,228		21,493,909	310,545,963	9
							10
		182.3	666,511			-78,872,216	11
		190	6,331,668			-6,331,668	12
							13
							14
							15
							16
			6,998,179			-85,203,884	17
		237	7,786,105	182.3	7,730,611	11,600,201	18
			59,146,512		29,224,520	236,942,280	19
							20
			51,787,365		41,775,846	257,566,142	21
			7,359,147		-12,551,326	-20,623,862	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 9 Column: b

Accumulated deferred income taxes related to electric miscellaneous intangible plant at the beginning of the year is $4,316,753.

Schedule Page: 276 Line No.: 9 Column: k

Accumulated deferred income taxes related to electric miscellaneous intangible plant at the end of the year is $6,584,702.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1						
2	Deferred Taxes Payable in Rates	48,138,206	190	2,080,141		46,058,065
3						
4						
5	Asset Retirement Obligations	549,757,446	230	171,697,318		378,060,128
6						
7						
8	Balancing Account Overcollections	454,927,315	456/495	91,174,696		363,752,619
9						
10						
11	Electric / Gas Derivatives	8,272,601			19,116,691	27,389,292
12						
13						
14	Energy Procurement Discount	4,950,455			253,275	5,203,730
15						
16						
17	TTA Revenue Deferral	2,550,953	456	2,550,953		
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,068,596,976		267,503,108	19,369,966	820,463,834

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	976,249,089	979,643,300
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	843,100,097	852,101,205
5	Large (or Ind.) (See Instr. 4)	215,055,214	228,778,935
6	(444) Public Street and Highway Lighting	11,691,865	12,153,382
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,046,096,265	2,072,676,822
11	(447) Sales for Resale	103,000,457	65,808,889
12	TOTAL Sales of Electricity	2,149,096,722	2,138,485,711
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,149,096,722	2,138,485,711
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	60,176,810	61,586,146
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,669,805	4,991,050
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	347,009,914	-23,798,857
22	(456.1) Revenues from Transmission of Electricity of Others	55,044,211	58,512,742
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	464,900,740	101,291,081
27	TOTAL Electric Operating Revenues	2,613,997,462	2,239,776,792

ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,447,910	4,447,341	1,213,279	1,207,092	2
				3
5,133,601	4,231,135	147,019	145,525	4
1,663,560	1,345,402	515	506	5
75,154	63,343	2,033	2,012	6
				7
				8
				9
12,320,225	10,087,221	1,362,846	1,355,135	10
1,226,665	1,067,862	1	1	11
13,546,890	11,155,083	1,362,847	1,355,136	12
				13
13,546,890	11,155,083	1,362,847	1,355,136	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report End of 2008/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	DR	4,527,390	863,048,620	984,879	4,597	0.1906
2	DRTOU	14,323	3,122,670	1,740	8,232	0.2180
3	EVTOU	84	14,813	10	8,400	0.1763
4	DRLI	739,426	89,134,709	219,561	3,368	0.1205
5	DM	40,618	6,930,361	4,060	10,004	0.1706
6	DS	13,284	1,495,761	243	54,667	0.1126
7	DT	111,280	11,751,447	445	250,067	0.1056
8	OL-1	1,342	540,387	2,297	584	0.4027
9	DWL	163	210,321	44	3,705	1.2903
10	Total Residential Sales (440)	5,447,910	976,249,089	1,213,279	4,490	0.1792
11						
12	A	1,421,775	260,907,486	120,249	11,824	0.1835
13	ATOU	42,060	7,490,719	1,204	34,934	0.1781
14	AD	44,152	8,267,140	311	141,968	0.1872
15	PA	199,302	29,251,789	3,736	53,346	0.1468
16	AL-TOU	3,257,271	505,601,634	18,659	174,568	0.1552
17	AY-TOU	166,121	30,646,864	915	181,553	0.1845
18	OL-1	2,920	934,465	1,945	1,501	0.3200
19	Total Commercial (442)	5,133,601	843,100,097	147,019	34,918	0.1642
20						
21	AL-TOU	1,640,449	211,507,844	506	3,241,994	0.1289
22	A6-TOU	23,111	3,547,370	9	2,567,889	0.1535
23	Total Industrial (442)	1,663,560	215,055,214	515	3,230,214	0.1293
24						
25	LS1	10,488	4,159,865	747	14,040	0.3966
26	LS2	62,674	7,355,259	1,106	56,667	0.1174
27	LS3	1,992	176,741	180	11,067	0.0887
28	Total Public Street and Hwy (444)	75,154	11,691,865	2,033	36,967	0.1556
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,320,225	2,046,096,265	1,362,846	9,040	0.1661
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	12,320,225	2,046,096,265	1,362,846	9,040	0.1661

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	APS Energy Services Inc	SF	10			
2	Barclays Bank PLC	SF	10			
3	Bonneville Power Administration	SF	10			
4	BP Energy Company	SF	10			
5	California ISO Imbalance Energy	SF	10			
6	California Dept of Water Resources	SF	10			
7	Calpine Energy Services	SF	10			
8	Cargill Power Markets LLC	SF	10			
9	Citigroup Energy Inc	SF	10			
10	City of Anaheim	SF	10			
11	City of Riverside	SF	10			
12	City of Roseville	SF	10			
13	City of Vernon	SF	10			
14	ConocoPhillips	SF	10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Constellation Energy Commodities Group	SF	10			
2	Dynegy Power Marketing Inc	SF	10			
3	Fortis Energy Marketing & Trading Group	SF	10			
4	FPL Energy Power Marketing Inc	SF	10			
5	Highland Energy LLC	SF	10			
6	Iberdrola Renewables	SF	10			
7	J Aron & Company	SF	10			
8	J P Morgan Ventures Energy Corporation	SF	10			
9	Lehman Brothers Commodities Services	SF	10			
10	Louis Dreyfus Energy Services LP	SF	10			
11	Macquarie Cook Power Inc	SF	10			
12	Mirant Energy Trading LLC	SF	10			
13	Morgan Stanley Capital Group	SF	10			
14	Northern California Power Agency	SF	10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NRG Power Marketing	SF	10			
2	Occidental Power Services Inc	SF	10			
3	Pacific Gas & Electric Company	SF	10			
4	Pacific Summit Energy LLC	SF	10			
5	PacifiCorp	SF	10			
6	Portland General Electric Company	SF	10			
7	Powerex Corporation	SF	10			
8	Public Service Company of Colorado	SF	10			
9	Puget Sound Energy	SF	10			
10	Reliant Energy Services	SF	10			
11	Sacramento Municipal Utility District	SF	10			
12	Salt River Project	SF	10			
13	Seattle City Light	SF	10			
14	Shell Energy North America (US) LP	SF	10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Silicon Valley Power	SF	10			
2	Southern California Edison Company	SF	10			
3	TransAlta Energy Marketing (US) Inc	SF	10			
4	Turlock Irrigation District	SF	10			
5	UBS Energy	SF	10			
6	Western Area Power Administration	SF	10			
7	Escondido Mutual Water District	SF	076			
8						
9	Less Swap Transactions					
10	Less CA Dept of Water Resources Share					
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	1,367,400			1,367,400	1
48,588		3,195,144		3,195,144	2
5,800		465,400		465,400	3
1,200		54,100		54,100	4
1,063,428		85,534,642		85,534,642	5
38,933		2,302,603		2,302,603	6
14,832		906,340		906,340	7
7,360		551,310		551,310	8
49,760		3,401,524		3,401,524	9
1,648		129,559		129,559	10
1,176		83,687		83,687	11
443		44,395		44,395	12
40		1,740		1,740	13
22,843		1,688,874		1,688,874	14
0	0	0	0	0	
1,226,665	5,139,600	97,860,857	0	103,000,457	
1,226,665	**5,139,600**	**97,860,857**	**0**	**103,000,457**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
16,721	593,400	1,233,983		1,827,383	1
14,766		1,022,826		1,022,826	2
2,920		210,000		210,000	3
4,254		244,650		244,650	4
29		1,450		1,450	5
17,222		1,373,892		1,373,892	6
1,800		144,000		144,000	7
10,045		839,466		839,466	8
25		1,625		1,625	9
2,125		206,215		206,215	10
3,050		208,450		208,450	11
660		65,220		65,220	12
47,297		3,117,150		3,117,150	13
854		53,059		53,059	14
0	0	0	0	0	
1,226,665	5,139,600	97,860,857	0	103,000,457	
1,226,665	**5,139,600**	**97,860,857**	**0**	**103,000,457**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,330		103,320		103,320	1
2,637		163,329		163,329	2
47,893		3,332,856		3,332,856	3
7,160		439,839		439,839	4
26,495		1,700,793		1,700,793	5
28,405		1,804,198		1,804,198	6
17,116		1,272,087		1,272,087	7
400		22,500		22,500	8
1,032		68,086		68,086	9
3,388		239,568		239,568	10
42,536		2,665,229		2,665,229	11
25		950		950	12
2,400		209,400		209,400	13
88,266	3,178,800	6,280,044		9,458,844	14
0	0	0	0	0	
1,226,665	5,139,600	97,860,857	0	103,000,457	
1,226,665	**5,139,600**	**97,860,857**	**0**	**103,000,457**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,245		100,715		100,715	1
10,062		923,153		923,153	2
18,714		1,254,803		1,254,803	3
1,391		131,775		131,775	4
2,106		196,636		196,636	5
2,225		199,170		199,170	6
115		7,810		7,810	7
					8
-234,183		-12,679,818		-12,679,818	9
-221,912		-17,656,890		-17,656,890	10
					11
					12
					13
					14
0	0	0	0	0	
1,226,665	5,139,600	97,860,857	0	103,000,457	
1,226,665	**5,139,600**	**97,860,857**	**0**	**103,000,457**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	933,865	890,785
5	(501) Fuel	207,112,203	161,772,886
6	(502) Steam Expenses	24,201	52,942
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	495	7,509
10	(506) Miscellaneous Steam Power Expenses	2,806,085	4,438,306
11	(507) Rents	241,360	240,392
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	211,118,209	167,402,820
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	15,145	20,423
16	(511) Maintenance of Structures	42,749	2,035
17	(512) Maintenance of Boiler Plant	1,274,458	628,393
18	(513) Maintenance of Electric Plant	467,777	427,536
19	(514) Maintenance of Miscellaneous Steam Plant	1,543,106	1,527,068
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	3,343,235	2,605,455
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	214,461,444	170,008,275
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	21,714,536	19,166,713
25	(518) Fuel	15,559,814	16,570,164
26	(519) Coolants and Water	500,974	313,073
27	(520) Steam Expenses	9,063,813	7,494,242
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,465,156	3,026,159
31	(524) Miscellaneous Nuclear Power Expenses	36,938,762	31,944,450
32	(525) Rents	355,158	416,011
33	TOTAL Operation (Enter Total of lines 24 thru 32)	86,598,213	78,930,812
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,503,832	20,655,329
36	(529) Maintenance of Structures	3,995,729	4,138,105
37	(530) Maintenance of Reactor Plant Equipment	11,659,593	6,974,343
38	(531) Maintenance of Electric Plant	5,306,235	4,512,561
39	(532) Maintenance of Miscellaneous Nuclear Plant	11,071,953	3,553,838
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	35,537,342	39,834,176
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	122,135,555	118,764,988
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	319,156	364,304
63	(547) Fuel	2,059,440	678,880
64	(548) Generation Expenses	-286,429	469,622
65	(549) Miscellaneous Other Power Generation Expenses	2,694,680	4,130,118
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	4,786,847	5,642,924
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	761	3,244
70	(552) Maintenance of Structures	35,467	35,535
71	(553) Maintenance of Generating and Electric Plant	9,105,145	9,172,055
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,829,996	2,622,785
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	12,971,369	11,833,619
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	17,758,216	17,476,543
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	733,321,594	508,811,924
77	(556) System Control and Load Dispatching	2,170,954	1,912,700
78	(557) Other Expenses	5,155,752	4,023,147
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	740,648,300	514,747,771
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,095,003,515	820,997,577
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,007,422	4,935,230
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	455,825	400,361
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,958,385	2,301,487
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,780,058	9,016,976
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,371,452	1,507,750
93	(562) Station Expenses	2,084,087	2,061,862
94	(563) Overhead Lines Expenses	778,707	1,044,508
95	(564) Underground Lines Expenses	-109	3,213
96	(565) Transmission of Electricity by Others	5,146,751	7,655,358
97	(566) Miscellaneous Transmission Expenses	65,846,993	71,778,918
98	(567) Rents	1,579,539	1,415,236
99	TOTAL Operation (Enter Total of lines 83 thru 98)	93,009,110	102,120,899
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	967,416	935,616
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	1,168,531	1,058,121
104	(569.2) Maintenance of Computer Software	1,928,215	1,181,560
105	(569.3) Maintenance of Communication Equipment		1,299
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,430,447	6,792,585
108	(571) Maintenance of Overhead Lines	9,637,229	11,986,408
109	(572) Maintenance of Underground Lines	22,051	63,000
110	(573) Maintenance of Miscellaneous Transmission Plant	75,786	70,471
111	TOTAL Maintenance (Total of lines 101 thru 110)	19,229,675	22,089,060
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	112,238,785	124,209,959

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	3,844,078	2,072,956
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,844,078	2,072,956
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	3,844,078	2,072,956
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	12,063,925	12,312,631
135	(581) Load Dispatching	2,965,109	3,231,587
136	(582) Station Expenses	7,181,755	4,658,369
137	(583) Overhead Line Expenses	2,582,086	2,160,829
138	(584) Underground Line Expenses	3,128,869	3,131,146
139	(585) Street Lighting and Signal System Expenses	565,180	638,520
140	(586) Meter Expenses	10,729,608	11,896,536
141	(587) Customer Installations Expenses	5,201,686	5,522,397
142	(588) Miscellaneous Expenses	22,033,449	23,569,230
143	(589) Rents	97,234	99,963
144	TOTAL Operation (Enter Total of lines 134 thru 143)	66,548,901	67,221,208
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,174,776	1,569,777
147	(591) Maintenance of Structures	74,183	57,009
148	(592) Maintenance of Station Equipment	3,529,408	4,853,822
149	(593) Maintenance of Overhead Lines	39,520,293	36,012,338
150	(594) Maintenance of Underground Lines	7,667,221	8,507,206
151	(595) Maintenance of Line Transformers	126,211	299,410
152	(596) Maintenance of Street Lighting and Signal Systems	92,026	60,312
153	(597) Maintenance of Meters	567,721	779,580
154	(598) Maintenance of Miscellaneous Distribution Plant	120,121	32,645
155	TOTAL Maintenance (Total of lines 146 thru 154)	52,871,960	52,172,099
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	119,420,861	119,393,307
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	79,632	89,260
160	(902) Meter Reading Expenses	11,140,694	10,701,446
161	(903) Customer Records and Collection Expenses	37,924,658	40,418,290
162	(904) Uncollectible Accounts	4,590,120	3,189,787
163	(905) Miscellaneous Customer Accounts Expenses	3,036	119,351
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	53,738,140	54,518,134

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	146,294	138,999
168	(908) Customer Assistance Expenses	158,518,898	118,599,694
169	(909) Informational and Instructional Expenses	68,451	33,080
170	(910) Miscellaneous Customer Service and Informational Expenses	1,633,357	1,778,329
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	160,367,000	120,550,102
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		93,574
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		93,574
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	19,023,672	12,649,660
182	(921) Office Supplies and Expenses	7,949,929	6,311,243
183	(Less) (922) Administrative Expenses Transferred-Credit	4,012,010	3,664,221
184	(923) Outside Services Employed	53,473,972	56,757,237
185	(924) Property Insurance	3,021,835	1,958,412
186	(925) Injuries and Damages	13,267,996	11,980,092
187	(926) Employee Pensions and Benefits	45,418,173	35,415,492
188	(927) Franchise Requirements	73,939,354	75,420,554
189	(928) Regulatory Commission Expenses	13,617,576	9,897,846
190	(929) (Less) Duplicate Charges-Cr.	1,829,866	1,617,934
191	(930.1) General Advertising Expenses	17,842	6,865
192	(930.2) Miscellaneous General Expenses	8,012,464	20,393,508
193	(931) Rents	9,560,844	7,337,014
194	TOTAL Operation (Enter Total of lines 181 thru 193)	241,461,781	232,845,768
195	Maintenance		
196	(935) Maintenance of General Plant	6,798,293	6,316,581
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	248,260,074	239,162,349
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,792,872,453	1,480,997,958

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of San Diego (Pt. Loma Renewable)	LF	001			
2	Covanta Delano Inc (Renewable)	LF	001			
3	Covanta Otay 3 (Renewable)	LF	001			
4	CP Kelco US Inc	LF	001			
5	EnerNoc Inc	LF	001			
6	Fortistar Renewables Gp LLC Miramar	LF	001			
7	Fortistar Renewables GP LLC North City	LF	001			
8	FortistarRenewablesGPLLCPrimaDeshecha	LF	001			
9	FPL Energy Green Power Wind LLC	LF	001			
10	Gas Recovery Systems Coyote Canyon	LF	001			
11	Gas Recovery Systems Sycamore Canyon	LF	001			
12	Iberdrola Renewables	LF	001			
13	Kumeyaay Wind LLC	LF	001			
14	Oasis Power Partners LLC	LF	001			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Portland General Electric Company	LF	001			
2	San Diego County Water Authority	LF	001			
3	Yuma Co-generator Association	LF	001			
4	Dynegy Power Mktg Inc (Tolling)	IF				
5	NRG Power Mktg Inc (Tolling)	IF				
6	California ISO/PX					
7	California ISO Imbalance Energy					
8	Brokerage Fees					
9	Co-generation					
10	Barclays Bank PLC	SF	001			
11	Bonneville Power Administration	SF	001			
12	BP Energy Company	SF	001			
13	California Dept of Water Resources	SF	001			
14	Calpine Energy Services	SF	001			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Cargill Power Markets LLC	SF	001			
2	Citigroup Energy Inc	SF	001			
3	City of Anaheim	SF	001			
4	City of Riverside	SF	001			
5	City of Roseville	SF	001			
6	Conoco Phillips	SF	001			
7	Constellation Energy CommoditiesGP Inc	SF	001			
8	Dynegy Power Marketing Inc	SF	001			
9	EPCOR Energy Marketing (US) Inc	SF	001			
10	Fortis Energy Mktg & Trading Group	SF	001			
11	FPL Energy Power Marketing Inc	SF	001			
12	Highland Energy LLC	SF	001			
13	Iberdrola Renewables	SF	001			
14	J Aron & Company	SF	001			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	J P Morgan Ventures Energy Corporation	SF	001			
2	Lehman Brothers Commodities Services	SF	001			
3	Louis Dreyfus Energy Services LP	SF	001			
4	Macquarie Cook Power Inc	SF	001			
5	Mirant Energy Trading LLC	SF	001			
6	Modesto Irrigation District	SF	001			
7	Morgan Stanley Capital Group	SF	001			
8	Northern California Power Agency	SF	001			
9	NRG Power Marketing	SF	001			
10	Occidental Power Services Inc	SF	001			
11	Pacific Gas & Electric Company	SF	001			
12	Pacific Summit Energy LLC	SF	001			
13	PacifiCorp	SF	001			
14	Portland General Electric Company	SF	001			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Powerex Corporation	SF	001			
2	Public Service Company of Colorado	SF	001			
3	Public Service Company of New Mexico	SF	001			
4	Puget Sound Energy	SF	001			
5	Reliant Energy Services	SF	001			
6	Sacramento Municipal Utility District	SF	001			
7	Salt River Project	SF	001			
8	Seattle City Light	SF	001			
9	Shell Energy North America (US) LP	SF	001			
10	Sierra Pacific Power Company	SF	001			
11	Snohomish County PUD	SF	001			
12	Southern California Edison Company	SF	001			
13	Tacoma Power	SF	001			
14	TransAlta Energy Marketing (US) Inc	SF	001			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Turlock Irrigation District	SF	001			
2	UBS Energy	SF	001			
3	Western Area Power Administration	SF	001			
4						
5	Less Swap Transactions					
6	Derivatives Gains & Losses					
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
12,876				973,446		973,446	1
317,204				22,995,311		22,995,311	2
24,465				1,377,866		1,377,866	3
27,275			809,285	1,537,151		2,346,436	4
			1,909,604			1,909,604	5
28,526				1,480,437		1,480,437	6
3,542				183,518		183,518	7
38,215				1,849,303		1,849,303	8
24,555				1,294,076		1,294,076	9
53,591				2,877,815		2,877,815	10
12,033				646,151		646,151	11
72,787				3,580,944		3,580,944	12
150,598				7,605,199		7,605,199	13
196,161				9,651,121		9,651,121	14
7,869,273	27,205	27,205	168,738,256	556,630,813	7,952,525	733,321,594	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
605,068			36,700,296	8,457,889		45,158,185	1
22,894				1,210,445		1,210,445	2
370,236			8,394,656	32,936,561		41,331,217	3
474,909			37,893,288	18,047,390		55,940,678	4
1,005,765			52,842,249	91,055,788		143,898,037	5
			308,446	11,337,014		11,645,460	6
134,297				8,482,726		8,482,726	7
					265,124	265,124	8
1,085,966			29,825,432	103,471,858		133,297,290	9
146,085	800	800		9,699,641		9,699,641	10
2,551				133,332		133,332	11
11,974				696,004		696,004	12
191,644	2,275	2,275		16,390,195		16,390,195	13
127,936	13,565	13,565		9,101,652		9,101,652	14
7,869,273	27,205	27,205	168,738,256	556,630,813	7,952,525	733,321,594	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
218,424				12,708,758		12,708,758	1
212,555				14,716,329		14,716,329	2
31,709				1,631,759		1,631,759	3
150				7,475		7,475	4
715				51,714		51,714	5
434,475				31,192,603		31,192,603	6
48,618				3,695,909		3,695,909	7
92,574	4,100	4,100		6,367,427		6,367,427	8
400				45,400		45,400	9
99,675				6,172,077		6,172,077	10
91,578	1,400	1,400		7,175,791		7,175,791	11
665				25,985		25,985	12
43,613				3,007,691		3,007,691	13
19,250				1,070,550		1,070,550	14
7,869,273	27,205	27,205	168,738,256	556,630,813	7,952,525	733,321,594	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
52,616				3,849,674		3,849,674	1
625				53,750		53,750	2
9,170				675,350		675,350	3
20,880				1,587,151		1,587,151	4
33,462				2,374,066		2,374,066	5
20				1,620		1,620	6
185,114	40	40		12,522,809		12,522,809	7
3,752				341,453		341,453	8
12,737	200	200		1,097,354		1,097,354	9
35,952				2,977,812		2,977,812	10
59,570				4,585,812		4,585,812	11
88,650	1,325	1,325		5,271,963		5,271,963	12
35,417				2,487,761		2,487,761	13
8,560				653,574		653,574	14
7,869,273	27,205	27,205	168,738,256	556,630,813	7,952,525	733,321,594	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
265,607				20,158,253		20,158,253	1
4,000				320,920		320,920	2
200				6,700		6,700	3
30,998				818,732		818,732	4
23,530	925	925	55,000	1,737,115		1,792,115	5
32,632	75	75		2,646,925		2,646,925	6
20,800				1,186,436		1,186,436	7
25,140				725,840		725,840	8
320,586	2,300	2,300		20,707,626		20,707,626	9
3,672				183,709		183,709	10
200				400		400	11
219,543				12,594,295		12,594,295	12
400				200		200	13
134,516	200	200		11,607,540		11,607,540	14
7,869,273	27,205	27,205	168,738,256	556,630,813	7,952,525	733,321,594	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,907				236,384		236,384	1
27,411				2,242,080		2,242,080	2
9,235				715,027		715,027	3
							4
-234,183				-12,679,819		-12,679,819	5
					7,687,401	7,687,401	6
							7
							8
							9
							10
							11
							12
							13
							14
7,869,273	27,205	27,205	168,738,256	556,630,813	7,952,525	733,321,594	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Los Angeles Department of Water and Power	N/A	N/A	OS
2	California ISO	N/A	N/A	OS
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
001	N/A	N/A				1
001	N/A	N/A				2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**0**	**0**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	21,232		21,232	1
	55,022,979		55,022,979	2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	**55,044,211**	**0**	**55,044,211**	

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	COI Path Operator	OS			3,889			3,889
2	PacifiCorp	OS			2,771			2,771
3	Portland General Elec	FNS			5,140,091			5,140,091
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				5,146,751			5,146,751

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 3 Column: a

Amount reported includes firm Boardman transmission demand, ancillary services and firm wheeling reservation charges.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	6,100,000
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	California Energy Commission Renewable Payments	6,400,000
7	Securities Expenses, Bank Service and Commitment Fee	255,252
8	Abandoned Projects	-743,429
9	Expense Reclass	-1,314,091
10	Account Receivable Adjustment	-3,645,075
11	Miscellaneous Expenses	959,807
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	8,012,464

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,723,459		2,723,459
2	Steam Production Plant	10,040,485				10,040,485
3	Nuclear Production Plant	14,432,673				14,432,673
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	7,434,266				7,434,266
7	Transmission Plant	34,881,694			621,145	35,502,839
8	Distribution Plant	150,017,244			1,424,000	151,441,244
9	Regional Transmission and Market Operation					
10	General Plant	6,996,298				6,996,298
11	Common Plant-Electric	18,595,336		9,748,247		28,343,583
12	TOTAL	242,397,996		12,471,706	2,045,145	256,914,847

B. Basis for Amortization Charges

Account 404
Amortization of intangible plant (software) is based on a five year recovery period of each software project with the exception of projects over a dollar threshold of $10,000,000 which have a fifteen year recovery period.

Account 405
The amortization of Land Rights is based on the anticipated useful lives of the rights-of-way.

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report End of 2008/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13	311	34,533	30.00	-11.00	3.69	Forecast	28.50
14	312	105,233	30.00	-8.00	3.58	Forecast	28.50
15	314	91,582	30.00	-7.00	3.55	Forecast	28.50
16	315	31,205	30.00	-6.00	3.51	Forecast	28.50
17	316	18,748	30.00	-5.00	3.48	Forecast	28.50
18	SUBTOTAL	281,301					
19							
20	NUCLEAR PRODUCTION						
21	321	3,887	17.00		6.14	Forecast	14.50
22	322						
23	323	2,822	17.00		6.73	Forecast	14.50
24	324	227	17.00		6.25	Forecast	14.50
25	325	61,995	17.00		5.41	Forecast	14.50
26	SUBTOTAL	68,931					
27							
28	OTHER PRODUCTION						
29	341	4,456	25.00	-3.00	3.72	Forecast	25.60
30	342	15,296	25.00	-4.00	3.50	Forecast	28.00
31	343	20,824	25.00	-1.00	4.05	Forecast	22.50
32	344	165,716	25.00		3.33	Forecast	28.30
33	345	9,496	25.00	-1.00	3.76	Forecast	24.70
34	346	359	25.00	2.00	3.92	Forecast	22.50
35	SUBTOTAL	216,147					
36							
37	TRANSMISSION-SWPL						
38	352	9,980					
39	353	160,670					
40	354	61,988					
41	355	8,106					
42	356	42,154					
43	359	4,427					
44	SUBTOTAL	287,325					
45							
46	TRANSMISSION-OTHER						
47	352	72,971					
48	353	371,816					
49	354	43,599					
50	355	123,730					

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	356	176,909					
13	357	115,852					
14	358	95,426					
15	359	17,711					
16	SUBTOTAL	1,018,014					
17							
18	DISTRIBUTION						
19	361	3,274	49.00	-20.00	1.83	Iowa 49 R2.5	35.10
20	362	309,062	43.00	-15.00	2.79	Iowa 43 R2	33.10
21	364	403,203	43.00	-100.00	4.37	Iowa 43 R0.5	35.10
22	365	316,148	43.00	-100.00	4.97	Iowa 43 R1	33.70
23	366	790,170	52.00	-40.00	2.58	Iowa 52 R3	39.30
24	367	1,062,295	37.00	-65.00	4.21	Iowa 37 R3	26.50
25	368.1	395,119	31.00	-30.00	4.68	Iowa 31 L0.5	24.30
26	368.2	19,610	13.00	-40.00	16.44	Iowa 13 L0	8.50
27	369.1	100,184	41.00	-125.00	3.27	Iowa 41 R0.5	31.80
28	369.2	270,660	41.00	-95.00	4.83	Iowa 41 R4	28.00
29	370.1	89,160	36.00		2.35	Iowa 36 SC	27.30
30	370.2	42,894	36.00	-15.00	3.23	Iowa 36 SC	28.30
31	371	6,158	17.00	-120.00	9.28	Iowa 17 R0.5	7.40
32	373.2	23,109	26.00	-30.00	3.25	Iowa 26 L0	17.90
33	SUBTOTAL	3,831,046					
34							
35	GENERAL						
36	390	29,482	30.00	-15.00	5.14	Forecast	14.80
37	392.2	176	27.00		7.17	Iowa 27 SQ	3.40
38	393	54	25.00		3.15	Iowa 25 SQ	4.10
39	394.1	13,287	27.00		3.82	Iowa 27 SQ	18.00
40	394.2	464	24.00	-5.00	5.61	Iowa 24 SQ	8.10
41	395	296	20.00		7.70	Iowa 20 SQ	14.70
42	397.1	98,504	22.00	-10.00	4.70	Iowa 22 R2.5	14.10
43	397.2	5,731	22.00	-10.00	4.20	Iowa 22 R2.5	9.50
44	398	461	15.00		8.96	Iowa 15 SQ	12.10
45	SUBTOTAL	148,455					
46							
47	TOTAL	5,851,219					
48							
49							
50	SEE FOOTNOTE						

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 3 Column: b

Nuclear Production Plant includes $9,350,000 of nuclear decommissioning expense.

Schedule Page: 336 Line No.: 12 Column: f

Reclassification of 2008 Electric Depreciation and Amortization Charges
Depreciation and Amortization Expense Charged in Accordance with FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	Depreciation Expense (Account 403)	Amortization of Limited Term Electric Plant (Account 404)	Amortization of Other Electric Plant (Account 405)	Total
Intangible Plant	-	2,723,459	-	2,723,459
Steam Production	10,311,097	-	-	10,311,097
Nuclear Production	14,432,673	-	-	14,432,673
Other Production	7,470,906	-	-	7,470,906
Transmission Plant	33,942,084	-	614,795	34,556,879
Distribution Plant	150,649,602	-	1,430,350	152,079,952
General Plant	6,996,298	-	-	6,996,298
Common Plant-Electric	18,595,336	9,748,247	-	28,343,583
Total Ratemaking Depreciation & Amort.	242,397,996*	12,471,706*	2,045,145*	256,914,847*

*Line 12 of FERC Form 1, page 336.

Schedule Page: 336.1 Line No.: 50 Column: a

Items in column (b) are 12/31/08 weighted plant balances based on 12/31/2007 plant balances (Account 101) plus weighted net additions for 2008 less non-depreciables for each plant account.

Lines 37-50, Page 337 and Lines 12-16, Page 337.1 (Transmission-SWPL and Transmission-Other), Cols. C-G: No change.

All other lines, Cols. C-G: The applied depreciation rates, estimated average service lives, remaining lives and net salvage percentages were approved for Test Year 2008 by the California Public Utilities Commission in Decision 08-07-046.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	California Public Utilities Commission	4,761,761		4,761,761	
2	Reimbursement Fees	724,223		724,223	
3					
4	FERC Proceedings		22,836	22,836	
5			52,554	52,554	
6					
7	Intervenor Compensation		686,099	686,099	
8			60,281	60,281	
9					
10	Litigation Cost Memo Account Expenses		157,050	157,050	
11					
12	CPUC R.03-12-062		89,942	89,942	
13	Energy Procurement Audit				
14					
15	CPUC A.06-12-009		277,817	277,817	
16	General Rate Case (2008)		230,012	230,012	
17					
18	Miscellaneous Items Less Than $25,000		14,139	14,139	
19	Various Cases		58,162	58,162	
20					
21	General Internal Labor & Expenses		7,607,933	7,607,933	
22			2,185,777	2,185,777	
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,485,984	11,442,602	16,928,586	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Electric	928	4,761,761					1
Gas	928	724,223					2
							3
Electric	928	22,836					4
Gas	928	52,554					5
							6
Electric	928	686,099					7
Gas	928	60,281					8
							9
Electric	928	157,050					10
							11
Electric	928	89,942					12
							13
							14
Electric	928	277,817					15
Gas	928	230,012					16
							17
Electric	928	14,139					18
Gas	928	58,162					19
							20
Electric	928	7,607,933					21
Gas	928	2,185,777					22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		16,928,586					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:
A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $5,000.)
(7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed Internally	
2		
3	(1) Generation	NONE
4		
5	(2) System Planning, Engineering and Operation	NONE
6		
7	(3) Transmission	NONE
8		
9	(4) Distribution	NONE
10		
11	(5) Environment	NONE
12		
13	(6) Other	NONE
14		
15	(7) Sub Total Internal Costs Incurred	
16		
17	B. External	
18		
19	(1) Research Support to the Electrical	NONE
20	Research Council or the Electric Power	
21	Research Institute	
22		
23	(2) Research Support to Edison Electric Inst.	NONE
24		
25	(3) Research Support to Nuclear Power Groups	NONE
26		
27	(4) Research Support to Others	Public Interest Energy, California Energy Commission,
28		
29	(5) Sub Total External Costs Incurred	
30		
31		
32		
33		
34		Grand Total
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
	6,100,000	930.20	6,100,000		27
					28
	6,100,000		6,100,000		29
					30
					31
					32
					33
	6,100,000		6,100,000		34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	6,318,517		
4	Transmission	9,176,660		
5	Regional Market			
6	Distribution	36,516,512		
7	Customer Accounts	23,700,390		
8	Customer Service and Informational	12,377,588		
9	Sales			
10	Administrative and General	17,525,131		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	105,614,798		
12	Maintenance			
13	Production	680,234		
14	Transmission	6,576,673		
15	Regional Market			
16	Distribution	14,197,987		
17	Administrative and General	1,828,155		
18	TOTAL Maintenance (Total of lines 13 thru 17)	23,283,049		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	6,998,751		
21	Transmission (Enter Total of lines 4 and 14)	15,753,333		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	50,714,499		
24	Customer Accounts (Transcribe from line 7)	23,700,390		
25	Customer Service and Informational (Transcribe from line 8)	12,377,588		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	19,353,286		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	128,897,847	40,678,403	169,576,250
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	251,931		
34	Storage, LNG Terminaling and Processing	55,860		
35	Transmission	2,289,146		
36	Distribution	17,239,107		
37	Customer Accounts	12,415,599		
38	Customer Service and Informational	1,621,087		
39	Sales			
40	Administrative and General	4,995,012		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	38,867,742		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	2,881,820		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	2,827,969		
49	Administrative and General	504,075		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	6,213,864		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	251,931		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	55,860		
56	Transmission (Lines 35 and 47)	5,170,966		
57	Distribution (Lines 36 and 48)	20,067,076		
58	Customer Accounts (Line 37)	12,415,599		
59	Customer Service and Informational (Line 38)	1,621,087		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	5,499,087		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	45,081,606	13,793,896	58,875,502
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	173,979,453	54,472,299	228,451,752
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	44,327,760	78,567,433	122,895,193
69	Gas Plant	5,890,812	8,480,443	14,371,255
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	50,218,572	87,047,876	137,266,448
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,065,719	8,802,325	14,868,044
74	Gas Plant	344,761	577,695	922,456
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	6,410,480	9,380,020	15,790,500
77	Other Accounts (Specify, provide details in footnote):			
78	3rd Party Billings,Gas		1,318,691	1,318,691
79	3rd Party Billings, Electric		5,865,877	5,865,877
80	Affiliate Billing, Gas		16,093,787	16,093,787
81	Affiliate Billing, Electric		58,390,347	58,390,347
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts		81,668,702	81,668,702
96	TOTAL SALARIES AND WAGES	230,608,505	232,568,897	463,177,402

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account	Balance Beg. of Year	Additions	Retire From Serv.	Adjs.	Transfers	Balance End of Year
303 Misc. Intangible Plant	172,285,048	15,518,231				187,803,279
389 Land & Land Rights	7,051,999	(12,251)				7,039,748
390 Structures & Improvements	140,127,168	18,011,305	458,514		(645,961)	157,033,998
391 Office Furniture & Equipment	66,145,665	4,383,469	22,020,193		641,528	49,150,469
392 Transportation Equipment	67,312					67,312
393 Stores Equipment	140,123					140,123
394 Tools, Shop & Garage Equip.	3,133,462	20,936	234,925			2,919,473
395 Laboratory Equipment	2,460,188	44,490	41,380			2,463,298
396 Power Operated Equipment						
397 Communication Equipment	72,563,444	16,571,806	3,182,658		4,434	85,957,026
398 Miscellaneous Equipment	2,924,131		920,589			2,003,542
FIN 47 ARC - Common	780,452					780,452
TOTAL COMMON PLANT	467,678,992	54,537,986	26,858,259		1	495,358,720
Construction Work in Progress	68,738,035	67,105,231				135,843,266
TOTAL COMMON PLANT	536,417,027	121,643,217	26,858,259		1	631,201,986

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

ACCOUNT	December 31, 2008 Accumulated Depreciation
303 Misc. Intangible Plant	157,014,151
389 Land & Land Rights	27,275
390 Structures & Improvements	60,860,200
391 Office Furniture & Equipment	27,911,683
392 Transportation Equipment	(408,875)
393 Stores Equipment	(105,459)
394 Tools, Shop & Garage Equipment	970,657
395 Laboratory Equipment	887,916
396 Power Operated Equipment	(192,979)
397 Communication Equipment	46,408,940
398 Miscellaneous Equipment	206,592
108.4 Retirement Work in Progress	
FIN 47 Accumulated Depreciation	421,991
Total Accumulated Depreciation	294,002,092

Split of Common Utility Plant to Departments: (excluding CWIP) (see Note 2- Page 356.2)

		December 31,2008 Balance End of Year	Accumulated Depreciation
Electric	78.393%	388,311,701	230,468,240
Gas	21.607%	107,047,019	63,533,852
Total	100.000%	495,358,720	294,002,092

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

ACCOUNT		Ad Valorem Taxes Note (1)	Depreciation Note (2)
303	Misc. Intangible Plant		12,435,574
389	Land & Land Rights		
390	Structures & Improvements		7,914,404
391	Office Furniture & Equipment		9,817,101
392	Transportation Equipment		19,134
393	Stores Equipment		62,971
394	Tools, Shop & Garage Equipment		347,542
395	Laboratory Equipment		106,241
396	Power Operated Equipment		
397	Communication Equipment		5,262,016
398	Miscellaneous Equipment		192,157
	Total	3,006,858	36,157,140

(1) Ad Valorem Taxes on property are assessed by the State Board of Equalization and consist of one-half of the taxes from each fiscal tax year 2007-2008 and 2008-2009. Ad Valorem Taxes are assessed on the entire operating unit, therefore, assessed taxes are not available by account number. Ad Valorem Taxes are allocated based on procedures adopted by the California Public Utilities Commission.

(2) The Common Utility Plant and Accumulated Depreciation is allocated between the Electric and Gas Departments based on use factors developed in accordance with allocation procedures proposed by the California Public Utilities Commission. These rates were revised in January 2008.
Other expenses of operation, maintenance and rents for common utility plant are allocated based on labor percentage studies. Specific amounts charged to operations and maintenance are not readily available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	2,199,736	8,209,515	7,740,176	8,482,726
3	Net Sales (Account 447)	(15,805,396)	(32,180,138)	(57,305,759)	(85,534,642)
4	Transmission Rights	308,445	308,445	308,445	308,445
5	Ancillary Services	146,472	1,203,781	4,172,703	4,061,873
6	Other Items (list separately)				
7	Congestion	1,042,474	1,393,169	2,989,327	3,754,544
8	MLCC (minimumload carrying cost)	(1,341,927)	(4,417,756)	(7,957,701)	(10,624,779)
9	Other	4,428,386	7,329,411	16,113,420	21,532,542
10	UFE (unaccounted for energy)	(8,292,685)	(10,091,305)	(11,730,909)	(7,831,717)
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(17,314,495)	(28,244,878)	(45,670,298)	(65,851,008)

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	467,342	Mw	9,506,815	738,636	Mw	5,233,769
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	467,342		9,506,815	738,636		5,233,769

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2009	Year/Period of Report End of 2008/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	3,223	24	1800	3,223					
2	February	3,273	14	1800	3,273					
3	March	3,014	3	1900	3,014					
4	Total for Quarter 1	9,510			9,510					
5	April	3,604	28	1500	3,604					
6	May	3,873	19	1500	3,873					
7	June	4,172	20	1500	4,172					
8	Total for Quarter 2	11,649			11,649					
9	July	3,721	15	1500	3,721					
10	August	4,011	7	1500	4,011					
11	September	4,097	30	1500	4,097					
12	Total for Quarter 3	11,829			11,829					
13	October	4,351	1	1400	4,351					
14	November	3,296	17	1800	3,296					
15	December	3,514	17	1800	3,514					
16	Total for Quarter 4	11,161			11,161					
17	Total Year to Date/Year	44,149			44,149					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	3,589,590
4	Nuclear	3,078,365
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	22,787
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	6,690,742
10	Purchases	7,869,273
11	Power Exchanges:	
12	Received	27,205
13	Delivered	27,205
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	
17	Delivered	
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	14,560,015

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	12,320,225
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,226,665
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	27,751
27	Total Energy Losses	985,374
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	14,560,015

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,207,162	111,371	3,223	24	1800
30	February	1,043,662	107,124	3,273	14	1800
31	March	994,119	81,959	3,014	3	1900
32	April	1,058,974	48,666	3,604	28	1500
33	May	1,082,667	39,129	3,873	19	1500
34	June	1,230,921	146,587	4,172	20	1500
35	July	1,254,110	81,081	3,721	15	1500
36	August	1,418,063	99,126	4,011	7	1500
37	September	1,345,992	92,998	4,097	30	1500
38	October	1,465,971	139,161	4,351	1	1400
39	November	1,212,626	159,419	3,296	17	1800
40	December	1,245,748	120,044	3,514	17	1800
41	TOTAL	14,560,015	1,226,665			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *San Onofre* (b)			Plant Name: *Miramar Energy Fac* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor			Semi-Outdoor		
3	Year Originally Constructed	1967			2005		
4	Year Last Unit was Installed	1984			2005		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	451.00			49.70		
6	Net Peak Demand on Plant - MW (60 minutes)	430			48		
7	Plant Hours Connected to Load	8760			516		
8	Net Continuous Plant Capability (Megawatts)	0			50		
9	When Not Limited by Condenser Water	430			0		
10	When Limited by Condenser Water	430			0		
11	Average Number of Employees	2			1		
12	Net Generation, Exclusive of Plant Use - KWh	3078365000			22787000		
13	Cost of Plant: Land and Land Rights	283677			0		
14	Structures and Improvements	272255875			2460008		
15	Equipment Costs	967932763			31723892		
16	Asset Retirement Costs	126553134			0		
17	Total Cost	1367025449			34183900		
18	Cost per KW of Installed Capacity (line 17/5) Including	3031.0986			687.8048		
19	Production Expenses: Oper, Supv, & Engr	21714536			14178		
20	Fuel	15559814			1840401		
21	Coolants and Water (Nuclear Plants Only)	500974			0		
22	Steam Expenses	9063813			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2465156			183415		
26	Misc Steam (or Nuclear) Power Expenses	36938762			0		
27	Rents	355158			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	3503832			0		
30	Maintenance of Structures	3995729			0		
31	Maintenance of Boiler (or reactor) Plant	11659593			0		
32	Maintenance of Electric Plant	5306235			235148		
33	Maintenance of Misc Steam (or Nuclear) Plant	11071953			0		
34	Total Production Expenses	122135555			2273142		
35	Expenses per Net KWh	0.0397			0.0998		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				MCF		
38	Quantity (Units) of Fuel Burned	32495642	0	0	220612	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1020	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.505	0.000	0.000	8.340	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.505	0.000	0.000	8.160	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.005	0.000	0.000	0.082	0.000	0.000
44	Average BTU per KWh Net Generation	10556.137	0.000	0.000	9897.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Palomar Energy Centr* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combined Cycle			1
Semi-Outdoor			2
2006			3
2006			4
636.00	0.00	0.00	5
566	0	0	6
8304	0	0	7
565	0	0	8
565	0	0	9
0	0	0	10
30	0	0	11
3589590000	0	0	12
14480000	0	0	13
37178272	0	0	14
438859774	0	0	15
0	0	0	16
490518046	0	0	17
771.2548	0.0000	0.0000	18
701549	0	0	19
207112024	0	0	20
0	0	0	21
2257583	0	0	22
0	0	0	23
0	0	0	24
2874099	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
13498	0	0	29
68111	0	0	30
1298017	0	0	31
12944915	0	0	32
1396933	0	0	33
228666729	0	0	34
0.0637	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas									36
MCF									37
24490902	0	0	0	0	0	0	0	0	38
1020	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
8.450	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
8.270	0.000	0.000	0.000	0.000	0.000	0.000	0.000	505.000	42
0.058	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
6975.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 402   Line No.: -1   Column: b

San Diego Gas & Electric Company's share of San Onofre is 20%. Southern California Edison owns 75.05% and the Cities of Anaheim and Riverside own 4.95% of San Onofre.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Miguel	Imperial Valley	500.00	500.00	3	83.50		1
2	Imperial Valley		500.00	500.00	3	51.50		1
3		North Gila	500.00	500.00	1S	24.00		1
4	North Gila	Palo Verde	500.00	500.00	3	120.00		1
5	TOTAL 500KV LENGTH					279.00		4
6								
7	San Luis Rey Tap		230.00	230.00	3		5.29	2
8			230.00	230.00	3	26.45		2
9		Mission	230.00	230.00	2W	3.26		1
10	San Luis Rey		230.00	230.00	3	0.11		1
11			230.00	230.00	2S	0.49		2
12			230.00	230.00	2W	1.00		1
13		San Onofre	230.00	230.00	3	16.26		2
14	San Luis Rey		230.00	230.00	3	5.75		1
15		Encina	230.00	230.00	3	1.47		1
16	San Luis Rey		230.00	230.00	2W	2.34		1
17			230.00	230.00	3		26.58	2
18		Mission	230.00	230.00	2W		3.26	1
19	San Luis Rey	San Onofre	230.00	230.00	3	18.12		2
20	San Onofre		230.00	230.00	2S	0.47		2
21			230.00	230.00	3	6.00		2
22		Talega	230.00	230.00	3	0.43		1
23	San Onofre		230.00	230.00	3		16.82	2
24			230.00	230.00	2W	0.78		1
25			230.00	230.00	1S	0.63		2
26		Encina	230.00	230.00	3		1.90	2
27	Encina	Encina Hub	230.00	230.00	1S		1.44	2
28	Encina Hub	San Luis Rey	230.00	230.00	3		5.87	2
29	Encina Hub		230.00	230.00	1S,3		0.73	2
30			230.00	230.00	1S		0.06	2
31			230.00	230.00	3		0.90	2
32			230.00	230.00	3		5.96	2
33		Palomar	230.00	230.00	1S		0.80	2
34	Encina		230.00	230.00	1S		1.44	2
35			230.00	230.00	3		1.00	1
36					TOTAL	1,522.55	389.85	390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1			230.00	230.00	3		3.43	2
2			230.00	230.00	1S		10.34	2
3			230.00	230.00	1S		2.00	2
4		Penasquitos	230.00	230.00	1S	0.10		1
5	Penasquitos		230.00	230.00	1S	11.05		1
6		Old Town	230.00	230.00	1S	0.47		1
7	Palomar		230.00	230.00	1S		0.16	1
8		Escondido	230.00	230.00	1S		0.22	1
9	Palomar Generator		230.00	230.00	1S	0.16		2
10		Escondido	230.00	230.00	1S	0.21		2
11	Miguel		230.00	230.00	3	23.91		2
12			230.00	230.00	3	3.42		1
13		Sycamore Canyon	230.00	230.00	1S	0.56		1
14	Miguel		230.00	230.00	3		23.91	2
15			230.00	230.00	3	3.02		1
16			230.00	230.00	1S	6.70		1
17			230.00	230.00	3	7.52		1
18			230.00	230.00	1S	14.78		1
19			230.00	230.00	3	9.11		1
20		Mission	230.00	230.00	3	2.04		1
21	Old Town	Mission	230.00	230.00	1S	3.86		2
22	Old Town	Mission	230.00	230.00	1S		3.85	2
23	Escondido		230.00	230.00	1S	5.02		1
24		Talega	230.00	230.00	3	46.03		1
25	Otay Mesa		230.00	230.00	1S	0.10		1
26		Tijuana	230.00	230.00	3	1.61		1
27	Otay Mesa		230.00	230.00	3, 1S		8.92	2
28		Miguel	230.00	230.00	3, 1S		8.92	2
29	Miguel		230.00	230.00	1S		24.61	2
30			230.00	230.00	3		0.67	2
31		Sycamore	230.00	230.00	3		3.62	2
32	Miguel		230.00	230.00	1S		9.59	2
33			230.00	230.00	4	2.26		1
34			230.00	230.00	4	0.76		1
35			230.00	230.00	4	0.03		1
36					TOTAL	1,522.55	389.85	390

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1			230.00	230.00	3		3.85	1
2			230.00	230.00	4	1.09		1
3			230.00	230.00	4	0.31		1
4			230.00	230.00	4	5.04		1
5			230.00	230.00	4	0.26		1
6		Old Town	230.00	230.00	4	0.99		1
7	Imperial Valley		230.00	230.00	2W	0.82		1
8		La Rosita	230.00	230.00	3	4.64		1
9	Palomar Gen.		230.00	230.00	1S		0.80	1
10			230.00	230.00	3		5.96	2
11			230.00	230.00	3	10.12		1
12			230.00	230.00	1S	4.75		1
13			230.00	230.00	3	1.55		1
14		Sycamore Canyon	230.00	230.00	1S	0.17		1
15	San Onofre		230.00	230.00	2S		0.47	2
16		Talega	230.00	230.00	3		6.43	1
17	TOTAL 230kV LENGTHS					256.02	189.80	116
18								
19	Encina		138.00	230.00	1S	0.13		2
20		Cannon	138.00	230.00	1S	0.10		2
21	San Luis Rey		138.00	138.00	1S		0.23	2
22			138.00	138.00	3	0.70		2
23			138.00	138.00	1W	0.50		1
24			138.00	138.00	2W	0.89		1
25			138.00	138.00	2W	2.45		1
26		Shadowridge	138.00	138.00	2W	1.60		1
27	Shadowridge		138.00	138.00	3	1.40		2
28		Calaveras Tap	138.00	138.00	2W	0.46		1
29	San Luis Rey	Calaveras Tap	138.00	138.00	1W	4.03		1
30	Encina		138.00	138.00	1S	0.63		2
31			138.00	138.00	3	0.70		2
32			138.00	138.00	2W	19.58		1
33			138.00	138.00	4	0.60		1
34		Penasquitos	138.00	138.00	3	1.64		1
35	Palomar		138.00	138.00	1S	0.23		1
36					TOTAL	1,522.55	389.85	390

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1			138.00	138.00	4	0.71		1
2		Batiquitos	138.00	138.00	1S		1.81	2
3	Encina		138.00	138.00	1S	0.02		1
4			138.00	138.00	1S		2.00	2
5			138.00	138.00	3		0.01	2
6		Palomar	138.00	138.00	1S		1.05	2
7	Encina		138.00	138.00	1S	0.02		1
8			138.00	230.00	3		14.10	2
9		North City West	138.00	230.00	1S	1.13		1
10	North City West		138.00	230.00	2W		2.74	1
11			138.00	230.00	1S		0.09	1
12		Penasquitos	138.00	230.00	1S		0.08	2
13	Telegraph Canyon	Proctor Valley	138.00	230.00	1S	2.60		2
14	Friars		138.00	230.00	1S	1.98		1
15			138.00	138.00	3		9.31	2
16		Mission	138.00	138.00	1S	0.11		2
17	Doublet Tap	Penasquitos	138.00	138.00	3		0.58	1
18	Penasquitos	Doublet Tap	138.00	138.00	3	1.29		1
19	San Mateo	Talega	138.00	138.00	3	3.83		1
20	Main		138.00	138.00	3	0.21		1
21			138.00	138.00	3	6.43		1
22		South Bay	138.00	138.00	1W	0.08		1
23	Main	South Bay	138.00	138.00	3,1W		6.90	3
24	South Bay		138.00	138.00	3		3.60	3
25			138.00	138.00	1W, 1S		1.44	3
26		Grant Hill	138.00	138.00	4	4.16		1
27	Capistrano		138.00	138.00	3, 1S,W	0.10	1.55	1
28		Pico	138.00	138.00	3, 1S		4.82	1
29	Santee		138.00	138.00	1W, 1S	2.35		1
30			138.00	138.00	1S	4.24		2
31			138.00	138.00	3, 1S	0.34		1
32		Los Coches	138.00	138.00	3	0.04		1
33	Sycamore		138.00	138.00	1W	5.71		1
34		Chicarita	138.00	138.00	4	0.06		1
35	Carlton Hills		138.00	138.00	1S			2
36					TOTAL	1,522.55	389.85	390

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		Carlton Hills Tap	138.00	138.00	3		1.44	1
2	Carlton Hills Tap		138.00	138.00	3, 1S	1.37		2
3			138.00	138.00	1S		2.77	2
4		Santee	138.00	138.00	1W	1.56		1
5	Carlton Hills Tap		138.00	138.00	3	1.38		1
6		Sycamore	138.00	138.00	2W	3.85		1
7	Carlton Hills Tap		138.00	138.00	3		8.00	2
8		Mission	138.00	138.00	3	1.69		1
9	Telegraph Canyon		138.00	138.00	2S	6.66		2
10			138.00	138.00	3	0.08		1
11		South Bay	138.00	138.00	3		0.03	1
12	Los Coches		138.00	138.00	3		9.04	2
13			138.00	138.00	3		15.30	2
14		South Bay	138.00	138.00	3		0.80	2
15	North City Mtr Tap	Meadowlark Tap	138.00	138.00	3		7.40	2
16	Batiquitos	Meadowlark Tap	138.00	138.00	1S	2.58		2
17	Chicarita	Meadowlark Tap	138.00	138.00	2W	12.04		1
18	Shadowridge	Meadowlark Tap	138.00	138.00	3,1W	3.99		2
19	Miguel		138.00	138.00	3	1.29		2
20		Proctor Valley	138.00	138.00	1W	0.05		1
21	Friars		138.00	138.00	4	0.11		2
22		Mission	138.00	138.00	3	1.22		2
23	Margarita		138.00	230.00	1S	0.78		1
24		Trabuco	138.00	138.00	4	3.32		1
25	Talega	Margarita	138.00	230.00	1S	9.04		1
26	Talega		138.00	138.00	1W	1.72		1
27		Trabuco	138.00	138.00	3		15.41	2
28	Trabuco		138.00	138.00	1W	3.70		1
29			138.00	138.00	1W	0.01		1
30		Capistrano	138.00	138.00	1W	0.02		1
31	San Mateo Tap		138.00	138.00	1W	1.00		1
32		Talega	138.00	138.00	1W	0.37		2
33	Laguna Niguel		138.00	138.00	1W	1.00		1
34			138.00	138.00	3		2.00	2
35			138.00	138.00	1S		0.50	2
36					TOTAL	1,522.55	389.85	390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1			138.00	138.00	2W	1.00		1
2			138.00	138.00	2W	3.73		1
3		San Mateo Tap	138.00	138.00	2W	1.00		2
4	San Mateo Tap		138.00	138.00	1W	0.49		1
5		San Mateo	138.00	138.00	2W	3.00		1
6	Pico		138.00	138.00	3, 1S		0.68	2
7		Talega	138.00	138.00	1W, S	0.11	0.32	2
8	Capistrano		138.00	138.00	1W	0.32		1
9			138.00	138.00	1W	0.01		1
10			138.00	138.00	1W	0.02		1
11		Laguna Niguel	138.00	138.00	1W	2.66		1
12	Mission		138.00	138.00	1S, W	2.94		2
13		Grant Hill	138.00	138.00	4	2.84		1
14	138KV DEAD					13.95	13.95	
15	TOTAL 138kV LENGTH					161.95	127.95	145
16								
17	69kV LINES				1W	722.25	25.40	125
18					2W	4.31	1.38	
19					1S	31.42	1.50	
20					3	20.00	43.22	
21					4	47.60	0.60	
22	TOTAL 69kV LENGTH					825.58	72.10	125
23								
24								
25	Expenses, Except ISO							
26	Cost of Line							
27	ISO Charges							
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,522.55	389.85	390

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-2156 ACSR								1
2-2156 ACSR								2
2-2156 ACSR								3
2-2156 ACSR								4
								5
								6
1033.5 ACSR								7
1033.5 ACSR								8
1033.5 ACSR								9
1033.5 ACSR								10
2-1033.5 ACSR								11
1033.5 ACSR								12
1033.5 ACSR								13
2-1033.5 ACSR								14
2-1109 ACAR								15
1033.5 ACSR								16
1033.5 ACSR								17
1033.5 ACSR								18
1033.5 ACSR								19
2-1033.5 ACSR								20
1033.5 ACSR								21
2-1033.5 ACSR								22
2-1033.5 ACSR								23
1033.5 ACSR								24
1033.5 ACSR								25
1033.5 ACSR								26
2-1109 ACAR								27
2-1033.5 ACSR								28
2-1109 ACAR								29
2-1109 ACAR								30
2-1109 ACAR								31
2-1109 ACAR								32
2-900 ACSS								33
2-1109 ACAR								34
2-1109 ACAR								35
	59,606,167	723,215,656	782,821,823	59,907,711	10,213,351	1,579,539	71,700,601	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-1109 ACAR								1
2-1109 ACAR								2
2-1109 ACAR								3
2-1033.5 ACSR								4
2-1109 ACAR								5
2-1033.5 ACSR								6
900 ACSS								7
605 ACSS								8
900 ACSS								9
605 ACSS								10
2-1033.5 ACSR								11
2-1109 ACAR								12
2-1033.5 ACSR								13
2-1033.5 ACSR								14
2-1109 ACAR								15
2-1109 ACAR								16
1109 ACAR								17
636 ACSS								18
605 ACSS								19
1033.5 ACSR								20
1109 ACAR								21
1109 ACAR								22
1033.5 ACSR								23
1033.5 ACSR								24
2-900 ACSR								25
2-1033.5 ACSR								26
2-900 ACSS								27
2-900 ACSS								28
1033.5 ACSR								29
605 ACSR								30
1109 ACAR								31
2-900 ACSS								32
2-3500 KCMIL CU								33
2-4000 KCMIL								34
2-3500 KCMIL								35
	59,606,167	723,215,656	782,821,823	59,907,711	10,213,351	1,579,539	71,700,601	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1-900 ACSS								1
2-3500 KCMIL CU								2
2-2500 KCMIL CU								3
2-3500 KCMIL CU								4
2-2500 KCMIL CU								5
2-3500 KCMIL CU								6
1033.5 ACSR								7
1033.5 ACSR								8
2-900 ACSS								9
2-1109 ACAR								10
2-1109 ACAR								11
2-1109 ACAR								12
2-1109 ACAR								13
2-1033.5 ACSR								14
2-1033.5 ACSR								15
1033.5 ACSR								16
								17
								18
636 ACSR								19
2-1109 ACAR								20
2-1109 ACAR								21
2-1109 ACAR								22
1033.5 ACSR								23
1033.5 ACSR								24
400 MCM CU								25
400 MCM CU								26
250 MCM CU								27
250 MCM CU								28
1033.5 ACSR								29
2-1109 ACAR								30
2-1109 ACAR								31
2-636 ACSR								32
1033.5 ACSR								33
2-636 ACSR								34
2-1109 ACAR								35
	59,606,167	723,215,656	782,821,823	59,907,711	10,213,351	1,579,539	71,700,601	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-1109 ACAR								1
2-1109 ACAR								2
2-1033.5 ACSR								3
2-1109 ACAR								4
2-1109 ACAR								5
2-1109 ACAR								6
2-1033.5 ACSR								7
2-1109 ACAR								8
636 ACSR								9
2-1109 ACAR								10
2-1109 ACAR								11
2-1033.5 ACSR								12
2-1109 ACAR								13
400 MCM CU								14
400 MCM CU								15
636 ACSR								16
636 ACSR								17
1033.5 ACSR								18
636 ACSR								19
1033.5 ACSR								20
2-400 MCM CU								21
1033.5 ACSR								22
1033.5 ACSR								23
2-1033.5 ACSR								24
2-636 ACSR								25
2500 MCM CU								26
1033.5 ACSR								27
636 ACSR								28
1033.5 ACSR								29
605 ACSS								30
2-336.4 ACSR								31
1-750 MCM CU								32
636 ACSR								33
1750 KCMIL								34
1033.5 ACSR								35
	59,606,167	723,215,656	782,821,823	59,907,711	10,213,351	1,579,539	71,700,601	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-336.4 ACSR								1
2-336.4 ACSR								2
605 ACSS								3
636 ACSS								4
336.4 ACSR								5
636 ACSS								6
2-336.4 ACSR								7
2-336.4 ACSR								8
1033.5 ACSR								9
1033.5 ACSR								10
2-636 ACSR								11
2-400 MCM CU								12
2-636 ACSR								13
636 ACSR								14
1033.5 ACSR								15
636 ACSR								16
250 MCM CU								17
250 MCM CU								18
1033.5 ACSR								19
2-636 ACSR								20
2-636 ACSR								21
1033.5 ACSR								22
1750 AL UG								23
1033.5 ACSR								24
1033.5 ACSR								25
394.5 5005								26
394.5 5005								27
636 ACSR								28
336.4 ACSR								29
336.4 ACSR								30
636 ACSR								31
336.4 ACSR								32
336.4 ACSR								33
336.4 ACSR								34
336.4 ACSR								35
	59,606,167	723,215,656	782,821,823	59,907,711	10,213,351	1,579,539	71,700,601	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397 ACSR								1
250 MCM CU								2
1033.5 ACSR								3
250 MCM CU								4
336.4 ACSR								5
636 ACSR								6
1033.5 ACSR								7
636 ACSR								8
336.4 ACSR								9
336.4 ACSR								10
336.4 ACSR								11
636 ACSR								12
2500 MCM CU								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
				1,504,677	10,213,351	1,579,539	13,297,567	25
	59,606,167	723,215,656	782,821,823					26
				58,403,034			58,403,034	27
								28
								29
								30
								31
								32
								33
								34
								35
	59,606,167	723,215,656	782,821,823	59,907,711	10,213,351	1,579,539	71,700,601	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 2 Column: f
San Diego Gas & Electric owns 85.64% and Imperial Irrigation District owns 14.36%.

Schedule Page: 422 Line No.: 3 Column: f
San Diego Gas & Electric owns 85.64% and Imperial Irrigation District owns 14.36%.

Schedule Page: 422 Line No.: 4 Column: f
Line has two sections: Palo Verde to North Gila, and North Gila to Colorado River. SDG&E owns 76.22% and 85.64%, respectively, while Arizona Public Service owns 23.78% and 14.36%, respectively.

Schedule Page: 422.5 Line No.: 15 Column: a
The data for various 138kV line segments have been adjusted from prior years to more accurately reflect current records.

Schedule Page: 422.5 Line No.: 26 Column: j
Costs available in total only.

Schedule Page: 422.5 Line No.: 26 Column: k
Costs available in total only.

Schedule Page: 422.5 Line No.: 26 Column: l
Costs available in total only.

Schedule Page: 422.5 Line No.: 26 Column: m
Costs available in total only.

Schedule Page: 422.5 Line No.: 26 Column: n
Costs available in total only.

Schedule Page: 422.5 Line No.: 26 Column: o
Costs available in total only.

Schedule Page: 422.5 Line No.: 27 Column: m
ISO charges listed separately showing incurred costs by Company for effects of electric deregulation on transmission line operations.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OVERHEAD						
2							
3	OTAY MESA		8.92	1S, 3		2	2
4							
5		MIGUEL	8.92	1S, 3		2	2
6							
7							
8	UNDERGROUND						
9							
10	RANCHO SANTA FE TAP	NORTH CITY WEST	0.14	4			
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		17.98			4	4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
900	ACSS	VERT 18'	230	7,488		8,408,473		8,415,961	3
									4
900	ACSS	VERT 18'	230						5
									6
									7
									8
									9
1750	KCMILA	VERT 9'	69			250,814		250,814	10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				7,488		8,659,287		8,666,775	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/17/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 3 Column: c
To report addition of 8.92 miles for TL23041 from Otay Mesa to Miguel for 2008.

Schedule Page: 424 Line No.: 5 Column: c
To report addition of 8.92 miles for TL23042 from Otay Mesa to Miguel for 2008.

Schedule Page: 424 Line No.: 10 Column: c
To report addition of 0.14 miles for TL674 from Rancho Santa Fe Tap to North City West for 2008.

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Alpine, Alpine	Dist. Unattended	69.00	12.00	
2	Artesian, San Diego	Dist. Unattended	69.00	12.00	
3	Ash, Escondido	Dist. Unattended	69.00	12.00	
4	Avocado, Fallbrook	Dist. Unattended	69.00	12.00	
5	B, San Diego	Dist. Unattended	69.00	12.00	
6	Barrett, Barrett	Dist. Unattended	69.00	12.00	
7	Batiquitos, Encinitas	Dist. Unattended	138.00	12.00	
8	Bernardo, Rancho Bernardo	Dist. Unattended	69.00	12.00	
9	Border, San Diego	Dist. Unattended	69.00	12.00	
10	Borrego, Borrego Springs	Dist. Unattended	69.00	12.00	
11	Cabrillo, San Diego	Dist. Unattended	69.00	12.00	
12	Cannon, Carlsbad	Dist. Unattended	138.00	12.00	
13	Capistrano, San Juan Capistrano	Dist. Unattended	138.00	12.00	
14	Carlton Hills, Santee	Dist. Unattended	138.00	12.00	
15	Chicarita, San Diego	Dist. Unattended	138.00	12.00	
16	Chollas, Lemon Grove	Dist. Unattended	69.00	12.00	
17	Clairemont, San Diego	Dist. Unattended	69.00	12.00	
18	Coronado, Coronado	Dist. Unattended	69.00	12.00	
19	Creelman, Ramona	Dist. Unattended	69.00	12.00	
20	Crestwood	Dist. Unattended	69.00	12.00	
21	Del Mar, Del Mar	Dist. Unattended	69.00	12.00	
22	Division, San Diego	Dist. Unattended	69.00	12.00	
23	Eastgate, San Diego	Dist. Unattended	69.00	12.00	
24	El Cajon, El Cajon	Dist. Unattended	69.00	12.00	
25	Elliott, Grantville	Dist. Unattended	69.00	12.00	
26	Encinitas, Encinitas	Dist. Unattended	69.00	12.00	
27	Encinitas, Encinitas	Dist. Unattended	12.00	4.00	
28	Esco, Escondido	Dist. Unattended	69.00	12.00	
29	Esco, Escondido	Dist. Unattended	12.00	4.00	
30	Escondido, Escondido	Dist. Unattended	69.00	12.00	
31	F., San Diego	Dist. Unattended	69.00	12.00	
32	Fashion Valley, San Diego	Dist. Unattended	69.00	12.00	
33	Felicitia, Escondido	Dist. Unattended	69.00	12.00	
34	Friars, San Diego	Dist. Unattended	138.00	12.00	
35	Garfield, San Diego	Dist. Unattended	69.00	12.00	
36	Genesee, San Diego	Dist. Unattended	69.00	12.00	
37	Granite, El Cajon	Dist. Unattended	69.00	12.00	
38	Grant Hill, San Diego	Dist Unattended	138.00	12.00	
39	Imperial Beach, Imperial Beach	Dist. Unattended	69.00	12.00	
40	Imperial Beach, Imperial Beach	Dist. Unattended	12.00	4.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2009	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Jamacha, Jamacha	Dist. Unattended	69.00	12.00	
2	Japanese Mesa, San Clemente	Trans. Unattended	69.00	12.00	
3	Kearny, San Diego	Dist. Unattended	69.00	12.00	
4	Kettner, San Diego	Dist. Unattended	69.00	12.00	
5	La Jolla, La Jolla	Dist. Unattended	69.00	12.00	
6	Laguna Niguel, Laguna Niguel	Dist. Unattended	138.00	12.00	
7	Lilac, Valley Center	Dist. Unattended	69.00	12.00	
8	Los Coches, Lakeside	Dist. Unattended	69.00	12.00	
9	Loveland, Alpine	Dist. Unattended	69.00	12.00	
10	Margarita, Mission Viejo	Dist. Unattended	138.00	12.00	
11	Melrose, Vista	Dist. Unattended	69.00	12.00	
12	Mesa Heights, San Diego	Dist. Unattended	69.00	12.00	
13	Mesa Rim, San Diego	Dist. Unattended	69.00	12.00	
14	Miramar, Miramar	Dist. Unattended	69.00	12.00	
15	Mission, San Diego	Dist. Unattended	69.00	12.00	
16	Monserate, Monserate	Dist. Unattended	69.00	12.00	
17	Montgomery, Chula Vista	Dist. Unattended	69.00	12.00	
18	Morro Hill, E/O Oceanside	Dist. Unattended	69.00	12.00	
19	Murray, La Mesa	Dist. Unattended	69.00	12.00	
20	National City, National City	Dist. Unattended	69.00	4.00	12.00
21	North City West, San Diego	Dist. Unattended	69.00	12.00	
22	Oceanside, Oceanside	Dist. Unattended	69.00	12.00	
23	Old Town, San Diego	Dist. Unattended	69.00	12.00	
24	Otay, Otay	Dist. Unattended	69.00	12.00	
25	Olivenhain, Escondido	Dist. Unattended	69.00	12.00	
26	Pacific Beach, San Diego	Dist. Unattended	69.00	12.00	
27	Pala, San Diego County	Dist. Unattended	69.00	12.00	
28	Palomar Airport, E/O Carlsbad	Dist. Unattended	138.00	12.00	
29	Paradise, San Diego	Dist. Unattended	69.00	12.00	
30	Pendelton, Camp Pendelton	Dist. Unattended	69.00	12.00	
31	Pico, San Clemente	Dist. Unattended	138.00	12.00	
32	Point Loma, San Diego	Dist. Unattended	69.00	12.00	12.00
33	Point Loma, San Diego	Dist. Unattended	12.00	4.00	
34	Pomerado, San Diego	Dist. Unattended	69.00	12.00	
35	Poway, Poway	Dist. Unattended	69.00	12.00	
36	Proctor Valley, Bonita	Dist. Unattended	138.00	12.00	
37	Rancho Carmel, San Diego	Dist. Unattended	69.00	12.00	
38	Rancho Santa Fe, Rancho Santa Fe	Dist. Unattended	69.00	12.00	
39	Rancho Sante Fe, Rancho Santa Fe	Dist. Unattended	69.00	4.00	
40	Rincon, Rincon	Dist. Unattended	69.00	12.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Rolando, San Diego	Dist. Unattended	12.00	4.00	
2	Rose Canyon, San Diego	Dist. Unattended	69.00	12.00	
3	Sampson, San Diego	Dist. Unattended	69.00	12.00	
4	San Luis Rey, Oceanside	Dist. Unattended	69.00	12.00	
5	San Marcos, San Marcos	Dist. Unattended	69.00	12.00	
6	San Mateo, San Clemente	Dist. Unattended	138.00	12.00	
7	San Ysidro, San Ysidro	Dist. Unattended	69.00	12.00	
8	Santa Ysabel, Santa Ysabel	Dist. Unattended	69.00	12.00	
9	Santee, Santee	Dist. Unattended	138.00	12.00	
10	Scripps, San Diego	Dist. Unattended	69.00	12.00	
11	Shadowridge, Vista	Dist. Unattended	138.00	12.00	
12	Spring Valley, Spring Valley	Dist. Unattended	69.00	12.00	
13	Streamview, San Diego	Dist. Unattended	69.00	12.00	
14	Sunnyside, San Diego	Dist. Unattended	69.00	12.00	
15	Sweetwater, National City	Dist. Unattended	69.00	12.00	
16	Sweetwater, National City	Dist. Unattended	69.00	4.00	
17	Telegraph Canyon, Chula Vista	Dist. Unattended	138.00	12.00	
18	Torrey Pines, La Jolla	Dist. Unattended	69.00	12.00	
19	Trabuco, Capistrano	Dist. Unattended	138.00	12.00	
20	Urban, San Diego	Dist. Unattended	69.00	12.00	
21	Valley Center, Valley Center	Dist. Unattended	69.00	12.00	
22	Vista, Vista	Dist. Unattended	12.00	4.00	
23	Wabash, San Diego	Dist. Unattended	69.00	4.00	
24	Escondido, Escondido	Trans. Unattended	230.00	69.00	
25	Escondido, Escondido	Trans. Unattended	138.00	69.00	
26	Imperial Valley, El Centro	Trans. Unattended	500.00	230.00	
27	Los Coches, Lakeside	Trans. Unattended	138.00	69.00	
28	Main Street, San Diego	Trans. Unattended	138.00	69.00	
29	Miguel, Bonita	Trans. Unattended	230.00	69.00	
30	Miguel, Bonita	Trans. Unattended	230.00	138.00	
31	Miguel, Bonita	Trans. Unattended	500.00	230.00	
32	Miramar, GT, Miramar	Trans. Unattended	12.00	69.00	
33	Mission, San Diego	Trans. Unattended	230.00	138.00	
34	Mission, San Diego	Trans. Unattended	230.00	69.00	
35	Mission, San Diego	Trans. Unattended	138.00	69.00	
36	Narrows, Borrego Springs	Trans. Unattended	88.00	69.00	12.00
37	Old Town, San Diego	Trans. Unattended	230.00	69.00	
38	Penasquitos, San Diego	Trans. Unattended	230.00	69.00	
39	Penasquitos, San Diego	Trans. Unattended	230.00	138.00	
40	Penasquitos, San Diego	Trans. Unattended	138.00	69.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	San Luis Rey, Oceanside	Trans. Unattended	230.00	69.00	
2	San Luis Rey, Oceanside	Trans. Unattended	138.00	69.00	
3	Silvergate Substation, San Diego	Trans. Unattended	230.00	69.00	
4	South Bay, Chula Vista	Trans. Unattended	138.00	69.00	
5	Sycamore, San Diego	Trans. Unattended	230.00	69.00	
6	Sycamore, San Diego	Trans. Unattended	230.00	138.00	
7	Talega, E/O San Clemente	Trans. Unattended	230.00	138.00	
8	Talega, E/O San Clemente	Trans. Unattended	138.00	69.00	
9					
10					
11	Transmission	10795 MVa Total			
12	Distribution	6678 MVa Total			
13	Total Substation		13132.00	3548.00	36.00
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	2					1
28	1					2
84	3					3
41	2					4
112	4					5
13	1					6
56	2					7
140	5					8
56	2					9
26	2					10
56	2					11
56	2					12
56	2					13
56	2					14
84	3					15
84	3					16
56	2					17
56	2					18
84	3					19
13	1					20
84	3					21
53	2					22
56	2					23
112	4					24
56	2					25
56	2					26
6	1					27
56	2					28
4	1					29
84	3					30
84	3					31
13	1					32
84	3					33
56	2					34
28	1					35
112	4					36
112	4					37
56	2					38
56	2					39
6	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
84	3					1
16	2					2
84	3					3
56	2					4
56	2					5
112	4					6
56	2					7
84	3					8
28	1					9
112	4					10
112	4					11
56	2					12
112	4					13
84	3					14
122	4					15
56	2					16
56	2					17
13	1					18
112	4					19
14	2					20
56	2					21
56	2					22
84	3					23
56	2					24
28	1					25
56	2					26
28	1					27
84	3					28
56	2					29
56	2					30
56	2					31
84	2					32
6	1					33
84	3					34
56	2					35
56	3					36
84	3					37
41	2					38
6	1					39
25	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
13	2					1
56	2					2
112	4					3
112	4					4
84	3					5
45	2					6
56	2					7
12	1					8
56	2					9
84	3					10
84	3					11
56	2					12
56	2					13
14	1					14
56	2					15
13	2					16
84	3					17
112	4					18
112	4					19
84	3					20
28	1					21
10	2					22
13	2					23
672	3					24
67	1					25
1200	6	5				26
290	2					27
300	2					28
448	2					29
392	1	1				30
2240	6	1				31
50	1					32
784	2					33
224	1					34
499	5					35
10	3					36
448	2					37
448	2					38
392	1					39
420	3	1				40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
448	2	1				1
140	1					2
448	2					3
224	1					4
448	2					5
392	1					6
1102	4					7
25	1					8
						9
						10
						11
						12
18333	299	9				13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule	Page No.

INDEX (continued)

Schedule	Page No.

Schedule	Page No.

INDEX (continued)

Schedule | Page No.

Document Content(s)