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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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 2015/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	02 Year/Period of Report
San Diego Gas & Electric Company	End of 2015/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, CA 92123

05 Name of Contact Person	06 Title of Contact Person
Eric Dalton	Regulatory Reporting Manager

07 Address of Contact Person *(Street, City, State, Zip Code)*
488 8th Ave, San Diego, CA 92101

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(858) 503-5130	(1) ☒ An Original (2) ☐ A Resubmission	/ /

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 / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name: Bruce Folkmann 02 Title: VP, Controller, CFO, CAO, Treasurer	Bruce Folkmann	04/15/2016

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".

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	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two 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	/ /	End of 2015/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.

Bruce A. Folkmann, Vice President, Controller, Chief Financial Officer, Chief Accounting Officer, and Treasurer

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

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 beneficieary for whom trust was maintained, and purpose of the trust.

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

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			
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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	/ /	End of 2015/Q4

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	Chairman, President and Chief Executive Officer	Jeffrey W. Martin	546,700
2	President and Chief Operating Officer (1)	Steven D. Davis	541,400
3	Chief Development Officer	James P. Avery	367,800
4	Chief Administrative Officer	Lee Schavrien	367,700
5	Chief Information Officer	J. Chris Baker	361,100
6	Senior Vice President, General Counsel	Erbin B. Keith	360,200
7	and Assistant Secretary		
8	Chief Energy Supply Officer	Scott D. Drury	310,000
9	Chief Energy Delivery Officer	Caroline A. Winn	310,000
10	Chief Financial Officer, Vice President, Treasurer,	Robert M. Schlax	285,300
11	Controller & Chief Accounting Officer (2)		
12	Chief Financial Officer, Vice President, Treasurer,	Bruce A. Folkmann	273,000
13	Controller & Chief Accounting Officer		
14	Corporate Secretary	Kari E. McCulloch	225,500
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22	(1) Steven D. Davis resigned as President and Chief		
23	Operating Officer effective September 25, 2015.		
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25	(2) Robert M. Schlax resigned as Chief Financial		
26	Officer, Treasurer, Controller & Chief Accounting		
27	Officer effective March 27, 2015.		
28	Mr. Schlax resigned as Vice President effective		
29	July 31, 2015.		
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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	/ /	End of 2015/Q4

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	Jessie J. Knight, Director and Chairman (1)(2)	San Diego, CA
2	Steven D. Davis, Director (1)	San Diego, CA
3	Joseph A. Householder, Director (1)(3)	San Diego, CA
4	Jeffrey W. Martin, Director, Chairman, CEO and President	San Diego, CA
5	G. Joyce Rowland, Director (1)	San Diego, CA
6	Martha B. Wyrsch, Director (1)	San Diego, CA
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12	(1) Does not hold any offices with SDG&E but are officers	
13	of SDG&E's ultimate parent, Sempra Energy.	
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15	(2) Mr. Knight resigned as Director and Chairman effective	
16	November 1, 2015.	
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18	(3) Mr. Householder resigned as Director effective	
19	September 2, 2015.	
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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	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1		
2	FERC Electric Tariff, Volume No.11	ER15-553-000
3		
4		
5	FERC Electric Tariff, Volume No.11	ER15-1410-000
6		
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8	FERC Electric Tariff, Volume No.11	ER15-1817-000
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11	FERC Electric Tariff, Volume No.11	ER15-1798-000
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14	FERC Electric Tariff, Volume No.11	ER15-2215-000
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17	FERC Electric Tariff, Volume No.11	ER15-175-000
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20	FERC Electric Tariff, Volume No.11	ER15-679-000
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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	/ /	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1					
2	20141201-5301	12/01/2014	ER15-553-000	TO4 Cycle 2 Formula Rate	FERC Electric Tariff, Volume No.11
3				Annual Informational Filing	
4					
5	20150331-5506	03/31/2015	ER15-1410-000	Appendix X Formula	FERC Electric Tariff, Volume No.11
6				Modificaton Filing	
7					
8	20150529-5344	05/29/2015	ER15-1817-000	Cycle 4 Appendix X	FERC Electric Tariff, Volume No.11
9				Annual Informational Filing	
10					
11	20150528-5194	05/28/2015	ER15-1798-000	Post-Employment Benefits Other	FERC Electric Tariff, Volume No.11
12				Than Pensions ("PBOP") Filing	
13					
14	20150716-5135	07/16/2015	ER15-2215-000	TO4 Formula Depreciation	FERC Electric Tariff, Volume No.11
15				Rate Change Filing	
16					
17	20141023-5141	10/23/2014	ER15-175-000	2015 Reliability Service Balancing	FERC Electric Tariff, Volume No.11
18				Account ("RSBA") Filing	
19					
20	20141219-5329	12/19/2014	ER15-679-000	2015 Transmission Revenue Balancing	FERC Electric Tariff, Volume No.11
21				Account Adjustment ("TRBAA") and	
22				Transmission Access Charge	
23				Balancing Account Adjustment	
24				("TACBAA") Filing	
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INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1		See page 106 and 106a		
2				
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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 104 or 105 of the Annual Report Form No. 1, 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.

1. None

2. None

3. None

4. None

5. Distribution Changes: SDG&E added circuits 1202 (San Ysidro substation), and circuits 1244 and 1245 (Rancho Mission Viejo) to the distribution system in 2015.

   On December 18, 2015 at 0902 SDG&E assumed control of Merchant substation and on November 20, 2015, placed new 230/138KV BK 61 in service.

6. Short Term Debt:

   SDG&E issued short-term debt in the form of commercial paper during the 4th quarter of 2015. The average daily outstanding was $55.1 million with a maximum daily outstanding of $179.9 million. There was $167.9 million outstanding as of December 31, 2015.

   Long Term Debt:

   In the fourth quarter, SDG&E had no long term debt issuance. The $250 million, 5.3 percent first mortgage bonds matured on November 15, 2015.

7. None

8. On December 18, 2015, SDG&E employees represented by the International Brotherhood of Electrical Workers (IBEW) Local 465 received a retroactive negotiated base rate increase of 2.75% effective back to September 1, 2015, affecting 1214 employees:

   - Total annual base wages for represented employees in 2015 were $3.59 million above 2014 base wages.

   - Total annual wages for represented employees including overtime in 2015 were $8.26 million above 2014 wages including overtime.

9. Please refer to the Legal Proceedings section of the Notes to the Financial Statements on page 123.56.

10. None

11. N/A

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

13. Changes in Officers:

Name	Title	Effective Date
Eugene Mitchell	Vice President - State Government Affairs changed to Vice President State Governement Affairs and External Affairs	Title Changed, 02/07/2015

Lee Schavrien	Senior Vice President - Finance, Regulatory and Legislative Affairs changed to Senior Vice President of Regulatory Affairs and Operations Support	Title Changed, 02/07/2015
Michael M. Scheider	Vice President - Operations Support changed to Vice President - Operations Support and Chief Environmental Officer	Title Changed, 02/07/2015
Denita A. Willoughby	Vice President of Supply Management and Logistics	Elected, 02/07/2015
Robert M. Schlax	Chief Financial Officer, Controller, Chief Accounting Officer and Treasurer (Vice President Title Retained)	Resigned/Title Retained,03/27/2015
Bruce A. Folkmann	Chief Financial Officer, Controller, Chief Accounting Officer and Treasurer	Elected, 03/28/2015
James P. Avery	Senior Vice President - Power Supply changed to Chief Development Officer	Title Changed, 06/06/2015
J. Christopher Baker	Senior Vice President and Chief Information Officer changed to Chief Information Officer	Title Changed, 06/06/2015
Scott D. Drury	Vice President - Human Resources, Diversity and Inclusion changed to Chief Energy Supply Officer	Title Changed, 06/06/2015
Lee Schavrien	Senior Vice President of Regulatory Affairs and Operations Support changed to Chief Administrative Officer	Title Changed, 06/06/2015
Caroline A. Winn	Senior Vice President - Power Supply changed to Chief Energy Delivery Officer	Title Changed, 06/06/2015
Robert M. Schlax	Vice President	Retired, 07/31/2015
Victor E. Vilapana	Vice President - Electric and Fuel Procurement changed to Vice President - Customer Services	Title Changed, 08/29/2015
Emily C. Shults	Vice President – Electric & Fuel Procurement	Elected, 08/29/2015
Victor E. Vilaplana	Vice President – Customer Services	Resigned, 09/15/2015
Steven D. Davis	President and Chief Operating Officer	Resigned, 09/25/2015
Randall L. Clark	Vice President - Human Resources,	Elected, 10/10/2015

	Diversity and Inclusion	
Jeffery W. Martin	President	Elected, 10/10/2015
Jeffery W. Martin	Chairman	Elected, 10/10/2015

Changes in Directors:

Name	Effective Date
Martha B. Wyrsch	Elected, 01/20/2015
Joseph A. Householder	Resigned, 09/02/2015
G. Joyce Rowland	Elected, 09/03/2015
Jessie J. Knight Jr.	Resigned, 11/01/2015

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

14. N/A

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2015/Q4

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	15,583,922,588	14,623,691,692
3	Construction Work in Progress (107)	200-201	923,122,087	910,039,589
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,507,044,675	15,533,731,281
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	5,361,217,298	4,964,788,547
6	Net Utility Plant (Enter Total of line 4 less 5)		11,145,827,377	10,568,942,734
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
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	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		11,145,827,377	10,568,942,734
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,946,616	5,946,615
19	(Less) Accum. Prov. for Depr. and Amort. (122)		364,300	364,300
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	140,868,906	45,662,034
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)		1,063,117,470	1,131,021,297
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		51,171,501	79,386,394
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,260,740,193	1,261,652,040
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,246,123	3,168,373
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		500	500
38	Temporary Cash Investments (136)		13,200,000	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		269,828,712	224,616,006
41	Other Accounts Receivable (143)		16,592,327	35,390,390
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,918,499	3,928,074
43	Notes Receivable from Associated Companies (145)		812	0
44	Accounts Receivable from Assoc. Companies (146)		1,214,165	1,231,008
45	Fuel Stock (151)	227	5,493,301	7,521,721
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	104,583,010	100,373,918
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	157,498,037	109,816,816

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	/ /	End of 2015/Q4

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		140,868,906	45,662,034
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		359,925	345,925
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		7,902	15,005
57	Prepayments (165)		59,970,279	198,451,723
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		716,692	714,386
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		65,870,000	64,451,000
62	Miscellaneous Current and Accrued Assets (174)		2,304,840	2,540,350
63	Derivative Instrument Assets (175)		104,241,532	123,436,676
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		51,171,501	79,386,394
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)		606,169,251	743,097,295
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		31,553,245	33,220,663
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	291,073,906	356,557,312
72	Other Regulatory Assets (182.3)	232	2,888,083,183	3,248,855,958
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,035,440	4,963,452
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)		821,264	333,767
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	35,199,863	30,014,718
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)		12,292,404	12,083,237
82	Accumulated Deferred Income Taxes (190)	234	276,047,772	591,358,980
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		3,540,107,077	4,277,388,087
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		16,552,843,898	16,851,080,156

Schedule Page: 110 Line No.: 57 Column: c

The 13-Month Average Electric Prepayments for 2015 is $36,035,692.

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	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		591,282,978	591,282,978
7	Other Paid-In Capital (208-211)	253	479,665,369	479,665,368
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)	254b	24,605,640	24,605,640
11	Retained Earnings (215, 215.1, 216)	118-119	3,892,862,778	3,608,175,171
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)	-7,840,314	-11,998,026
16	Total Proprietary Capital (lines 2 through 15)		5,222,823,566	4,933,978,246
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,989,648,000	3,912,505,000
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	53,650,000	223,900,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		9,710,098	10,327,638
24	Total Long-Term Debt (lines 18 through 23)		4,033,587,902	4,126,077,362
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		631,433,074	655,885,021
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		29,917,817	28,829,083
29	Accumulated Provision for Pensions and Benefits (228.3)		217,194,669	220,581,904
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		83,203,290	122,010,536
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		826,441,431	871,879,253
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,788,190,281	1,899,185,797
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		114,260,980	245,572,061
38	Accounts Payable (232)		418,724,687	480,486,749
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		54,652,222	21,149,206
41	Customer Deposits (235)		71,665,653	71,379,130
42	Taxes Accrued (236)	262-263	2,029,475	166,987,400
43	Interest Accrued (237)		43,773,285	44,591,625
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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)		4,677,565	4,444,520
48	Miscellaneous Current and Accrued Liabilities (242)		228,176,465	302,454,605
49	Obligations Under Capital Leases-Current (243)		39,832,799	37,489,385
50	Derivative Instrument Liabilities (244)		119,723,777	146,624,987
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		83,203,290	122,010,536
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,014,313,618	1,399,169,132
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		54,829,188	36,839,313
57	Accumulated Deferred Investment Tax Credits (255)	266-267	18,728,931	21,615,165
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	333,162,681	309,715,655
60	Other Regulatory Liabilities (254)	278	1,366,188,958	1,406,095,528
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		2,031,630,223	1,975,475,446
64	Accum. Deferred Income Taxes-Other (283)		689,388,550	742,928,512
65	Total Deferred Credits (lines 56 through 64)		4,493,928,531	4,492,669,619
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		16,552,843,898	16,851,080,156

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	/ /	End of 2015/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
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 column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. 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.

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	4,809,317,693	5,138,995,326		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,968,444,719	3,422,546,042		
5	Maintenance Expenses (402)	320-323	143,626,230	155,271,046		
6	Depreciation Expense (403)	336-337	453,392,042	429,606,101		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	65,809,850	56,952,111		
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)		57,699,676	16,185,370		
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	126,821,543	114,434,033		
15	Income Taxes - Federal (409.1)	262-263	11,172,935	-5,161,557		
16	- Other (409.1)	262-263	113,208,682	51,094,771		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	570,853,458	1,020,664,504		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	394,291,215	803,595,539		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,886,234	-2,245,608		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
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)		4,113,867,430	4,455,767,018		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		695,450,263	683,228,308		

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		
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)	Line No.
						1
4,304,455,432	4,593,689,814	507,638,955	547,398,773	-2,776,694	-2,093,261	2
						3
2,641,565,272	3,046,521,871	332,176,224	381,666,170	-5,296,777	-5,641,999	4
120,975,470	138,559,118	22,650,760	16,711,928			5
405,451,532	378,644,480	45,773,036	48,051,031	2,167,474	2,910,590	6
						7
56,012,444	48,122,782	9,797,406	8,829,329			8
15,744	15,744					9
57,699,676	16,185,370					10
						11
						12
						13
111,187,066	99,489,284	14,966,079	14,300,735	668,398	644,014	14
7,277,252	-5,161,557	3,895,683				15
101,466,804	47,358,713	11,741,878	3,736,058			16
503,684,431	923,324,205	67,169,027	97,340,299			17
351,796,872	726,198,098	42,494,343	77,397,441			18
-2,355,653	-1,715,027	-530,581	-530,581			19
						20
						21
						22
						23
						24
3,651,183,166	3,965,146,885	465,145,169	492,707,528	-2,460,905	-2,087,395	25
653,272,266	628,542,929	42,493,786	54,691,245	-315,789	-5,866	26

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)		695,450,263	683,228,308		
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)		4,707	1,602		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		71,781	411,985		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		25,746,782	7,541,395		
38	Allowance for Other Funds Used During Construction (419.1)		37,153,836	37,118,230		
39	Miscellaneous Nonoperating Income (421)		696,606	1,560,404		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		63,673,712	46,633,616		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		250,048	250,048		
45	Donations (426.1)		7,296,545	7,206,347		
46	Life Insurance (426.2)		-4,967,255	-5,124,954		
47	Penalties (426.3)		18,337	55,558		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,745,671	1,941,492		
49	Other Deductions (426.5)		1,691,022	16,199,593		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,034,368	20,528,084		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	634,674	643,546		
53	Income Taxes-Federal (409.2)	262-263	-8,182,199			
54	Income Taxes-Other (409.2)	262-263	-17,648,091	1,944,220		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	120,444,225	23,157,299		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	98,959,713	17,123,884		
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)		-3,711,104	8,621,181		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		61,350,448	17,484,351		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		188,053,798	189,026,001		
63	Amort. of Debt Disc. and Expense (428)		3,313,278	3,210,416		
64	Amortization of Loss on Reaquired Debt (428.1)		2,807,389	2,392,942		
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)					
68	Other Interest Expense (431)		7,109,923	6,452,331		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		13,701,644	14,744,740		
70	Net Interest Charges (Total of lines 62 thru 69)		187,582,744	186,336,950		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		569,217,967	514,375,709		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)		-26,107,334	5,794,327		
75	Net Extraordinary Items (Total of line 73 less line 74)		26,107,334	-5,794,327		
76	Income Taxes-Federal and Other (409.3)	262-263	10,637,694	1,330,682		
77	Extraordinary Items After Taxes (line 75 less line 76)		15,469,640	-7,125,009		
78	Net Income (Total of line 71 and 77)		584,687,607	507,250,700		

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: l

Eliminates interdepartmental transfers	$ (7,677,023)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	$ 6,120,721
Other	$ (536,959)
	$ (2,093,261)

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

Total Operating Expenses excludes amounts associated with interdepartmental transfers.

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

Total Operating Expenses excludes amounts associated with interdepartmental transfers.

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

Eliminates interdepartmental transfers	$ (7,677,023)
Citizens Energy Corporation Operating Expenses	$ 2,035,024
	$ (5,641,999)

Schedule Page: 114 Line No.: 6 Column: l

Depreciation expenses related to the Citizens Energy Corporation lease	$2,837,197
Other	$ 73,393
	$2,910,590

Schedule Page: 114 Line No.: 14 Column: l

Citizens Energy Corporation Property Tax	$ 606,895
Citizens Energy Corporation Payroll Tax	$ 37,119
	$ 644,014

Schedule Page: 114 Line No.: 38 Column: c

Modification of the Alloance for Funds Used During Construction Rate

San Diego Gas and Electric (SDG&E) received FERC approval to modify its existing Allowance for Funds Used During Construction (AFUDC) rate by excluding certain short-term and long-term debt associated with the financing of the regulatory asset for the San Onfore Nuclear Generation Station (SONGS) Units 2 and 3.

Schedule Page: 114 Line No.: 49 Column: d

Abandoned Projects	$ 5,590,698
FERC Audit Adjustments	3,404,554
Accrued Legal Costs	5,800,000
Other Activity	1,404,341
Total	$ 16,199,593

Schedule Page: 114 Line No.: 69 Column: c

Modification of the Alloance for Funds Used During Construction Rate

San Diego Gas and Electric (SDG&E) received FERC approval to modify its existing Allowance for Funds Used During Construction (AFUDC) rate by excluding certain short-term and long-term debt associated with the financing of the regulatory asset for the San Onfore Nuclear Generation Station (SONGS) Units 2 and 3.

Schedule Page: 114 Line No.: 76 Column: c

The taxes relating to the extraordinary deductions of $26,107,334 are allocated as follows:

- State taxes: Account 409.3 = $2,307,888
- Federal Taxes: Account 409.3 = $8,329,806

Schedule Page: 114 Line No.: 76 Column: d

The extraordinary deductions for the SONGS impairment on line 74 of $5,794,327 have a related amount of tax in the amount of ($2,360,957) and are allocated as follows:

- State Taxes: Page 263, Account 409.3 = (512,219)
- Federal Taxes: Page 234, Account 411.1 = (1,848,738)

An additional disallowance of the deferred tax regulatory asset item relating to the Steam Generator Replacement Project of $3,691,639 was disallowed and is included in the extraordinary item tax line only and allocated as follows:

- State Taxes: Page 276, Account 410.1 = 800,915
- Federal Taxes: Page 276, Account 410.1 = 2,890,724

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		3,608,175,171	3,300,924,471
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		584,687,607	507,250,700
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				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-300,000,000	(200,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-300,000,000	(200,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,892,862,778	3,608,175,171
	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)		3,892,862,778	3,608,175,171
	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)			

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	/ /	End of 2015/Q4

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)	584,687,607	507,250,700
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	453,392,042	429,606,101
5	Amortization of Utility Acquisition Adjustment Poperty Losses		
6	Amortization of Unrecovered Plant and Regulatory Study Costs	123,525,270	73,153,225
7	Impairment of SONGS Asset	-26,107,334	5,794,327
8	Deferred Income Taxes (Net)	198,046,752	224,945,280
9	Investment Tax Credit Adjustment (Net)	-2,886,234	-2,245,608
10	Net (Increase) Decrease in Receivables	-26,826,375	-26,661,750
11	Net (Increase) Decrease in Inventory	-1,930,128	-34,350,967
12	Net (Increase) Decrease in Allowances Inventory	-117,347,728	-51,227,010
13	Net Increase (Decrease) in Payables and Accrued Expenses	-1,242,900	-136,006,464
14	Net (Increase) Decrease in Other Regulatory Assets	279,856,589	-51,102,323
15	Net Increase (Decrease) in Other Regulatory Liabilities	-17,013,093	83,904,555
16	(Less) Allowance for Other Funds Used During Construction	37,153,836	37,118,230
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: Net (Increase) Decrease in Prepayments and Other	166,678,998	258,536
19	Net Increase (Decrease) in Accrued Interest and Taxes	-165,545,528	53,915,072
20			
21	Other- net	193,030,198	21,549,950
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,603,164,300	1,061,665,394
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,169,605,307	-1,137,400,000
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-37,153,836	-37,118,230
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,132,451,471	-1,100,281,770
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-813	
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)		
45	Proceeds from Sales of Investment Securities (a)		

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	/ /	End of 2015/Q4

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	Other Investing Activites		-30,000,000
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 Purchase	-527,201,015	-608,866,535
54	Decommissioning Trust Fund Sales	577,478,782	601,688,060
55	Increase (Decrease) in Customer Advances for Construction	17,008,322	-3,036,141
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,065,166,195	-1,140,496,386
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	443,625,698	100,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Other: LTD Issuance Cost Amortization	-2,277,972	
66	Net Increase in Short-Term Debt (c)	-131,311,081	186,572,274
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	310,036,645	286,572,274
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-536,757,000	-14,350,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-300,000,000	-200,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-526,720,355	72,222,274
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	11,277,750	-6,608,718
87			
88	Cash and Cash Equivalents at Beginning of Period	3,168,873	9,777,586
89			
90	Cash and Cash Equivalents at End of period	14,446,623	3,168,868

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.

A. Notes for Statement of Cash Flows:

Supplemental Disclosure of Cash Flow Information:	12/31/2015
Income tax payments (refunds), net	$ 88,425,670
Interest payments, net of amounts capitalized	$180,471,712
Reconciliation of cash and cash equivalents at Dec 31, 2015:	
Account 131 Cash	$ 1,246,123
Account 135 Working Funds	$ 500
Account 136 Temporary Cash Investments	$13,200,000
	$14,446,623
Supplemental Disclosure of Non-Cash Investing Activities:	
Increase (Decrease) in capital lease obligation for investments in property, plant and equipment	$ 14,884,000
Accrued capital expenditures	$190,505,000

B. Basis of Presentation and Notes to Financial Statements

Beginning on page 123.3 are excerpts from Sempra Energy's (Sempra or the parent) Annual Report on Form 10-K for the period ending December 31, 2015, as filed with the Securities and Exchange Commission (SEC) on February 26, 2016. 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 Principles 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
- Certain cost of removal obligations and property reserves
- Classification of interest and penalties associated with income taxes
- Electricity sales for resale and purchase power expenses
- Certain revenues net of related costs
- Capital lease treatment of certain contracts, which are consolidated as variable interest entities (VIE) for GAAP purposes
- Certain plant in service, accumulated depreciation, and regulatory assets

Accordingly, certain Notes to the Financial Statements are not reflective of San Diego Gas & Electric's (SDG&E) Financial Statements contained herein, which have been prepared on a stand alone basis, which exclude consolidation with Otay Mesa Energy Center LLC's (OMEC) Financial Statements, and which include capital lease treatment for the OMEC power purchase agreement. We provide further detail in Note C.

Due to the differences between FERC and SEC reporting requirements as mentioned above, certain amounts disclosed in Notes 1-12 may not agree to balances in the FERC financial statements.

C. Other FERC Related Disclosures

FERC Capital Leases

The following agreement is accounted for as a capital lease under FERC accounting requirements and consolidated as a variable interest entity under GAAP requirements.

Otay Mesa Energy Center, LLC Power Purchase Agreement

We have an agreement through 2019 to purchase power generated at OMEC, a 605-megawatt generating facility that began commercial operation in October 2009. We supply all of the natural gas to fuel the power plant, and we purchase its full electric generation output. As of December 31, 2015, the capital lease was valued at $595 million, and the corresponding capital lease obligation with a 10-year term was valued at $427 million.

At December 31, 2015, the future minimum lease payments and present value of the net minimum lease payments under these capital leases were as follows:

(Dollars in millions)		
2016	$	67
2017		67
2018		67
2019		331
Total minimum lease payments(1)		532
Less: interest(2)		(105)
Present value of net minimum lease payments(3)	$	427

(1) *This amount will be recorded over the life of the lease as Cost of Electric Fuel and Purchased Power on our Statement of Operations. This expense will receive ratemaking treatment consistent with purchased-power costs.*

(2) *Amount necessary to reduce net minimum lease payments to present value at the inception of the leases.*

(3) *Includes $35 million in Current Portion of Capital Lease Obligation and $392 million in Long-Term Capital Lease Obligation on the Balance Sheet at December 31, 2015.*

The annual amortization charge for the OMEC power purchase agreement was $33 million for 2015 and $30 million for 2014.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

BASIS OF PRESENTATION

This is a report of San Diego Gas & Electric (SDG&E). SDG&E's common stock is wholly owned by Enova Corporation, which is a wholly owned subsidiary of Sempra Energy. Sempra Energy also indirectly owns all of the common stock of Southern California Gas Company (SoCalGas). References in this report to "we" and "our" are to SDG&E, unless otherwise indicated by the context. We refer to SDG&E and SoCalGas collectively as the California Utilities.

Use of Estimates in the Preparation of the Financial Statements

We have prepared our Financial Statements in conformity with U.S. 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.

Recognizable and nonrecognizable events (type 1 and type 2)

Management has evaluated the impact of events occurring after December 31, 2015 up to February 26, 2016, the date that these financial statements were available to be issued. These financial statements include all necessary adjustments and disclosures resulting from that evaluation.

REGULATORY MATTERS

Effects of Regulation

Our accounting policies conform with U.S. GAAP for rate-regulated enterprises and reflect the policies of the California Public Utilities Commission (CPUC) and FERC.

We prepare our financial statements in accordance with U.S. GAAP provisions governing rate-regulated operations. Under these provisions, a regulated utility records regulatory assets, which are generally costs that would otherwise be charged to expense, if it is probable that, through the ratemaking process, the utility will recover those assets from customers. To the extent that recovery is no longer probable, the related regulatory assets are written off. Regulatory liabilities generally 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. Regulatory liabilities may also arise from other transactions such as unrealized gains on fixed price contracts and other derivatives or certain deferred income tax benefits that are passed through to customers in future rates. In addition, we record regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other transaction of net allowable costs be given to customers over future periods.

Determination probability of recovery requires significant judgment by management and may include, but is not limited to, consideration of:

- the nature of the event giving rise to the assessment;
- existing statutes and regulatory code;
- legal precedents;
- regulatory principles and analogous regulatory actions;
- testimony presented in regulatory hearings;
- proposed regulatory decisions;
- final regulatory orders;
- a commission-authorized mechanism established for the accumulation of costs;
- status of applications for rehearings or state court appeals;
- specific approval from a commission; and
- historical experience.

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.

SUMMARY OF REGULATORY BALANCING ACCOUNTS AT DECEMBER 31
(Dollars in millions)

	SDG&E 2015	SDG&E 2014
Current:		
Overcollected	$ (756)	$ (1,195)
Undercollected	1,063	1,906
Net current receivable (payable)	$ 307	$ 711

Over- and undercollected 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 (receivable) or refundable (payable) 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 the cost of fuel supply and certain operating and maintenance costs from amounts approved by the CPUC would increase volatility in utility earnings.

We provide additional information about regulatory matters in Notes 10, 11 and 12.

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 (LIABILITIES) AT DECEMBER 31
(Dollars in millions)

	2015	2014
Fixed-price contracts and other derivatives	$ 99	$ 76
Costs related to SONGS plant closure(1)	257	308
Costs related to wildfire litigation	362	373
Deferred taxes recoverable in rates	914	824
Pension and other postretirement benefit plan obligations	180	171
Removal obligations(2)	(1,629)	(1,557)
Unamortized loss on reacquired debt	12	12
Environmental costs	16	27
Legacy meters(1)	32	47
Sunrise Powerlink fire mitigation	117	116
Other	9	10
Total	$ 369	$ 407

(1) Regulatory assets earning a rate of return.
(2) Represents cumulative amounts collected in rates for future nonlegal asset removal costs.

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

	2015	2014
Current regulatory assets	$ 107	$ 54
Noncurrent regulatory assets	1,891	1,910
Noncurrent regulatory liabilities	(1,629)	(1,557)
Total	$ 369	$ 407

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 commodity and transportation contracts. The regulatory asset is increased/decreased based on changes in the fair market value of the contracts. It is also reduced as payments are made for commodities and services under these contracts.

- Regulatory assets arising from the San Onofre Nuclear Generating Station (SONGS) plant closure are associated with SDG&E's investment in SONGS as of the plant closure date and the cost of operations since Units 2 and 3 were taken offline, as we discuss further in Note 10.
- Regulatory assets arising from costs related to wildfire litigation are costs in excess of liability insurance coverage and amounts recovered from third parties, as we discuss in Note 11 under "SDG&E Matters – Wildfire Claims Cost Recovery" and Note 12 under "SDG&E – 2007 Wildfire Litigation."
- Deferred taxes recoverable in rates are based on current regulatory ratemaking and income tax laws. SDG&E, expects to recover net regulatory assets related to deferred income taxes over the lives of the assets that give rise to the accumulated deferred income tax liabilities. Regulatory assets include certain income tax benefits associated with flow-through repair allowance deductions, which we discuss further in "Joint Matters – CPUC General Rate Case (GRC) – 2016 General Rate Case (2016 GRC)" in Note 11.
- Regulatory assets/liabilities related to pension and other postretirement benefit obligations are offset by corresponding liabilities/assets and are being recovered in rates as the plans are funded.
- Regulatory assets related to unamortized losses on reacquired debt are recovered over the remaining amortization periods of the losses on reacquired debt. These periods range from 2 years to 12 years for SDG&E.
- 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.
- The regulatory asset related to the legacy meters removed from service and replaced under the Smart Meter Program is their undepreciated value. SDG&E is recovering this asset over a remaining 2-year period in rate base.
- The regulatory asset related to Sunrise Powerlink fire mitigation is offset by a corresponding liability for the funding of a trust to cover the mitigation costs. SDG&E expects to recover the regulatory asset in rates as the trust is funded over a remaining 54-year period. We discuss the trust further in Note 12.
- Amortization expense on regulatory assets for the years ended December 31, 2015, 2014 and 2013 was $60 million, $18 million and $26 million, respectively.

FAIR VALUE MEASUREMENTS

We apply recurring fair value measurements to certain assets and liabilities, primarily nuclear decommissioning and benefit plan trust assets and derivatives. "Fair value" is defined 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).

A fair value measurement reflects 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. Also, we consider an issuer's credit standing when measuring its liabilities at fair value.

We establish 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 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 listed equities, U.S. government treasury securities and exchange-traded derivatives.

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
- current market and contractual prices for the underlying instruments
- volatility factors
- 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 domestic corporate bonds, municipal bonds and other foreign bonds, primarily in the Nuclear Decommissioning Trusts and in our pension and postretirement benefit plans, and non-exchange-traded derivatives such as interest rate instruments and 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. Our Level 3 financial instruments relate to congestion revenue rights (CRRs) and fixed-price electricity positions 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 trade and other accounts and notes receivable, which include allowances for doubtful customer accounts and for other receivables. We show the changes in these allowances in the table below:

COLLECTION ALLOWANCES
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Allowances for collection of receivables at January 1	$ 7	$ 5	$ 6
Provisions for uncollectible accounts	7	7	4
Write-offs of uncollectible accounts	(5)	(5)	(5)
Allowances for collection of receivables at December 31	$ 9	$ 7	$ 5

We evaluate accounts receivable collectability using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness, economic conditions and specific events, such as bankruptcies. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables, and historical and industry trends.

We write off accounts receivable in the period in which we deem the receivable to be uncollectible. We record recoveries of accounts receivable previously written off when it is known that they will be received.

INVENTORIES

We value 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 are generally valued at the lower of average cost or net realizable value.

The components of inventories by segment are as follows:

INVENTORY BALANCES AT DECEMBER 31
(Dollars in millions)

	Natural gas		Materials and supplies		Total	
	2015	2014	2015	2014	2015	2014
	$ 6	$ 8	$ 66	$ 62	$ 72	$ 70

INCOME TAXES

Income tax expense includes current and deferred income taxes from operations during the year. We record deferred income taxes for temporary differences between the book and the tax basis of assets and liabilities. Investment tax credits from prior years are amortized to income over the estimated service lives of the properties as required by the CPUC.

We 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.

When there are uncertainties related to potential income tax benefits, in order to qualify for recognition, the position we take has to have at least a “more likely than not” chance of being sustained (based on the position’s technical merits) upon challenge by the respective authorities. The term “more likely than not” means a likelihood of more than 50 percent. Otherwise, we may not recognize any of the potential tax benefit associated with the position. We recognize a benefit for a tax position that meets the “more likely than not” criterion at the largest amount of tax benefit that is greater than 50 percent likely of being realized upon its effective resolution.

Unrecognized tax benefits involve management’s judgment regarding the likelihood of the benefit being sustained. The final resolution of uncertain tax positions could result in adjustments to recorded amounts and may affect our effective tax rate.

We provide additional information about income taxes in Note 4.

GREENHOUSE GAS (GHG) ALLOWANCES

SDG&E is required by California Assembly Bill 32 to acquire GHG allowances for every metric ton of carbon dioxide equivalent emitted into the atmosphere during electric generation and natural gas transportation. We record GHG allowances at the lower of weighted average cost or market, and include them in Other Current Assets and Sundry on the Balance Sheet based on the dates that they are required to be surrendered. We measure the compliance obligation, which is based on emissions, at the carrying value of allowances held plus the fair value of additional allowances necessary to satisfy the obligation. We include the obligation in Other Current Liabilities and Deferred Credits and Other on the Balance Sheet based on the dates that the allowances will be surrendered. We remove the assets and liabilities from the balance sheet as the allowances are surrendered.

We balance costs and revenues associated with the GHG program through Regulatory Balancing Accounts on the Balance Sheet.

RENEWABLE ENERGY CERTIFICATES

Renewable energy certificates (RECs) represent property rights established by governmental agencies for the environmental, social, and other nonpower qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source in certain markets.

Retail sellers of electricity obtain RECs through renewable power purchase agreements, internal generation or separate purchases in the market to comply with renewable portfolio standards established by the governmental agencies. RECs provide documentation for the generation of a unit of renewable energy that is used to verify compliance with renewable portfolio standards. The cost of RECs at SDG&E is recorded in Cost of Electric Fuel and Purchased Power, which is recoverable in rates, on the Statement of Operations.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment primarily represents the buildings, equipment and other facilities used to provide natural gas and electric utility services. It also reflects projects includes in construction work in progress.

Our plant costs include

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

In addition, the cost of utility plant includes AFUDC. We discuss AFUDC below. The cost of non-utility plant includes capitalized interest.

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

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

	Property, plant and equipment at December 31,		Depreciation rates for years ended December 31,		
	2015	2014	2015	2014	2013
Natural gas operations	$ 1,642	$ 1,535	2.52 %	2.72 %	2.35 %
Electric distribution	6,151	5,795	3.79	3.79	3.36
Electric transmission(1)	4,870	4,525	2.62	2.59	2.58
Electric generation(2)	1,326	1,304	3.89	3.86	3.76
Other electric(3)	981	851	5.73	7.09	7.58
Construction work in progress(1)	923	910	NA	NA	NA
Total	$ 15,893	$ 14,920			

(1) At December 31, 2015, includes $374 million in electric transmission assets and $25 million in construction work in progress related to SDG&E's 91-percent interest in the Southwest Powerlink (SWPL) transmission line, jointly owned by SDG&E with other utilities. 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 its share of the project and participates in decisions concerning operations and capital expenditures.
(2) Includes capital lease assets of $258 million and $243 million at December 31, 2015 and 2014, respectively, primarily related to variable interest entities of which SDG&E is not the primary beneficiary.
(3) Includes capital lease assets of $20 million and $19 million at December 31, 2015 and 2014, respectively.

Depreciation expense is based on the straight-line method over the useful lives of the assets or a shorter period prescribed by the CPUC. Depreciation expense is computed using the straight-line method over the asset’s estimated original composite useful life, the CPUC-prescribed period or the remaining term of the site leases, whichever is shortest. Depreciation expense on property, plant and equipment for SDG&E for the years ended December 31, 2015, 2014 and 2013 was $578 million, $503 million and $466 million, respectively.

Accumulated depreciation on our Balance Sheet is as follows:

ACCUMULATED DEPRECIATION
(Dollars in millions)

	December 31, 2015	December 31, 2014
Accumulated depreciation:		
Electric(1)	$ 3,330	$ 3,044
Natural gas	690	668
Total SDG&E	$ 4,020	$ 3,712

(1) Includes accumulated depreciation for assets under capital lease of $34 million and $28 million at December 31, 2015 and 2014, respectively. Includes $224 million at December 31, 2015 related to SDG&E's 91-percent interest in the SWPL transmission line, jointly owned by SDG&E and other utilities.

We finance our construction projects with borrowed funds and equity funds. The CPUC and the FERC allow the recovery of the cost of these funds by the capitalization of AFUDC, calculated using rates authorized by the CPUC and the FERC, as a cost component of property, plant and equipment. We earn a return on the capitalized AFUDC after the utility property is placed in service and recover the AFUDC from our customers over the expected useful lives of the assets.

CAPITALIZED FINANCING COSTS
(Dollars in millions)

	Years ended December 31, 2015	2014	2013
AFUDC related to debt	$ 14	$ 15	$ 16
AFUDC related to equity	37	37	39
Total	$ 51	$ 52	$ 55

LONG-LIVED ASSETS

We test long-lived assets for recoverability whenever events or changes in circumstances have occurred that may affect the recoverability or the estimated useful lives of long-lived assets. Long-lived assets include intangible assets subject to amortization, but do not include investments in unconsolidated subsidiaries. Events or changes in circumstances that indicate that the carrying amount of a long-lived asset may not be recoverable may include

- significant decreases in the market price of an asset
- a significant adverse change in the extent or manner in which we use an asset or in its physical condition
- a significant adverse change in legal or regulatory factors or in the business climate that could affect the value of an asset
- a current period operating or cash flow loss combined with a history of operating or cash flow losses or a projection of continuing losses associated with the use of a long-lived asset
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life

A long-lived asset is impaired when the estimated future undiscounted cash flows are less than the carrying amount of the asset. If that comparison indicates that the asset’s carrying value may not be recoverable, the impairment is measured based on the difference between the carrying amount and the fair value of the asset. This evaluation is performed at the lowest level for which separately identifiable cash flows exist.

ASSET RETIREMENT OBLIGATIONS

For tangible long-lived assets, we record asset retirement obligations 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 also record a liability if a legal obligation to perform an asset retirement exists and can be reasonably estimated, but performance is conditional upon a future event. We record the estimated retirement cost over the life of the related asset by depreciating the asset retirement cost (measured as the present value of the obligation at the time of the asset's acquisition), and accreting the obligation until the liability is settled. Rate-regulated entities record regulatory assets or liabilities as a result of the timing difference between the recognition of costs in accordance with U.S. GAAP and costs recovered through the rate-making process.

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

- fuel and storage tanks
- natural gas distribution systems
- 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
- power generation plant (natural gas)

The changes in asset retirement obligations are as follows:

CHANGES IN ASSET RETIREMENT OBLIGATIONS
(Dollars in millions)

	2015	2014
Balance as of January 1(1)	$ 871	$ 911
Accretion expense	40	43
Liabilities incurred	-	-
Reclassification(2)	-	-
Payments(3)	(79)	(29)
Net revisions, other(4)	(6)	(54)
Balance at December 31(1)	$ 826	$ 871

(1) The current portions of the obligations are included in Other Current Liabilities on the Balance Sheet.
(2) Reclassification to liability held for sale - asset retirement obligation which is included in Other Current Liabilities on the Balance Sheet at December 31, 2014.
(3) The increased payments are for the decommissioning of San Onofre Nuclear Generating Station Units 2 and 3, which we discuss in Note 10.
(4) The decrease in 2014 is due to revised estimates in an updated decommissioning cost study for the San Onofre Nuclear Generating Station, which we discuss in Note 10.

CONTINGENCIES

We accrue losses for the estimated impacts of various conditions, situations or circumstances involving uncertain outcomes. For loss contingencies, we accrue the loss if an event has occurred on or before the balance sheet date and:

- information available through the date we file our financial statements indicates it is probable that a loss has been incurred, given the likelihood of uncertain future events; and
- the amount of the loss can be reasonably estimated.

We do not accrue contingencies that might result in gains. We continuously assess contingencies for litigation claims, environmental remediation and other events.

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:

- changes in unamortized net actuarial gain or loss and prior service cost related to pension and other postretirement benefits plans
- unrealized gains or losses on available-for-sale securities
- certain hedging activities

The Statement of Comprehensive Income shows the changes in the components of other comprehensive income (loss) (OCI). The following tables present the changes in accumulated other comprehensive income (loss) (AOCI) by component and amounts reclassified out of AOCI to net income for the years ended December 31:

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) BY COMPONENT
(Dollars in millions)

	Pension and other postretirement benefits	Total accumulated other comprehensive income (loss)
Balance as of December 31, 2012	$ (11)	$ (11)
Amounts reclassified from accumulated other comprehensive income	2	2
Net other comprehensive income	2	2
Balance as of December 31, 2013	(9)	(9)
Other comprehensive loss before reclassifications	(5)	(5)
Amounts reclassified from accumulated other comprehensive income	2	2
Net other comprehensive loss	(3)	(3)
Balance as of December 31, 2014	(12)	(12)
Other comprehensive income before reclassifications	3	3
Amounts reclassified from accumulated other comprehensive income	1	1
Net other comprehensive income	4	4
Balance as of December 31, 2015	$ (8)	$ (8)

RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

Details about accumulated	Amounts reclassified from accumulated other	Affected line item

other comprehensive income (loss) components	comprehensive income (loss)			on Statement of Operations
	Years ended December 31,			
	2015	2014	2013	
Pension and other postretirement benefits:				
Net actuarial gain	$ -	$ -	$ 2	See note (1) below
Amortization of actuarial loss	1	3	1	See note (1) below
	-	(1)	(1)	Income Tax Expense
Net of income tax	$ 1	$ 2	$ 2	
Total reclassifications for the period, net of tax	$ 1	$ 2	$ 2	

(1) Amounts are included in the computation of net periodic benefit cost (see "Net Periodic Benefit Cost" in Note 5).

REVENUES

We generate revenues primarily from deliveries to their customers of electricity and natural gas and from related services. We record these revenues following the accrual method and recognize them upon delivery and performance. As described below, recorded revenues include those authorized by the CPUC to support our operations (“decoupled revenue”), as well as commodity costs that are passed through to core gas customers and electric customers:

- Decoupled revenue – The regulatory framework permits SDG&E to recover authorized revenue based on estimated annual demand forecasts approved in regular proceedings before the CPUC. Any difference between actual demand and the annual demand approved in the proceedings is recovered or refunded in authorized revenue in the subsequent year. This design, commonly known as “decoupling,” is intended to minimize any impact on earnings due to variability in volumetric demand for electricity and natural gas.
- Commodity costs – The regulatory framework authorizes SDG&E to recover the actual cost of natural gas procured and delivered to its core customers in rates substantially as incurred. Actual electricity procurement costs are recovered as power is delivered, or to the extent actual amounts vary from forecasts, generally recovered or refunded within the subsequent year. SDG&E also record revenue from CPUC-approved incentive awards, some of which require approval by the CPUC prior to being recognized. We provide additional discussion on utility incentive mechanisms in Note 11.

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, consisting primarily of personnel costs, purchased materials and services, litigation expense and rent.

TRANSACTIONS WITH AFFILIATES

Amounts due from and to unconslidated affiliates at SDG&E are as follows:

AMOUNTS DUE FROM (TO) UNCONSOLIDATED AFFILIATES
(Dollars in millions)

December 31,

	2015	2014
Total due from various unconsolidated affiliates - current	$ 1	$ 1
Sempra Energy	$ (34)	$ (17)
SoCalGas	(13)	(4)
Affiliate	(8)	-
Total due to unconsolidated affiliates - current	$ (55)	$ (21)
Income taxes due from Sempra Energy(1)	$ 28	$ 16

(1) SDG&E is included in the consolidated income tax return of Sempra Energy and is allocated income tax expense from Sempra Energy in an amount equal to that which would result from the companies having always filed a separate return.

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

REVENUES FROM UNCONSOLIDATED AFFILIATES
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Revenues	$ 10	$ 13	$ 12

Cost of sales from unconsolidated affiliates at SDG&E is as follows:

COST OF SALES FROM UNCONSOLIDATED AFFILIATES
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Cost of Sales	$ 49	$ 17	$ 19

California Utilities

SempraEnergy, SDG&E and SoCalGas provide certain services to each other and are charged an allocable share of the cost of such services. Also, from time-to-time, SDG&E and SoCalGas may make short-term advances of surplus cash to Sempra Energy at interest rates based on one-month commercial paper rates.

SoCalGas provides natural gas transportation and storage services for SDG&E and charges SDG&E for such services monthly. SoCalGas records revenues and SDG&E records a corresponding amount to cost of sales.

SDG&E and SoCalGas charge one another, as well as other Sempra Energy affiliates, for shared asset depreciation. SoCalGas and SDG&E record revenues and the affiliates record corresponding amounts to operation and maintenance expense.

As we discuss in Note 11, the natural gas supply for SDG&E's and SoCalGas' core natural gas customers is purchased by SoCalGas as a combined procurement portfolio managed by SoCalGas. Core customers are primarily residential and small commercial and industrial customers. This core gas procurement function is considered a shared service, therefore revenues and costs related to SDG&E are not included in SoCalGas' Statement of Operations.

SDG&E has a 20-year contract for up to 155 MW of renewable power supplied from the Energía Sierra Juárez wind generation facility. Energía Sierra Juárez is a 50-percent owned and unconsolidated joint venture of Sempra Mexico that commenced operations in June 2015.

RESTRICTED NET ASSETS

The CPUC's regulation our capital structures limits the amounts available for dividends and loans to Sempra Energy. At December 31, 2015, Sempra Energy could have received combined loans and dividends of approximately $600 million, funded by long-term debt issuance, from SDG&E.

The payment and amount of future dividends by SDG&E is at the discretion of its boards of directors. The following restrictions limit the amount of retained earnings that may be paid as common stock dividends or loaned to Sempra Energy:

- The CPUC requires that our common equity ratio be no lower than one percentage point below the CPUC-authorized percentage of SDG&E's authorized capital structure. The authorized percentage at December 31, 2015 is 52 percent at SDG&E.
- The FERC requires SDG&E to maintain a common equity ratio of 30 percent or above.
- The California Utilities have a combined revolving credit line that requires each utility to maintain a ratio of consolidated indebtedness to consolidated capitalization (as defined in the agreement) of no more than 65 percent, as we discuss in Note 3.

Based on these restrictions, at December 31, 2015, SDG&E's restricted net assets were $4.6 billion, which could not be transferred to Sempra Energy.

OTHER INCOME, NET

Other Income, Net on the Statement of Operations consists of the following :

OTHER INCOME, NET
(Dollars in millions)

	Years ended December 31, 2015	2014	2013
Allowance for equity funds used during construction	$ 37	$ 37	$ 39
Regulatory interest, net(1)	3	6	4
Sundry, net	(4)	(3)	(3)
Total	$ 36	$ 40	$ 40

(1) Interest on regulatory balancing accounts.

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 an impact on or are unrelated to our financial condition, results of operations, cash flows or disclosures.

Accounting Standards Update (ASU) 2014-09, "Revenue from Contracts with Customers" (ASU 2014-09) and ASU 2015-14, "Revenue from Contracts with Customers: Deferral of the Effective Date" (ASU 2015-14): ASU 2014-09 provides accounting guidance for revenue from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers. The guidance also provides a model for the measurement and recognition of gains and losses on the sale of certain nonfinancial assets, such as property and equipment, including real estate. This guidance must be adopted using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach.

ASU 2015-14 defers the effective date of ASU 2014-09 by one year for all entities and permits early adoption on a limited basis. For public entities, ASU 2014-09 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted for fiscal years beginning after December 15, 2016, and is effective for interim periods in the year of adoption. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard or our transition method.

ASU 2015-03, "Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03) and ASU

2015-15, "Interest – Imputation of Interest: Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements" (ASU 2015-15): ASU 2015-03 provides guidance on the financial statement presentation of debt issuance costs and requires an entity to present debt issuance costs in the balance sheet as a direct deduction from the carrying amount of the related long-term debt liability. This guidance must be applied using a full retrospective approach for all periods presented in the period of adoption.

We retrospectively adopted ASU 2015-03 during our annual reporting period ended December 31, 2015, and the adoption did not affect our results of operations or cash flows. SDG&E Balance Sheet at December 31, 2014 reflect the reclassification of $36 million from Sundry to Long-Term Debt. We provide information about our long-term debt and related debt issuance costs in Note 3.

ASU 2015-15 clarifies ASU 2015-03 to provide additional guidance related to line-of-credit arrangements and states that the Securities and Exchange Commission staff would not object to an entity continuing to defer and present costs related to line-of-credit arrangements as an asset and subsequently amortizing the deferred costs ratably over the term of the line-of-credit arrangements, regardless of whether there are any outstanding borrowings on the line-of-credit arrangements. We adopted ASU 2015-15 for our annual reporting period ended December 31, 2015 and continue to include deferred costs related to our line-of-credit arrangements that are the subject of ASU 2015-15 in Sundry on SDG&E's Balance Sheet.

ASU 2015-17, "Income Taxes – Balance Sheet Classification of Deferred Taxes" (ASU 2015-17): ASU 2015-17 simplifies the financial statement presentation of deferred tax assets and liabilities and requires an entity to present deferred tax assets and liabilities as noncurrent on the balance sheet. This guidance may be applied prospectively or retrospectively.

We adopted ASU 2015-17 on a prospective basis for our annual reporting period ended December 31, 2015, and the adoption did not affect our results of operations or cash flows. Prior Balance Sheets of SDG&E were not retrospectively adjusted. We discuss deferred tax assets and liabilities in Note 4.

ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01): ASU 2016-01 primarily affects the accounting for equity investments (except those accounted for under the equity method of accounting), financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, it clarifies guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. Upon adoption, entities must record a cumulative-effect adjustment to the balance sheet as of the beginning of the first reporting period in which the standard is adopted. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard.

For public entities, ASU 2016-01 is effective for fiscal years beginning after December 15, 2017. We will adopt ASU 2016-01 on January 1, 2018 as required and do not expect it to materially affect our financial condition, results of operations or cash flows. We will make the required changes to our disclosures upon adoption.

ASU 2016-02, , "Leases" (ASU 2016-02): ASU 2016-02 requires entities to include substantially all leases on the balance sheet by requiring the recognition of right-of-use assets and lease liabilities for all leases. Entities may elect to not recognize leases with a maximum possible term of less than 12 months. For lessees, a lease is classified as finance or operating and the asset and liability are initially measured at the present value of the lease payments. For lessors, accounting for leases is largely unchanged from previous U.S. GAAP, other than certain changes to align lessor accounting to specific changes made to lessee accounting and ASU 2014-09. ASU 2016-02 also requires qualitative disclosures along with specific quantitative disclosures for both lessees and lessors.

For public entities, ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted, and is effective for interim periods in the year of adoption. The standard requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes optional practical expedients that may be elected, which would allow entities to continue to account for leases that commence before the effective date of the standard in accordance with previous U.S. GAAP unless the lease is modified, except for the lessee requirement to recognize right-of-use assets and lease liabilities for all operating leases at the reporting date. We are currently evaluating the effect of the standard on our ongoing financial reporting.

NOTE 3. DEBT AND CREDIT FACILITIES

LINES OF CREDIT

SDG&E and SoCalGas have a combined $1 billion, five-year syndicated revolving credit agreement, as amended and restated in October 2015, expiring in October 2020. JPMorgan Chase Bank, N.A. serves as administrative agent for the syndicate of 20 lenders, and no single lender has greater than a 7-percent share. The agreement permits each utility to individually borrow up to $750 million, subject to a combined limit of $1 billion 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 $250 million for both utilities. The amount of borrowings otherwise available under the facility is reduced by the amount of outstanding letters of credit. The amended credit facility restates and supersedes the California Utilities’ $877 million credit agreement that was to expire in 2017.

Borrowings bear interest at benchmark rates plus a margin that varies with the borrowing utility’s credit rating. The agreement requires each utility to maintain a ratio of total indebtedness to total capitalization (as defined in the agreement) of no more than 65 percent at the end of each quarter. At December 31, 2015, the California Utilities were in compliance with this and all other financial covenants under the credit facility.

Each utility'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, 2015, we had $168 million of commercial paper outstanding, supported by the facility. Available unused credit on the line at December 31, 2015 was $582 million.

WEIGHTED AVERAGE INTEREST RATES

The weighted average interest rate on the total short-term debt at SDG&E was 1.01 percent at December 31, 2015, and 0.27 percent at December 31, 2014.

LONG-TERM DEBT

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

LONG-TERM DEBT
(Dollars in millions)

	December 31,

		2015		2014(1)
First mortgage bonds (secured by plant assets):				
5.3% November 15, 2015	$	-	$	250
Bonds at variable rates (0.68% at December 31, 2015) March 9, 2017		140		-
1.65% July 1, 2018(2)		161		161
3% August 15, 2021		350		350
1.914% payable 2015 through February 2022		232		-
3.6% September 1, 2023		450		450
6% June 1, 2026		250		250
5% to 5.25% payable 2015 through December 2027(2)		105		150
5.875% January and February 2034(2)		176		176
5.35% May 15, 2035		250		250
6.125% September 15, 2037		250		250
4% May 1, 2039(2)		75		75
6% June 1, 2039		300		300
5.35% May 15, 2040		250		250
4.5% August 15, 2040		500		500
3.95% November 15, 2041		250		250
4.3% April 1, 2042		250		250
	$	3,989	$	3,912
Other long-term debt (unsecured unless otherwise noted):				
5.3% Notes July 1, 2021(2)(3)		-		39
5.5% Notes December 1, 2021(2)(3)		-		60
4.9% Notes March 1, 2023(2)(3)		-		25
366-day commercial paper borrowings May 2015, classified as long-term debt (0.40% weighted average at December 31, 2014)		-		100
Capital lease obligations: (4)				
Purchased-power agreements		243		233
Other		1		1
	$	244	$	458
		4,233		4,370
Current portion of long-term debt		(40)		(355)
Unamortized discount on long-term debt		(10)		(11)
Unamortized long-term debt issuance costs		(33)		(36)
Total SDG&E	$	4,150	$	3,968

(1) As adjusted for the retrospective adoption of ASU 2015-03.
(2) Callable long-term debt not subject to make-whole provisions.
(3) Early redemption in 2015.
(4) Excludes OMEC capital lease

MATURITIES OF LONG-TERM DEBT(1)
(Dollars in millions)

		SDG&E
2016	$	36
2017		176
2018		197
2019		35
2020		36
Thereafter		3,509
Total	$	3,989

(1) Excludes capital lease obligations.

There were no unsecured long-term obligations at SDG&E.

CALLABLE LONG-TERM DEBT

At the option of SDG&E, certain debt at December 31, 2015 is callable subject to premiums:

CALLABLE LONG-TERM DEBT
(Dollars in millions)

Not subject to make-whole provisions	$	517
Subject to make-whole provisions		3,472

FIRST MORTGAGE BONDS

We issue first mortgage bonds secured by a lien on utility plant. We may issue additional first mortgage bonds if in 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 $4.1 billion of first mortgage bonds at December 31, 2015.

In March 2015, SDG&E publicly offered and sold $140 million of first mortgage bonds maturing in 2017 at a variable rate of three-month LIBOR plus 0.20 percent (0.68 percent at December 31, 2015) and $250 million of 1.914-percent amortizing first mortgage bonds maturing in 2022. SDG&E used the proceeds from the offering to repay outstanding commercial paper and for other general corporate purposes.

OTHER LONG-TERM DEBT

In August 2015, we redeemed, prior to maturity, certain outstanding long-term debt instruments with a total principal amount of $169 million. The coupon rates of these instruments ranged from 4.9 percent to 5.5 percent, with maturities ranging from 2021 to 2027.

NOTE 4. INCOME TAXES

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

RECONCILIATION OF FEDERAL INCOME TAX RATES TO EFFECTIVE INCOME TAX RATES

	Years ended December 31,		
	2015	2014	2013
U.S. federal statutory income tax rate	35 %	35 %	35 %
State income taxes, net of federal income tax benefit	5	5	3
Depreciation	4	4	5
SONGS tax regulatory asset write-off	-	2	-
Repairs expenditures	(4)	(4)	(4)
Self-developed software expenditures	(3)	(3)	(3)
Allowance for equity funds used during construction	(2)	(2)	(2)
Resolution of prior years' income tax items	(2)	(2)	(1)
Other, net	-	-	(1)
Effective income tax rate	33 %	35 %	32 %

The effective income tax rates were impacted in 2014 by a $17 million charge to reduce certain tax regulatory assets attributed to our investment in SONGS that we discuss in Note 10. This charge is included in "Resolution of Prior Years' Income Tax Items" in the table above.

Utility repairs expenditures significantly affecting the effective income tax rates for us in 2015, 2014 and 2013 are due to a change in 2012 in the income tax treatment of certain repairs that are capitalized for financial statement purposes. The change in income tax treatment of certain repairs for electric transmission and distribution assets was made pursuant to an Internal Revenue Service (IRS) Revenue Procedure providing a safe harbor for deducting certain repairs expenditures from taxable income when incurred for tax years beginning on or after January 1, 2011.

The CPUC requires flow-through rate-making treatment for the current income tax benefit or expense arising from certain property-related and other temporary differences between the treatment for financial reporting and income tax, which will reverse over time. Under the regulatory accounting treatment required for these flow-through temporary differences, deferred income tax assets and liabilities are not recorded to deferred income tax expense, but rather to a regulatory asset or liability, which impacts the current effective income tax rate. As a result, changes in the relative size of these items compared to pretax income, from period to period, can cause variations in the effective income tax rate. The following items are subject to flow-through treatment:

- repairs expenditures related to a certain portion of utility plant fixed assets
- the equity portion of AFUDC
- a portion of the cost of removal of utility plant assets
- utility self-developed software expenditures
- depreciation on a certain portion of utility plant assets
- state income taxes

The components of income tax expenses are as follows:

INCOME TAX EXPENSE (BENEFIT)
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Current:			
U.S. federal	$ 12	$ (5)	$ 9
U.S. state	77	52	11
Total	89	47	20
Deferred:			
U.S. federal	233	220	149
U.S. state	(35)	5	24
Total	198	225	173
Deferred investment tax credits	(3)	(2)	(2)
Total income tax expense	$ 284	$ 270	$ 191

We show the components of deferred income taxes at December 31 in the table below:

DEFERRED INCOME TAXES
(Dollars in millions)

	December 31,	
	2015	2014
Deferred income tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 2,392	$ 2,181
Regulatory balancing accounts	234	441
Property taxes	42	39
Other	5	5
Total deferred income tax liabilities	$ 2,673	$ 2,666
Deferred income tax assets:		
Net operating losses	-	297
Postretirement benefits	90	85
Compensation-related items	11	8
State income taxes	46	27
Litigation and other accruals not yet deductible	36	39
Other	18	36
Total deferred income tax assets	201	492
Net deferred income tax liability	$ 2,472	$ 2,174

Following is a summary of unrecognized income tax benefits:

SUMMARY OF UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Total	$ 20	$ 14	$ 17
Of the total, amounts related to tax positions that, if recognized in future years, would			
decrease the effective tax rate(1)	$ (16)	$ (11)	$ (14)
increase the effective tax rate(1)	11	6	11

(1) Includes temporary book and tax differences that are treated as flow-through for ratemaking purposes, as discussed above.

Following is a reconciliation of the changes in unrecognized income tax benefits for the years ended December 31:

RECONCILIATION OF UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	2015	2014	2013
Balance as of January 1	$ 14	$ 17	$ 12
Increase in prior period tax positions	5	2	7
Decrease in prior period tax positions	-	-	(4)
Increase in current period tax positions	2	-	2
Settlements with taxing authorities	(1)	(5)	-
Balance as of December 31	$ 20	$ 14	$ 17

It is reasonably possible that within the next 12 months, unrecognized income tax benefits could decrease due to the following:

POSSIBLE DECREASES IN UNRECOGNIZED INCOME TAX BENEFITS WITHIN 12 MONTHS
(Dollars in millions)

	At December 31,		
	2015	2014	2013
Expiration of statutes of limitations on tax assessments	$ (1)	$ -	$ -
Potential resolution of audit issues with various U.S. federal, state and local taxing authorities	(8)	(9)	(14)
	$ (9)	$ (9)	$ (14)

Amounts accrued for interest and penalties associated with unrecognized income tax benefits are included in income tax expense on the Statement of Operations. We summarize the amounts accrued at December 31 on the Balance Sheet for interest and penalties associated with unrecognized income tax benefits and the related expense in the table below.

INTEREST AND PENALTIES ASSOCIATED WITH UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	Interest and penalties			Accrued interest and penalties	
	Years ended December 31,			December 31,	
	2015	2014	2013	2015	2014
Interest income	$ -	$ (1)	$ -	$ -	$ -

Penalties accrued and expensed in all periods presented were zero or negligible.

INCOME TAX AUDITS

We are subject to U.S. federal income tax as well as income tax of state jurisdictions. We remain subject to examination for U.S. federal tax years after 2010 and by state tax jurisdictions for tax years after 2008.

NOTE 5. EMPLOYEE BENEFIT PLANS

We are required by applicable U.S. GAAP to:

- 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 pension and other postretirement benefit plans in the year in which the changes occur. Generally, those changes are reported in other comprehensive income and as a separate component of shareholders' equity.

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

Sempra Energy has funded and unfunded noncontributory traditional defined benefit and cash balance plans, including separate plans for SDG&E, which collectively cover all eligible employees, including members of the Sempra Energy board of directors who were participants in a predecessor plan on or before June 1, 1998. Pension benefits under the traditional defined benefit plans are based on service and final average earnings, while the cash balance plans provide benefits using a career average earnings methodology.

Sempra Energy also has other postretirement benefit plans (PBOP), including separate plans for SDG&E, which collectively cover all employees. 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
- rate of compensation increases
- termination and retirement rates
- utilization of postretirement welfare benefits
- payout elections (lump sum or annuity)
- lump sum interest rates

We review these assumptions on an annual basis and update them as 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.

RABBI TRUST

In support of its Supplemental Executive Retirement, Cash Balance Restoration and Deferred Compensation Plans, Sempra Energy maintains dedicated assets, including a Rabbi Trust and investments in life insurance contracts, which totaled $464 million and $512 million at December 31, 2015 and 2014, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Benefit Plan Amendments Affecting 2015

Effective January 1, 2016, the point of service medical benefit provided to retirees under the age of 65, except the represented retirees, is no longer provided by the PBOP plans of the respective companies. This change resulted in a decrease in other postretirement benefit obligations by a negligible amount.

Benefit Plan Amendments Affecting 2014

Effective January 1, 2014, a new high deductible medical benefit was provided to all retirees under the age of 65. This benefit replaced a previous benefit provided by our plans. These changes resulted in an increase in other postretirement benefit obligations by a negligible amount.

Special Termination Benefits Affecting 2014

At SDG&E in 2014, all nonrepresented employees age 62 with 5 years of service and all other nonrepresented employees age 55 with 10 years of service that retired under the Voluntary Retirement Enhancement Program offered in that year received an additional postretirement health benefit in the form of a $50,000 Health Reimbursement Account (HRA). In accordance with U.S. GAAP, we elected to treat the benefit obligation attributable to the HRA as special termination benefits. This resulted in increases to the recorded liability for other postretirement benefits of approximately $5 million in 2014.

Benefit Obligations and Assets

The following table provides a reconciliation of the changes in the plan's projected benefit obligations and the fair value of assets during 2015 and 2014, and a statement of the funded status at December 31, 2015 and 2014:

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

	Pension benefits		Other postretirement benefits	
	2015	2014	2015	2014
CHANGE IN PROJECTED BENEFIT OBLIGATION				
Net obligation at January 1	$ 1,011	$ 939	$ 200	$ 171
Service cost	29	30	7	7
Interest cost	39	43	8	9
Contributions from plan participants	-	-	7	6
Actuarial (gain) loss	(52)	101	(43)	15
Benefit payments	(56)	(25)	(14)	(13)
Special termination benefits	-	-	-	5
Settlements	-	(87)	-	-
Transfer of liability (to) from other plans	(6)	10	-	-
Net obligation at December 31	$ 965	$ 1,011	$ 165	$ 200
CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	828	819	164	146
Actual return on plan assets	(24)	63	(3)	11
Employer contributions	2	56	7	14
Contributions from plan participants	-	-	7	6
Benefit payments	(56)	(25)	(14)	(13)
Settlements	-	(87)	-	-
Transfer of assets from other plans	2	2	-	-
Fair value of plan assets at December 31	752	828	161	164
Funded status at December 31	$ (213)	$ (183)	$ (4)	$ (36)
Net recorded liability at December 31	$ (213)	$ (183)	$ (4)	$ (36)

New mortality table studies were released by the Society of Actuaries during 2014 that significantly increased life expectancy assumptions, and during 2015 that consisted of a new mortality improvement projection scale. We have incorporated these assumptions, adjusted for the company's actual mortality experience, in our calculations for each of those years.

In 2015, the actuarial gains for pension plans were primarily due to:
- an increase in weighted-average discount rates;
- updated mortality rates;
- a change in the rate used to convert annuity benefits to lump sums; and
- the impact of updated census data; **offset by**
- changes in anticipated retirement rates.

In 2015, the actuarial gains for other postretirement benefit plans were primarily due to:
- the impact of updated census data;
- changes in termination and retirement rates;
- an increase in weighted-average discount rates;
- a decrease in the actual versus expected 2016 claims costs; and
- updated mortality rates; **offset by**
- changes in health care cost trend rates.

In 2014, the actuarial losses for pension plans were primarily due to:
- a decrease in weighted-average discount rates; and
- updated mortality rates; **offset by**
- a decrease in the cash balance interest crediting rate.

In 2014, the actuarial losses for other postretirement benefit plans were primarily due to:
- a decrease in weighted-average discount rates;
- updated mortality rates; and
- the impact of updated census data; **offset by**
- a decrease in anticipated retiree and spousal participation rates.

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 investment gains and losses, which we defer and recognize in pension and other postretirement benefit costs over a period of years. SDG&E does not use the asset smoothing method, but rather recognizes realized and unrealized investment gains and losses during the current year.

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.

We recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets or liabilities, respectively; unrecognized changes in these assets and/or liabilities are normally recorded in Accumulated Other Comprehensive Income (Loss) on the balance sheet. We record regulatory assets and liabilities that offset the funded pension and other postretirement plans' assets or liabilities, as these costs are expected to be recovered in future utility rates based on agreements with regulatory agencies.

We record annual pension and other postretirement net periodic benefit costs equal to the contributions to their plans as authorized by the CPUC. The annual contributions to the pension plans are limited to a minimum required funding amount as determined by the IRS. The annual contributions to the other postretirement plans are equal to the lesser of the maximum tax deductible amount or the net periodic cost calculated in accordance with U.S. GAAP for pension and other postretirement benefit plans. Any differences between booked net periodic benefit cost and amounts contributed to the pension and other postretirement plans are disclosed as regulatory adjustments in accordance with U.S. GAAP for rate-regulated entities.

The net (liability) asset is included in the following categories on the Balance Sheet at December 31:

PENSION AND OTHER POSTRETIREMENT BENEFIT OBLIGATIONS, NET OF PLAN ASSETS AT DECEMBER 31
(Dollars in millions)

	Pension benefits		Other postretirement benefits	
	2015	2014	2015	2014
Current liabilities	$ (5)	$ (3)	$ -	$ -
Noncurrent liabilities	(208)	(180)	(4)	(36)
Net recorded liability	$ (213)	$ (183)	$ (4)	$ (36)

Amounts recorded in accumulated other comprehensive income (loss) at December 31, 2015 and 2014, net of income tax effects and amounts recorded as regulatory assets, are as follows:

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

	Pension benefits	
	2015	2014
Net actuarial loss	$ (8)	$ (13)
Prior service credit	-	1
Total	$ (8)	$ (12)

The accumulated benefit obligation for defined benefit pension plans at December 31, 2015 and 2014 was as follows:

ACCUMULATED BENEFIT OBLIGATION
(Dollars in millions)

	2015	2014
Accumulated benefit obligation	$ 939	$ 978

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

OBLIGATIONS OF FUNDED PENSION PLANS
(Dollars in millions)

	2015	2014
Projected benefit obligation	$ 927	$ 964
Accumulated benefit obligation	906	937
Fair value of plan assets	752	828

Net Periodic Benefit Cost

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

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

	Pension benefits			Other postretirement benefits		
	2015	2014	2013	2015	2014	2013

NET PERIODIC BENEFIT COST						
Service cost	$ 29	$ 30	$ 32	$ 7	$ 7	$ 8
Interest cost	39	43	41	8	9	8
Expected return on assets	(54)	(55)	(52)	(11)	(10)	(8)
Amortization of:						
Prior service cost	8	2	2	3	2	4
Actuarial loss	2	4	14	-	-	-
Settlement charge	-	19	1	-	-	-
Special termination benefits	-	-	-	-	5	2
Regulatory adjustment	(20)	12	14	-	1	-
Total net periodic benefit cost	4	55	52	7	14	14
CHANGES IN PLAN ASSETS AND BENEFIT OBLIGATIONS RECOGNIZED IN OTHER COMPREHENSIVE INCOME (LOSS)						
Net (gain) loss	(6)	8	(2)	-	-	-
Amortization of actuarial loss	(1)	(3)	(1)	-	-	-
Total recognized in other comprehensive (loss) income	(7)	5	(3)	-	-	-
Total recognized in net periodic benefit cost and other comprehensive (loss) income	$ (3)	$ 60	$ 49	$ 7	$ 14	$ 14

The estimated net loss for the pension and other postretirement benefit plans that will be amortized from accumulated other comprehensive income (loss) into net periodic benefit cost in 2016 is $1 million for SDG&E. Negligible amounts of estimated prior service cost that will be similarly amortized in 2016.

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

We develop the discount rate assumption based on the results of a third party modeling tool that develops the discount rate by matching each plan's expected cash flows to interest rates and expected maturity values of individually selected bonds in a hypothetical portfolio. The model controls the level of accumulated surplus that may result from the selection of bonds based solely on their premium yields by limiting the number of years to look back for selection to 3 years for pre-30-year and 6 years for post-30-year benefit payments. Additionally, the model ensures that an adequate number of bonds are selected in the portfolio by limiting the amount of the plan's benefit payments that can be met by a single bond to 7.5 percent.

We selected individual bonds from a universe of Bloomberg AA-rated bonds which:

- have an outstanding issue of at least $50 million;
- are non-callable (or callable with make-whole provisions);
- exclude collateralized bonds; and
- exclude the top and bottom 10 percent of yields to avoid relying on bonds which might be mispriced or misgraded.

This selection methodology also mitigates the impact of market volatility on the portfolio by excluding bonds with the following characteristics:

- The issuer is on review for downgrade by a major rating agency if the downgrade would eliminate the issuer from the portfolio.
- Recent events have caused significant price volatility to which rating agencies have not reacted.
- Lack of liquidity is causing price quotes to vary significantly from broker to broker.

We believe that this bond selection approach provides the best estimate of discount rates to estimate settlement values for our plans' benefit obligations as required by applicable U.S. GAAP.

Long-term return on assets is based on the weighted-average of the plans' investment allocations as of the measurement date and the expected returns for those asset types.

We amortize prior service cost using straight line amortizations over average future service (or average expected lifetime for plans where participants are substantially inactive employees), which is an alternative method allowed under GAAP.

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

WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE BENEFIT OBLIGATION AT DECEMBER 31

	Pension benefits		Other postretirement benefits	
	2015	2014	2015	2014
Discount rate	4.35 %	4.00 %	4.50 %	4.15 %
Rate of compensation increase	2.00-10.00	3.50-10.00	2.00-10.00	3.50-10.00

WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COST FOR YEARS ENDED DECEMBER 31

	Pension benefits			Other postretirement benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	4.00 %	4.69 %	3.94 %	4.15 %	5.00 %	4.10 %
Expected return on plan assets	7.00	7.00	7.00	6.91	6.88	6.81
Rate of compensation increase	2.00-10.00	3.50-10.00	3.50-9.50	2.00-10.00	3.50-10.00	N/A

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:

ASSUMED HEALTH CARE COST TREND RATES AT DECEMBER 31

	Other postretirement benefit plans					
	Pre-65 retirees			Retirees aged 65 years and older		
	2015	2014	2013	2015	2014	2013
Health care cost trend rate assumed for next year	8.10 %	7.75 %	8.25 %	5.50 %	5.25 %	5.50 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	5.00 %	5.00 %	5.00 %	4.50 %	4.50 %	4.50 %
Year the rate reaches the ultimate trend	2022	2020	2020	2022	2020	2020

A one-percent change in assumed health care cost trend rates would have had the following effects in 2015:

EFFECT OF ONE-PERCENT CHANGE IN ASSUMED HEALTH CARE COST TREND RATES
(Dollars in millions)

	1% increase	1% decrease
Effect on total of service and interest		

cost components of net periodic postretirement health care benefit cost	$	1	$	(1)
Effect on the health care component of the accumulated other postretirement benefit obligations	$	5	$	(4)

Plan Assets

Investment Allocation Strategy for Sempra Energy's Pension Master Trust

Sempra Energy's pension master trust holds the investments for the pension and other postretirement benefit plans. We maintain additional trusts as we discuss below for certain of the California Utilities' other postretirement benefit plans. Other than through indexing strategies, the trusts do not invest in securities of Sempra Energy.

The current asset allocation objective for the pension master trust is to protect the funded status of the plans while generating sufficient returns to cover future benefit payments and accruals. We assess the portfolio performance by comparing actual returns with relevant benchmarks. Currently, the pension plans' target asset allocations are

- 38 percent domestic equity
- 26 percent international equity
- 18 percent long credit
- 5 percent global high yield credit
- 5 percent real assets
- 4 percent STRIPS
- 4 percent long government

The asset allocation of the plans is reviewed by our Plan Funding Committee and our Pension and Benefits Investment Committee (the Committees) on a regular basis. When evaluating strategic asset allocations, the Committees consider many variables, including:

- long-term cost
- variability and level of contributions
- funded status
- a range of expected outcomes over varying confidence levels

We maintain allocations at strategic levels with reasonable bands of variance.

In accordance with the Sempra Energy pension investment guidelines, derivative financial instruments may be used by the pension master trust's equity and fixed income portfolio investment managers to equitize cash, hedge certain exposures, and as substitutes for certain types of fixed income securities.

Rate or Return Assumption

The expected return on assets in our pension and other postretirement benefit plans is based on the weighted-average of the plans' investment allocations to specific asset classes as of the measurement date. We arrive at a 7 percent expected return on assets by considering both the historical and forecasted long-term rates of return on those asset classes. We expect a return of between 7 percent and 9 percent on return-seeking assets and between 3 percent and 5 percent for risk-mitigating assets. Certain trusts that hold assets for our other postretirement benefit plans are subject to taxation, which impacts the expected after-tax return on assets in these plans.

Concentration of Risk

Plan assets are fully diversified across global equity and bond markets, and other than what is indicated by the target asset allocations, contain no concentration of risk in any one economic, industry, maturity or geographic sector.

Investment Strategy for SDG&E Other Postretirement Benefit Plans

SDG&E's other postretirement benefit plans are funded by cash contributions from SDG&E and their current retirees. The assets of these plans are placed into the pension master trust and other Voluntary Employee Beneficiary Association (VEBA) trusts. The assets in the VEBA trusts are invested at an allocation similar to the pension master trust, with 70 percent invested in return-seeking and 30 percent invested in risk-mitigating assets. This allocation is periodically reviewed to ensure that plan assets are best positioned to meet plan obligations.

Fair Value of Pension and Other Postretirement Benefit Plan Assets

We classify the trusts for SDG&E’s other postretirement benefit plans into:

- Level 1, for securities valued using quoted prices from active markets for identical assets;
- Level 2, for securities not traded on an active market but for which observable market inputs are readily available; and
- Level 3, for securities and investments valued based on significant unobservable inputs. Investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following are descriptions of the valuation methods and assumptions we use to estimate the fair values of investments held by pension and other postretirement benefit plan trusts.

Equity Securities – Equity securities are valued using quoted prices listed on nationally recognized securities exchanges.

Fixed Income Securities – Certain fixed income securities are valued at the closing price reported in the active market in which the security is traded. Other fixed income securities are valued based on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar securities, the security is valued under a discounted cash flows approach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks. Certain high yield fixed-income securities are valued by applying a price adjustment to the bid side to calculate a mean and ask value. Adjustments can vary based on maturity, credit standing, and reported trade frequencies. The bid to ask spread is determined by the investment manager based on the review of the available market information.

Registered Investment Companies – Investments in mutual funds sponsored by a registered investment company are valued based on exchange listed prices for equity and certain fixed income securities or are valued under a discounted cash flows approach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks for the remaining fixed income securities.

Common/Collective Trusts – Investments in common/collective trust funds are valued based on the redemption price of units owned, which is based on the current fair value of the funds’ underlying assets.

Private Equity Funds – Investments in private equity funds do not trade in active markets. Fair value is determined by the fund managers, based on their review of the underlying investments as well as their utilization of discounted cash flows and other valuation models.

Venture Capital Funds – These funds consist of investments in private equities that are held by limited partnerships following various strategies, including venture capital and corporate finance. The partnerships generally have limited lives of 10 years, after which liquidating distributions will be received. Fair value is determined by attributing a proportionate share of net assets to an ownership interest in partners’ capital.

Real Estate Funds – Investments in real estate funds are valued based on the net asset value per share. Net asset value is based on the fair value of the underlying investments.

Derivative Financial Instruments – Forward currency contracts are valued at the prevailing forward exchange rate of the underlying currencies, and unrealized gain (loss) is recorded daily. Fixed income futures and options are marked to market daily. Equity index future contracts are valued at the last sales price quoted on the exchange on which they primarily trade.

The methods described are intended to produce a fair value calculation that is indicative of net realizable value or reflective of fair values. However, while management believes the valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

We provide more discussion of fair value measurements in Notes 1 and 8. The following tables set forth by level within the fair value hierarchy a summary of the investments in our pension and other postretirement benefit plan trusts measured at fair value on a recurring basis.

There were no transfers into or out of Level 1, Level 2 or Level 3 for SDG&E during the periods presented, nor any changes in the valuation techniques used in recurring fair value measurement.

The fair values of our pension plan assets by asset category are as follows:

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF PENSION PLANS
(Dollars in millions)

	Fair value at December 31, 2015			
	Level 1	Level 2	Level 3	Total
Equity securities:				
Domestic(1)	$ 269	$ -	$ -	$ 269
Foreign	163	-	-	163
Domestic preferred	-	2	-	2
Foreign preferred	1	-	-	1
Registered investment companies	38	-	-	38
Fixed income securities:				
U.S. Treasury securities	38	-	-	38
Domestic municipal bonds	-	9	-	9
Foreign government bonds	-	3	-	3
Domestic corporate bonds(2)	-	103	-	103
Foreign corporate bonds	-	30	-	30
Common/collective trusts(3)	-	94	-	94
Registered investment companies	-	2	-	2
Other investments(4)	-	-	1	1
Total investment assets(5)	$ 509	$ 243	$ 1	$ 753

(1) Investments in common stock of domestic corporations.
(2) Bonds of U.S. issuers from diverse industries, primarily investment-grade.
(3) Investments in common/collective trusts held in Sempra Energy's Pension Master Trust.
(4) Investments in venture capital and real estate funds, stated at net asset value, and derivative financial instruments.
(5) Excludes cash and cash equivalents of $4 million, accounts payable of $7 million and transfers receivable from other plans of $2 million at SDG&E.

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF PENSION PLANS
(Dollars in millions)

	Fair value at December 31, 2014			
	Level 1	Level 2	Level 3	Total
Equity securities:				

	Level 1	Level 2	Level 3	Total
Domestic(1)	$ 307	$ -	$ -	$ 307
Foreign	186	-	-	186
Domestic preferred	-	1	-	1
Foreign preferred	1	-	-	1
Registered investment companies	40	-	-	40
Fixed income securities:				
U.S. Treasury securities	38	-	-	38
Domestic municipal bonds	-	11	-	11
Foreign government bonds	-	12	-	12
Domestic corporate bonds(2)	-	117	-	117
Foreign corporate bonds	-	36	-	36
Common/collective trusts(3)	-	62	-	62
Registered investment companies	-	10	-	10
Other investments(4)	-	-	4	4
Total investment assets(5)	$ 572	$ 249	$ 4	$ 825

(1) Investments in common stock of domestic corporations include, on a combined basis at SDG&E, SoCalGas and Other Sempra Energy, 11,558 shares of Sempra Energy common stock at a value of $1 million.
(2) Bonds of U.S. issuers from diverse industries, primarily investment-grade.
(3) Investments in common/collective trusts held in Sempra Energy's Pension Master Trust.
(4) Investments in venture capital and real estate funds, stated at net asset value, and derivative financial instruments.
(5) Excludes cash and cash equivalents of $3 million at SDG&E.

The fair values by asset category of the other postretirement benefit plan assets held in the pension master trust and in the additional trusts for SDG&E's other postretirement benefit plan (PBOP plan trusts) are as follows:

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS
(Dollars in millions)

	Fair value at December 31, 2015			
	Level 1	Level 2	Level 3	Total
Equity securities:				
Domestic(1)	$ 39	$ -	$ -	$ 39
Foreign	24	-	-	24
Registered investment companies	41	-	-	41
Fixed income securities:				
U.S. Treasury securities	5	-	-	5
Domestic municipal bonds	-	3	-	3
Domestic corporate bonds(2)	-	15	-	15
Foreign corporate bonds	-	4	-	4
Common/collective trusts(3)	-	14	-	14
Registered investment companies	-	16	-	16
Total investment assets(4)	$ 109	$ 52	$ -	$ 161

(1) Investments in common stock of domestic corporations.
(2) Bonds of U.S. issuers from diverse industries, primarily investment-grade.
(3) Investments in common/collective trusts held in PBOP plan VEBA trusts and in the pension master trust.
(4) Excludes cash and cash equivalents of $1 million and accounts payable of $1 million held in SDG&E PBOP plan trusts.

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS
(Dollars in millions)

	Fair value at December 31, 2014			
	Level 1	Level 2	Level 3	Total

Equity securities:								
Domestic(1)	$	41	$	-	$	-	$	41
Foreign		25		-		-		25
Registered investment companies		43		-		-		43
Fixed income securities:								
U.S. Treasury securities		5		-		-		5
Domestic municipal bonds		-		3		-		3
Domestic corporate bonds(2)		-		16		-		16
Foreign government bonds		-		2		-		2
Foreign corporate bonds		-		5		-		5
Common/collective trusts(3)		-		8		-		8
Registered investment companies		-		16		-		16
Total investment assets	$	114	$	50	$	-	$	164

(1) Investments in common stock of domestic corporations include, on a combined basis at SDG&E, SoCalGas and Other Sempra Energy, 2,005 shares of Sempra Energy common stock at a value of $0.2 million.
(2) Bonds of U.S. issuers from diverse industries, primarily investment-grade.
(3) Investments in common/collective trusts held in PBOP plan VEBA trusts and in the pension master trust.

The investments of the pension master trust allocated to the pension and other postretirement benefit plans classified as Level 3 are private equity funds and represent a percentage of each plan's total allocated assets as follows at December 31:

LEVEL 3 INVESTMENT ASSETS
(Dollars in millions)

	Pension plans				Other postretirement benefit plans			
	Level 3 investment assets		% of total investment assets		Level 3 investment assets		% of total investment assets	
	2015	2014	2015	2014	2015	2014	2015	2014
SDG&E	$ 1	$ 4	- %	- %	$ -	$ -	- %	- %

The following table provides a reconciliation of changes in the fair value of investments classified as Level 3:

LEVEL 3 RECONCILIATIONS
(Dollars in millions)

PENSION PLANS		
Balance at January 1, 2014	$	6
Realized gains		1
Unrealized losses		(1)
Sales		(2)
Balance at December 31, 2014		4
Realized gains		1
Unrealized gains		-
Sales		(4)
Balance at December 31, 2015	$	1
OTHER POSTRETIREMENT BENEFIT PLANS		
Balance at January 1, 2014	$	1
Unrealized losses		(1)
Balance at December 31, 2014		-
Sales		-
Balance at December 31, 2015	$	-

Future Payments

We expect to contribute the following amounts to our pension and other postretirement benefit plans in 2016:

EXPECTED CONTRIBUTIONS
(Dollars in millions)

Pension plans	$	5
Other postretirement benefit plans		2

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

EXPECTED BENEFIT PAYMENTS
(Dollars in millions)

	Pension benefits	Other postretirement benefits
2016	$ 86	$ 8
2017	84	9
2018	82	10
2019	80	10
2020	77	10
2021-2025	$ 339	$ 54

SAVINGS PLAN

We offer trusteed savings plans to all employees. Participation in the plans is immediate for salary deferrals for all employees who are eligible upon completion of one year of service. Subject to plan provisions, employees may contribute from one percent to 50 percent of their eligible earnings, subject to annual IRS limits.

Through March 27, 2015, we made matching contributions for all employees after one year of the employee's completed service. Beginning March 28, 2015, Sempra Energy makes matching contributions for employees immediately as of the date of hire who continue to receive matching contributions after one year of the employee's completed service.

Also beginning March 28, 2015, employer contribution amounts for all employees are equal to 50 percent of the first 6 percent, plus 20 percent of the next 5 percent, of eligible earnings contributed by employees. Prior to that, employer contribution amounts for these employees were 50 percent of the first 6 percent of eligible earnings contributed by the employees and, if certain company goals were met, an additional amount related to incentive compensation payments.

Contributions to the savings plans were as follows:

CONTRIBUTIONS TO SAVINGS PLANS
(Dollars in millions)

	2015	2014	2013
SDG&E	$ 17	$ 15	$ 14

The market value of Sempra Energy common stock held by the savings plans was $1.1 billion and $1.4 billion at December 31, 2015 and 2014, respectively.

NOTE 6. 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.

In May 2013, shareholders approved the Sempra Energy 2013 Long-Term Incentive Plan. Upon approval, the remaining authorized shares from the Sempra Energy 2008 Long Term Incentive Plan and the 2008 Long Term Incentive Plan for EnergySouth, Inc. Employees and Other Eligible Individuals were applied to the number of shares authorized in the 2013 Plan.

At December 31, 2015, 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, in accordance with the terms of the grant, or upon eligibility for retirement. Options are subject to forfeiture or earlier expiration when an employee terminates employment.
- *Performance-Based Restricted Stock Units:* These restricted stock unit awards generally vest in Sempra Energy common stock at the end of three-year (for awards granted in 2015) or four-year performance periods based on Sempra Energy’s total return to shareholders relative to that of specified market indices or based on the compound annual growth rate of Sempra Energy’s earnings per common share (EPS). For awards granted in 2013 or earlier, if Sempra Energy’s total return to shareholders exceeds target levels, up to an additional 50 percent of the number of granted restricted stock units may be issued. For awards granted during or after 2014, up to an additional 100 percent of the granted restricted stock units may be issued if total return to shareholders or EPS growth exceeds target levels. If Sempra Energy’s total return to shareholders or EPS growth is below the target levels but above threshold performance levels, shares are subject to partial vesting on a pro rata basis. For awards granted in 2015 that vest based on Sempra Energy’s total return to shareholders, a modifier adds 20 percent to the award’s payout (as initially calculated based on total return to shareholders relative to that of specified market indices) for total shareholder return performance in the top quartile relative to historical benchmark data for Sempra Energy and reduces the award’s payout by 20 percent for performance in the bottom quartile. However, in no event will more than an additional 100 percent of the granted restricted stock units be issued. If performance falls within the second or third quartiles, the modifier is not triggered, and the payout is based solely on total return to shareholders relative to that of specified market indices. Also, vesting may be subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the applicable long-term incentive plan, or in accordance with severance pay agreements. Dividend equivalents on shares subject to 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.
- *Other Performance-Based Restricted Stock Units:* Restricted stock units were granted in 2014 and 2015 in connection with the creation of Cameron LNG JV. The 2014 awards vest to the extent that the Compensation Committee of Sempra Energy’s Board of Directors determines that the objectives of the joint venture are continuing to be achieved. These awards vest on the anniversary of the grant date over a period of either two or three years. The 2015 awards vest to the extent that the Compensation Committee of Sempra Energy’s Board of Directors determines that Sempra Energy has achieved positive cumulative net income for fiscal years 2015 through 2017 and Cameron LNG JV has commenced commercial operations of the first train. Vesting may be subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the applicable long-term incentive plan, or in accordance with severance pay agreements. Dividend equivalents on shares subject to 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.
- *Service-Based Restricted Stock Units:* Restricted stock units may also be service-based; these generally vest at the end of three-year (for awards granted in 2015) or four-year service periods. Vesting may be subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the

applicable long-term incentive plan, in accordance with severance pay agreements, or at the discretion of the Compensation Committee of Sempra Energy's Board of Directors. Dividend equivalents on shares subject to 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.

- *Restricted Stock:* Restricted stock awards are solely service-based and are generally exercisable at the end of four years of service. Vesting is subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the applicable long-term incentive plan, 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.

SHARE-BASED AWARDS AND COMPENSATION EXPENSE

We measure and recognize compensation expense for all share-based payment awards made to our employees and directors based on estimated fair values on the date of grant. 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 stock and stock units on a straight-line basis over the requisite service period of the award, which is generally three or 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. Substantially all awards outstanding are classified as equity instruments; therefore, we recognize additional paid in capital as we recognize the compensation expense associated with the awards.

At December 31, 2015, 6,148,009 shares were authorized and available for future grants of share-based awards. Our practice is to satisfy share-based awards by issuing new shares rather than by open-market purchases.

Expenses and capitalized compensation costs recorded by SDG&E were as follows:

SHARE-BASED COMPENSATION EXPENSE
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Compensation expense	$ 8	$ 8	$ 8
Capitalized compensation cost	4	3	3

NON-QUALIFIED STOCK OPTIONS

We use a Black-Scholes option-pricing model (Black-Scholes model) to estimate the fair value of each non-qualified stock option grant. The use of a valuation model requires us to make certain assumptions about selected model inputs. Expected volatility is calculated based on the historical volatility of the stock price. We base the average expected life for options on the contractual term of the option and expected employee exercise and post-termination behavior. The risk-free interest rate is based on U.S. Treasury zero-coupon issues with a remaining term equal to the expected life assumed at the date of the grant. No new options were granted in 2015, 2014 or 2013.

NOTE 7. DERIVATIVE FINANCIAL INSTRUMENTS

We use derivative instruments primarily to manage exposures arising in the normal course of business. Our principal exposures are commodity market risk, benchmark interest rate risk. Our use of derivatives for these risks is integrated into the economic management of our anticipated revenues, anticipated expenses, assets and liabilities. Derivatives may be effective in mitigating these risks (1) that could lead to declines in anticipated revenues or increases in anticipated expenses, or (2) that our asset values may fall or our liabilities increase. Accordingly, our derivative activity summarized below generally represents an impact that is intended to offset associated revenues, expenses, assets or liabilities that are not included in the tables below.

In certain cases, we apply the normal purchase or sale exception to derivative instruments and have other commodity contracts that are not derivatives. These contracts are not recorded at fair value and are therefore excluded from the disclosures below.

In all other cases, we record derivatives at fair value on the Balance Sheet. We designate each derivative as (1) a cash flow hedge, (2) a fair value hedge, or (3) undesignated. Depending on the applicability of hedge accounting and the requirement to pass impacts through to customers, the impact of derivative instruments may be offset in other comprehensive income (loss) (cash flow hedge), on the balance sheet (fair value hedges and regulatory offsets), or recognized in earnings. We classify cash flows from the settlements of derivative instruments as operating activities on the Statement of Cash Flows.

HEDGE ACCOUNTING

We may designate a derivative as a cash flow hedging instrument if it effectively converts anticipated cash flows associated with revenues or expenses to a fixed dollar amount. We may utilize cash flow hedge accounting for derivative commodity instruments, foreign currency instruments and interest rate instruments. Designating cash flow hedges is dependent on the business context in which the instrument is being used, the effectiveness of the instrument in offsetting the risk that the future cash flows of a given revenue or expense item may vary, and other criteria.

We may designate an interest rate derivative as a fair value hedging instrument if it effectively converts our own debt from a fixed interest rate to a variable rate. The combination of the derivative and debt instrument results in fixing that portion of the fair value of the debt that is related to benchmark interest rates. Designating fair value hedges is dependent on the instrument being used, the effectiveness of the instrument in offsetting changes in the fair value of our debt instruments, and other criteria.

ENERGY DERIVATIVES

Our market risk is primarily related to natural gas and electricity price volatility and the specific physical locations where we transact. We use energy derivatives to manage these risks. The use of energy derivatives in our various businesses depends on the particular energy market, and the operating and regulatory environments applicable to the business, as follows:

- We use energy derivatives, both natural gas and electricity, for the benefit of customers, with the objective of managing price risk and basis risks, and stabilizing and lowering natural gas and electricity costs. These derivatives include fixed price natural gas and electricity positions, options, and basis risk instruments, which are either exchange-traded or over-the-counter financial instruments, or bilateral physical transactions. This activity is governed by risk management and transacting activity plans that have been filed with and approved by the CPUC. Natural gas and electricity derivative activities are recorded as commodity costs that are offset by regulatory account balances and are recovered in rates. Net commodity cost impacts on the Statement of Operations are reflected in Cost of Electric Fuel and Purchased Power or in Cost of Natural Gas.
- We are allocated and may purchase congestion revenue rights (CRRs), which serve to reduce the regional electricity price volatility risk that may result from local transmission capacity constraints. Unrealized gains and losses do not impact earnings, as they are offset by regulatory account balances. Realized gains and losses associated with CRRs, which are recoverable in rates, are recorded in Cost of Electric Fuel and Purchased Power on the Statement of Operations.
- From time to time, we may use other energy derivatives to hedge exposures such as the price of vehicle fuel.

We summarize net energy derivative volumes at December 31, 2015 and 2014 as follows:

NET ENERGY DERIVATIVE VOLUMES

	December 31,	
Segment and Commodity	2015	2014

Natural gas	70 million MMBtu (1)	55 million MMBtu
Electricity	1 million MWh (2)	-
Congestion revenue rights	36 million MWh	27 million MWh

(1) Million British thermal units
(2) Megawatt hours

In addition to the amounts noted above, we frequently use commodity derivatives to manage risks associated with the physical locations of contractual obligations and assets, such as natural gas purchases and sales.

FINANCIAL STATEMENT PRESENTATION

The following tables provide the fair values of derivative instruments on the Balance Sheet at December 31, 2015 and 2014, including the amount of cash collateral receivables that were not offset, as the cash collateral is in excess of liability positions.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET
(Dollars in millions)

	December 31, 2015			
	Current assets: Fixed-price contracts and other derivatives(1)	Investments and other assets: Sundry	Current liabilities: Fixed-price contracts and other derivatives(2)	Deferred credits and other liabilities: Fixed-price contracts and other derivatives
Derivatives not designated as hedging instruments:	$	$	$	$
Commodity contracts not subject to rate recovery	-	-	(1)	-
Associated offsetting cash collateral	-	-	1	-
Commodity contracts subject to rate recovery	27	49	(60)	(64)
Associated offsetting commodity contracts	(2)	(2)	2	2
Associated offsetting cash collateral	-	-	28	26
Net amounts presented on the balance sheet	25	47	(30)	(36)
Additional cash collateral for commodity contracts not subject to rate recovery	1	-	-	-
Additional cash collateral for commodity contracts subject to rate recovery	27	-	-	-
Total(3)	$ 53	$ 47	$ (30)	$ (36)

(1) Included in Current Assets.
(2) Included in Current Liabilities.
(3) Normal purchase contracts previously measured at fair value are excluded.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET
(Dollars in millions)

	December 31, 2014			
	Current assets: Fixed-price contracts and other derivatives(1)	Investments and other assets: Sundry	Current liabilities: Fixed-price contracts and other derivatives(2)	Deferred credits and other liabilities: Fixed-price contracts and other derivatives

Derivatives not designated as hedging instruments:								
Commodity contracts subject to rate recovery	$	32	$	76	$	(32)	$	(20)
Associated offsetting commodity contracts		-		(1)		-		1
Associated offsetting cash collateral		-		-		23		13
Net amounts presented on the balance sheet		32		75		(9)		(6)
Additional cash collateral for commodity contracts subject to rate recovery		12		-		-		-
Total(3)	$	44	$	75	$	(9)	$	(6)

(1) Included in Current Assets
(2) Included in Current Liabilities.
(3) Normal purchase contracts previously measured at fair value are excluded.

The effects of derivative instruments not designated as hedging instruments on the Statement of Operations for the years ended December 31 were:

UNDESIGNATED DERIVATIVE IMPACTS
(Dollars in millions)

		Pretax (loss) gain on derivatives recognized in earnings					
		Years ended December 31,					
	Location	2015		2014		2013	
Commodity contracts not subject to rate recovery	Operation and Maintenance	$	-	$	(1)	$	-
Commodity contracts subject to rate recovery	Cost of Electric Fuel and Purchased Power		(126)		(10)		53
Total		$	(126)	$	(11)	$	53

CONTINGENT FEATURES

Certain of our derivative instruments contain credit limits which vary depending on our credit ratings. Generally, these provisions, if applicable, may reduce our credit limit if a specified credit rating agency reduces our ratings. In certain cases, if our credit ratings were to fall below investment grade, the counterparty to these derivative liability instruments could request immediate payment or demand immediate and ongoing full collateralization.

The total fair value of this group of derivative instruments in a net liability position at December 31, 2015 and 2014 is $5 million and $2 million, respectively. At December 31, 2015, if the credit ratings of SDG&E were reduced below investment grade, $6 million of additional assets could be required to be posted as collateral for these derivative contracts.

Some of our derivative contracts contain a provision that would permit the counterparty, in certain circumstances, to request adequate assurance of our performance under the contracts. Such additional assurance, if needed, is not material and is not included in the amounts above.

NOTE 8. FAIR VALUE MEASUREMENTS

Recurring Fair Value Measures

The three tables below, by level within the fair value hierachy , set forth our financial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2015 and 2014. 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 presented in accordance with our netting policy, as we discuss in “Financial Statement Presentation.”

The determination of fair values, shown in the tables below, incorporates various factors, including but not limited to, the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests).

Our financial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2015 and 2014 in the tables below include the following:

- Nuclear decommissioning trusts reflect the assets of SDG&E's nuclear decommissioning trusts, excluding cash balances. A third party trustee values the trust assets using prices from a pricing service based on a market approach. We validate these prices by comparison to prices from other independent data sources. Equity and certain debt securities are valued using quoted prices listed on nationally recognized securities exchanges or based on closing prices reported in the active market in which the identical security is traded (Level 1). Other debt securities are valued based on yields that are currently available for comparable securities of issuers with similar credit ratings (Level 2).
- For commodity contracts and interest rate derivatives we primarily use a market approach with market participant assumptions to value these derivatives. Market participant assumptions include those about risk, and the risk inherent in the inputs to the valuation techniques. These inputs can be readily observable, market corroborated, or generally unobservable. We have exchange-traded derivatives that are valued based on quoted prices in active markets for the identical instruments (Level 1). We also may have other commodity derivatives that are valued using industry standard models that consider quoted forward prices for commodities, time value, current market and contractual prices for the underlying instruments, volatility factors, and other relevant economic measures (Level 2). Level 3 recurring items relate to CRRs and long-term, fixed-price electricity positions at SDG&E, as we discuss below under "Level 3 Information."
- Rabbi Trust investments include marketable securities that we value using a market approach based on closing prices reported in the active market in which the identical security is traded (Level 1). Investments in marketable securities at December 31, 2015 and 2014 were negligible.

There were no transfers into or out of Level 1, Level 2 or Level 3 for SDG&E during the periods presented, nor any changes in valuation techniques used in recurring fair value measurements.

RECURRING FAIR VALUE MEASURES
(Dollars in millions)

	Fair value at December 31, 2015				
	Level 1	Level 2	Level 3	Netting(1)	Total
Assets:					
Nuclear decommissioning trusts					
Equity securities	$ 619	$ -	$ -	$ -	$ 619
Debt securities:					
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	47	44	-	-	91

	Level 1	Level 2	Level 3	Netting(1)	Total
Municipal bonds	-	156	-	-	156
Other securities	-	182	-	-	182
Total debt securities	47	382	-	-	429
Total nuclear decommissioning trusts(2)	$ 666	$ 382	$ -	$ -	$ 1,048
Commodity contracts not subject to rate recovery	-	-	-	1	1
Commodity contracts subject to rate recovery	-	-	72	27	99
Total	$ 666	$ 382	$ 72	$ 28	$ 1,148
Liabilities:					
Commodity contracts not subject to rate recovery	$ 1	$ -	$ -	$ (1)	$ -
Commodity contracts subject to rate recovery	-	67	53	(54)	66
Total	$ 1	$ 67	$ 53	$ (55)	$ 66

	Fair value at December 31, 2014				
	Level 1	Level 2	Level 3	Netting(1)	Total
Assets:					
Nuclear decommissioning trusts					
Equity securities	$ 655	$ -	$ -	$ -	$ 655
Debt securities:					
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	62	47	-	-	109
Municipal bonds	-	129	-	-	129
Other securities	-	207	-	-	207
Total debt securities	62	383	-	-	445
Total nuclear decommissioning trusts(2)	717	383	-	-	1,100
Commodity contracts subject to rate recovery	-	-	107	12	119
Total	$ 717	$ 383	$ 107	$ 12	$ 1,219
Liabilities:					
Commodity contracts not subject to rate recovery	1	-	-	(1)	-
Commodity contracts subject to rate recovery	-	51	-	(36)	15
Total	$ 1	$ 51	$ -	$ (37)	$ 15

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and with cash collateral, as well as cash collateral not offset.
(2) Excludes cash balances and cash equivalents.

Level 3 Information

The following table sets forth reconciliations of changes in the fair value of congestion revenue rights (CRRs) and long-term, fixed-price electricity positions classified as Level 3 in the fair value hierarchy:

LEVEL 3 RECONCILIATIONS
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
Balance at January 1	$ 107	$ 99	$ 61
Realized and unrealized (losses) gains	(134)	15	11
Allocated transmission instruments	12	19	51
Settlements	34	(26)	(24)
Balance at December 31	$ 19	$ 107	$ 99

Change in unrealized (losses) gains relating to instruments still held at December 31	$ (27)	$ 8	$ 11

Our Energy and Fuel Procurement department, in conjunction with the finance group, is responsible for determining the appropriate fair value methodologies used to value and classify CRRs and long-term, fixed-price electricity positions on an ongoing basis. Inputs used to determine the fair value of CRRs and fixed-price electricity positions are reviewed and compared with market conditions to determine reasonableness. We expect all costs related to these instruments to be recoverable through customer rates. As such, there is no impact to earnings from changes in the fair value of these instruments.

CRRs are recorded at fair value based almost entirely on the most current auction prices published by the California ISO, an objective source. Annual auction prices are published once a year, typically in the middle of November, and remain in effect for the following year. The impact associated with discounting is negligible. Because auction prices are a less observable input, these instruments are classified as Level 3. The fair value of these instruments is derived from auction price differences between two locations. From January 1, 2015 to December 31, 2015, the auction prices ranged from $(16) per MWh to $8 per MWh at a given location, and from January 1, 2014 to December 31, 2014, the auction prices ranged from $(6) per MWh to $12 per MWh at a given location. Positive values between two locations represent expected future reductions in congestion costs, whereas negative values between two locations represent expected future charges. Valuation of our CRRs is sensitive to a change in auction price. If auction prices at one location increase (decrease) relative to another location, this could result in a higher (lower) fair value measurement. We summarize CRR volumes in Note 7.

Long-term, fixed-price electricity positions that are valued using significant unobservable data are classified as Level 3 because the contract terms relate to a delivery location or tenor for which observable market rate information is not available. The fair value of the net electricity positions classified as Level 3 is derived from a discounted cash flow model using market electricity forward price inputs. At December 31, 2015, these inputs range from $21.45 per MWh to $60.05 per MWh. A significant increase or decrease in market electricity forward prices would result in a significantly higher or lower fair value, respectively.

Realized gains and losses associated with CRRs and long-term electricity positions, which are recoverable in rates, are recorded in Cost of Electric Fuel and Purchased Power on the Statement of Operations. Unrealized gains and losses are recorded as regulatory assets and liabilities and therefore also do not affect earnings.

Derivative Positions Net of Cash Collateral

Our Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists.

The following table provides the amount of fair value of cash collateral receivables that were not offset in the Balance Sheet at December 31, 2015 and 2014:

	December 31,	
(Dollars in millions)	2015	2014
SDG&E	$ 28	$ 12

Fair Value of Financial Instruments

The fair values of certain of our financial instruments (cash, temporary investments, accounts and notes receivable, current amounts due to/from unconsolidated affiliates, dividends and accounts payable, short-term debt and customer deposits) approximate their carrying amounts because of the short-term nature of these instruments. Investments in life insurance contracts that we hold in support of our Supplemental Executive Retirement, Cash Balance Restoration and Deferred Compensation Plans are carried at cash surrender values, which represent the amount of cash that could be realized under the contracts. The following table provides the carrying amounts and fair values of certain other financial instruments that are not recorded at fair value on the Balance Sheet at December 31:

FAIR VALUE OF FINANCIAL INSTRUMENTS
(Dollars in millions)

	December 31, 2015				
	Carrying amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 3,989	$ -	$ 4,355	$ -	$ 4,355

	December 31, 2014				
	Carrying amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 4,136	$ -	$ 4,563	$ 100	$ 4,663

(1) Before reductions for unamortized discount and debt issuance costs of $43 million and $47 million at December 31, 2015 and 2014, respectively, and excluding capital leases of $244 million and $234 million at December 31, 2015 and 2014, respectively.

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We base the fair value of certain noncurrent amounts due from Sempra Energy's unconsolidated affiliates, long-term debt and preferred stock on a market approach using quoted market prices for identical or similar securities in thinly-traded markets (Level 2). We value other noncurrent amounts due from unconsolidated affiliates of Sempra Energy's South American Utilities using a perpetuity approach based on the obligation's fixed interest rate, the absence of a stated maturity date and a discount rate reflecting local borrowing costs (Level 3). We value other long-term debt using an income approach based on the present value of estimated future cash flows discounted at rates available for similar securities (Level 3).

We provide the fair values for the securities held in the nuclear decommissioning trust funds related to SONGS in Note 10 below.

NOTE 9. PREFERRED STOCK

All series of preferred stock were redeemed during 2013 as we discuss below.

In October 2013, we redeemed all six series of our outstanding shares of contingently redeemable preferred stock for $82 million, including a $3 million early call premium. Each series was redeemed for cash at redemption prices ranging from $20.25 to $26 per share plus accrued dividends up to the redemption date of $1 million. The early call premium is presented as Call Premium on Preferred Stock on the Statement of Operations. The shares are no longer outstanding.

We are currently authorized to issue up to 45 million shares of preferred stock. The rights, preferences, privileges and restrictions for any new series of preferred stock would be established by the board of directors at the time of issuance.

NOTE 10. SAN ONOFRE NUCLEAR GENERATING STATION (SONGS)

We have a 20-percent ownership interest in SONGS, a nuclear generating facility near San Clemente, California, which ceased operations in June 2013. On June 6, 2013, Southern California Edison Company (Edison), the majority owner and operator of SONGS, notified SDG&E that it had reached a decision to permanently retire SONGS and seek approval from the Nuclear Regulatory Commission (NRC) to start the decommissioning activities for the entire facility. SONGS is subject to the jurisdiction of the NRC and the CPUC.

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 expenses and capital expenditures. Our share of operating expenses is included in the Statement of Operations.

SONGS Steam Generator Replacement Project

As part of the Steam Generator Replacement Project (SGRP), the steam generators were replaced in SONGS Units 2 and 3, and the Units returned to service in 2010 and 2011, respectively. Both Units were shut down in early 2012 after a water leak occurred in the Unit 3 steam generator. Edison concluded that the leak was due to unexpected wear from tube-to-tube contact. At the time the leak was identified, Edison also inspected and tested Unit 2 and subsequently found unexpected tube wear in Unit 2’s steam generator. These issues with the steam generators ultimately resulted in Edison’s decision to permanently retire SONGS.

The replacement steam generators were designed and provided by Mitsubishi Heavy Industries, Ltd., Mitsubishi Nuclear Energy Systems, Inc., and Mitsubishi Heavy Industries America, Inc. (collectively MHI). In July 2013, SDG&E filed a lawsuit against MHI seeking to recover damages SDG&E has incurred and will incur related to the design defects in the steam generators. In October 2013, Edison instituted arbitration proceedings against MHI seeking damages as well. SDG&E is participating in the arbitration as a claimant and respondent. We discuss these proceedings in Note 12.

Settlement Agreement to Resolve the CPUC's Order Instituting Investigation (OII) into the SONGS Outage (SONGS OII)

SONGS OII

In November 2012, in response to the outage, the CPUC issued the SONGS OII, pursuant to California Public Utilities’ Code Section 455.5, which applies to cost recovery issues resulting from long-term outages of operating assets. The SONGS OII consolidated most SONGS outage-related issues into a single proceeding. The SONGS OII, among other things, designated all revenues associated with the investment in, and operation of, SONGS since January 1, 2012 as subject to refund to customers, pending the outcome of all phases of the proceeding. The SONGS OII proceeding was intended to determine the ultimate recovery of the investment in SONGS and the costs incurred since the commencement of this outage, including purchased replacement power costs, which are typically recovered through the Energy Resource Recovery Account (ERRA).

Entry Into Settlement Agreement

Pursuant to CPUC rules concerning settlements, SDG&E, Edison, The Utility Reform Network (TURN), and the CPUC Office of Ratepayer Advocates (ORA) held a settlement conference in March 2014 to discuss the terms to resolve the SONGS OII, and in April 2014, SDG&E, along with Edison, TURN, the ORA and two other intervenors who joined the Settlement Agreement to the SONGS OII proceeding (collectively, the Settling Parties), filed a Settlement Agreement with the CPUC. On September 5, 2014, the CPUC issued a ruling proposing specific changes that included, as they relate to SDG&E, greater ratepayer benefit from third party cost recoveries and funding of a research program to reduce greenhouse gas emissions at a shareholder cost of $1 million per year for 5 years.

On September 23,2014, the Settling Parties executed an Amended and Restated Settlement Agreement (Amended Settlement Agreement), which amended the Settlement Agreement to adopt all of the modifications and clarifications requested in the CPUC ruling. On October 9, 2014, the CPUC issued a proposed decision approving the Amended Settlement Agreement, which was adopted by the CPUC as a final decision on November 20, 2014.

As approved by the CPUC, the Amended Settlement Agreement constitutes a complete and final resolution of the SONGS OII and related CPUC proceedings regarding the SGRP at SONGS and the related outage and subsequent shutdown of SONGS. This resolution also required the compliance filing referenced below under “Accounting and Financial Impacts.” The Amended Settlement Agreement does not affect on-going or future proceedings before the NRC, or litigation or arbitration related to potential future recoveries from third parties (except for the allocation to ratepayers of any recoveries as described below) or proceedings addressing decommissioning activities and costs.

In November 2014, in accordance with the Amended Settlement Agreement, SDG&E filed an advice letter seeking authority from the CPUC, among other things, to implement the terms and establish the revenue requirement in accordance with the Amended Settlement Agreement in rates starting January 1, 2015. In December 2014, the CPUC approved the advice letter and authorized SDG&E to update rates accordingly, subject to revision pending the results of a CPUC review of the changes to the revenue requirement proposed by SDG&E for consistency with the terms of the approved settlement decision. In March 2015, SDG&E received a final disposition letter from the CPUC confirming that SDG&E's proposed rate changes were in compliance with the approved settlement decision.

The following is a summary of the Amended Settlement Agreement as it relates to SDG&E.

Disallowances, Refunds and Rate Recoveries

The final decision provided that SDG&E:

- remove from rate base, as of February 1, 2012, its investment in the SGRP and refund to its customers the amount collected for its investment in and any return on its investment in the SGRP since such date. As of February 1, 2012, SDG&E's net book value in the SGRP was approximately $160 million;
- be authorized to recover in rates its remaining investment in SONGS, including base plant and construction work in progress, generally over a ten-year period commencing February 1, 2012, together with a return on investment at a reduced rate equal to:
  - SDG&E's weighted average return on debt, plus
  - 50 percent of SDG&E's weighted average return on preferred stock, as authorized in the CPUC's Cost of Capital proceeding then in effect (collectively, SONGS rate of return or SONGS ROR).

This has resulted in a SONGS ROR of 2.35 percent for the period from January 1, 2013 through December 31, 2015. The SONGS ROR for future periods will fluctuate based on SDG&E's authorized weighted average returns on debt and preferred stock in effect for those future periods. The 2.35 percent SONGS ROR will remain in effect through 2017;

- be authorized to recover in rates its recorded 2012 and 2013 operations and maintenance expenses; in addition, SDG&E was authorized to recover in rates the recorded costs for the 2012 refueling outage of Unit 2, subject to customary prudency review;
- be authorized to recover in rates, subject to a reasonableness review, its 2014 recorded operation and maintenance expenses and non-operating operations and maintenance expenses;
- be authorized to recover in rates its remaining investment in materials and supplies over a ten-year period commencing February 1, 2012, together with a return on investment at the SONGS ROR;
- be authorized to recover in rates its remaining investment in nuclear fuel inventory and any costs incurred, or to be incurred, associated with nuclear fuel supply contracts over a ten-year period, together with a return equal to SDG&E's commercial paper borrowing rate;
- be authorized to recover in rates through its fuel and purchased power balancing account (ERRA), subject to the normal CPUC compliance reviews, all costs incurred to purchase power in the market to replace the power that would have been generated at SONGS if not for the outage and shutdown of SONGS, and to recover by December 31, 2015 any SONGS-related ERRA undercollections, which amounts have been collected. SDG&E's replacement power purchase costs through June 6, 2013 (the date of SONGS' retirement) were approximately $165 million, using the methodology followed in the SONGS OII; and
- have a five-year funding commitment of $1 million per year to the University of California Energy Institute (or other existing University of California entity engaged in energy technology development) to create a Research Development and Demonstration program, whose goal would be to deploy new technologies, methodologies, and /or design modifications to reduce GHG emissions, particularly at current and future generating plants in California. This term was a modification requested by the CPUC.

In April 2015, a petition for modification (PFM) was filed with the CPUC by Alliance for Nuclear Responsibility (A4NR), an intervenor in the SONGS OII proceeding, asking the CPUC to set aside its decision approving the Amended Settlement Agreement and reopen the SONGS OII proceeding. In June 2015, TURN, a party to the Amended Settlement Agreement, filed a response supporting the A4NR petition. TURN does not question the merits of the Amended Settlement Agreement, but is concerned that certain allegations regarding Edison raised by A4NR have undermined the public's confidence in the regulatory process. SDG&E has responded that TURN's concerns regarding public perception do not impact the reasonableness of the Amended Settlement Agreement and are insufficient to overturn it. SDG&E is unable to determine what actions the CPUC will take, if any, in response to the A4NR PFM.

In August 2015, ORA, also a party to the Amended Settlement Agreement, filed a PFM with the CPUC, withdrawing its support for the Amended Settlement Agreement and asking the CPUC to reopen the SONGS OII proceeding. The ORA does not question the merits of the Amended Settlement Agreement, but is concerned with the CPUC's approach toward recent disclosures concerning Edison ex parte communications with the CPUC. SDG&E responded that the ORA's PFM is insufficient to overturn the Amended Settlement Agreement, because the ORA fails to make a case that the Amended Settlement Agreement is no longer in the public interest. SDG&E is unable to determine what actions the CPUC will take, if any, in response to the ORA PFM.

Accounting and Financial Impacts

Through December 31, 2015, the cumulative after-tax loss from plant closure recorded by SDG&E is $125 million, including a reduction in the after-tax loss of $13 million recorded in the first quarter of 2015 based on the CPUC's approval in March 2015 of SDG&E's compliance filing and establishment of the SONGS settlement revenue requirement, and a reduction in the after-tax loss of $2 million based on a settlement with Nuclear Electric Insurance Limited in the fourth quarter of 2015, as we discuss below.

In the second quarter of 2013, based on an initial assessment of the financial impact of the outcome of the SONGS OII proceeding, SDG&E reported an after-tax loss from plant closure of $119 million. In the first quarter of 2014, after entering into the Settlement Agreement, SDG&E recorded a $9 million increase in the after-tax loss. In the fourth quarter of 2014, based on the compliance filing regarding SDG&E's annual revenue requirement and the timing of refunds to ratepayers, SDG&E recorded a $12 million increase to the after-tax loss.

The regulatory asset for the expected recovery of SONGS costs, consistent with the Amended Settlement Agreement, is $257 million ($42 million current and $215 million long-term) at December 31, 2015 and is recorded on the Balance Sheet in Regulatory Assets Current and Other Regulatory Assets Noncurrent, respectively. The amortization period prescribed for the regulatory asset is 10 years, which began on February 1, 2012. However, since the CPUC's final decision approving the Amended Settlement Agreement was not issued until November 2014, amortization did not commence until January 2015.

Settlement with Nuclear Electric Insurance Limited (NEIL)

As we discuss in Note 12, NEIL insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks. In October 2015, the SONGS co-owners (Edison, SDG&E and the City of Riverside) reached an agreement with NEIL to resolve all of SONGS' insurance claims arising out of the failures of the replacement steam generators for a total payment by NEIL of $400 million, our share of which is $80 million. Pursuant to the terms of the SONGS OII Amended Settlement Agreement, after reimbursement of legal fees and a 5-percent allocation to shareholders, the net proceeds of $75 million were allocated to ratepayers through ERRA.

NRC Proceedings

In December 2013, Edison received a final NRC Inspection Report that identified a violation for the failure to verify the adequacy of the thermal-hydraulic and flow-induced vibration design of the Unit 3 replacement steam generator. In January 2014, Edison provided a response to the NRC Inspection Report stating that MHI, as contracted by Edison to prepare the SONGS replacement steam generator design, was the party responsible for validating the design of the steam generators.

In addition, the NRC issued an Inspection Report to MHI containing a Notice of Nonconformance for its flawed computer modeling in the design of the replacement steam generators.

Because SONGS has ceased operation, NRC inspection oversight of SONGS will now be continued through the NRC's Decommissioning Power Reactor Inspection Program to verify that decommissioning activities are being conducted safely, that spent fuel is safely stored onsite or transferred to another licensed location, and that the site operations and licensee termination activities conform to applicable regulatory requirements, licensee commitments and management controls.

Nuclear Decommissioning and Funding

As a result of Edison's decision to retire SONGS Units 2 and 3, Edison has begun the decommissioning phase of the plant. The process of decommissioning a nuclear power plant is governed by the regulations of various governmental and other agencies, including but not limited to, those of the NRC, the U.S. Department of the Navy (the land owner) and the CPUC. The NRC regulations generally categorize the decommissioning activities into three phases: initial activities, major decommissioning and storage activities, and license termination. Initial activities include providing notice of permanent cessation of operations (provided by Edison to the NRC on June 12, 2013) and notice of permanent removal of fuel from the reactor vessels (provided by Edison on June 28 and July 22, 2013 for Units 3 and 2, respectively). Within two years after the cessation of operations, the licensee (Edison) must submit a post-shutdown decommissioning activities report (PSDAR), an irradiated fuel management plan (IFMP) and a site-specific decommissioning cost estimate (DCE). Edison submitted each of the PSDAR, the IFMP and the DCE to the NRC in September 2014.

In accordance with state and federal requirements and regulations, SDG&E has assets held in trusts, referred to as the Nuclear Decommissioning Trusts (NDT), to fund decommissioning costs for SONGS Units 1, 2 and 3. Decommissioning of Unit 1, removed from service in 1992, is largely complete. The remaining work will be done when Units 2 and 3 are decommissioned. At December 31, 2015, the fair value of SDG&E's NDT assets was $1.1 billion. Except for the use of funds for the planning of decommissioning activities or NDT administrative costs, CPUC approval is required for SDG&E to access the NDT assets to fund SONGS decommissioning costs for Units 2 and 3. In February 2014, SDG&E filed a request with the CPUC for such authorization for costs incurred in 2013. In April 2015, SDG&E withdrew its pending request and filed a new request based on updated decommissioning cost information, seeking authorization to access trust funds for up to $55 million in decommissioning costs incurred in 2013. The CPUC authorized the request in July 2015. In August 2015, SDG&E withdrew $37 million of the authorized amount, $34 million of which will be funded to customers through the ERRA balancing account. Another $3 million of the amount withdrawn was used to refund regulatory assets and certain costs pursuant to the SONGS OII Settlement Agreement. The remaining $18 million of the CPUC authorization is expected to be withdrawn pending satisfactory clarification by the Internal Revenue Service (IRS) that certain spent fuel costs and other costs are eligible decommissioning costs, payable from qualified nuclear decommissioning trusts. We are uncertain as to when such clarification will be provided.

In October 2015, we filed a request with the CPUC seeking authorization to access trust funds for $36 million for SONGS Units 2 and 3 decommissioning costs incurred in 2014. The CPUC approved the request in November 2015. In December 2015, SDG&E withdrew $23 million of the authorized amount, $19 million of which will be funded to customers through the ERRA balancing account. Another $4 million of the amount withdrawn was used to refund regulatory assets and certain costs pursuant to the SONGS OII Settlement Agreement. The remaining $13 million will be withdrawn pending satisfactory clarification by the IRS, as discussed above.

We will continue to use working capital to pay for any SONGS Units 2 and 3 decommissioning costs incurred, and file periodic requests with the CPUC seeking authorization to access funds for reimbursement from the NDT for incurred decommissioning costs.

Nuclear Decommissioning Trusts

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 the Balance Sheet at fair value with the offsetting credits recorded in 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 NDT. We provide additional fair value disclosures for the NDT in Note 8.

NUCLEAR DECOMMISSIONING TRUSTS

(Dollars in millions)

	Cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value
At December 31, 2015:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies(1)	$ 89	$ 2	$ -	$ 91
Municipal bonds(2)	148	8	-	156
Other securities(2)	194	1	(13)	182
Total debt securities	431	11	(13)	429
Equity securities	214	412	(7)	619
Cash and cash equivalents	15	-	-	15
Total	$ 660	$ 423	$ (20)	$ 1,063
At December 31, 2014:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	$ 103	$ 6	$ -	$ 109
Municipal bonds	121	8	-	129
Other securities	206	7	(6)	207
Total debt securities	430	21	(6)	445
Equity securities	215	444	(4)	655
Cash and cash equivalents	30	1	-	31
Total	$ 675	$ 466	$ (10)	$ 1,131

(1) Maturity dates are 2016-2065.
(2) Maturity dates are 2016-2115.

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

SALES OF SECURITIES
(Dollars in millions)

	Years ended December 31, 2015	2014	2013
Proceeds from sales(1)	$ 577	$ 601	$ 685
Gross realized gains	29	11	26
Gross realized losses	(15)	(11)	(18)

(1) Excludes securities that are held to maturity.

Net realized gains (losses) are included in Regulatory Liabilities Arising from Removal Obligations on SDG&E's Balance Sheet. We determine the cost of securities in the trusts on the basis of specific identification.
Ratepayer 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 ratepayer contributions.

Asset Retirement Obligation and Spent Nuclear Fuel

Our asset retirement obligation related to decommissioning costs for the SONGS units was $667 million at December 31, 2015. That amount includes the cost to decommission Units 2 and 3, and the remaining cost to complete the decommissioning of Unit 1, which is substantially complete. The asset retirement obligation at December 31, 2015 is based on an updated cost study prepared in 2014 that reflects the acceleration of the start of decommissioning Units 2 and 3 as a result of the early closure of the plant. Our share of decommissioning costs in 2014 dollars is approximately $937 million, or escalated to 2015 dollars, is $956 million.

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 decommissioning of Unit 1 remaining structures (subsurface and intake/discharge) will take place as Units 2 and 3 are decommissioned. The ISFSI will be decommissioned after a spent fuel 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 fully decommissioned. Until then, SONGS owners are responsible for interim storage of spent nuclear fuel at SONGS until the DOE accepts it for final disposal. Spent nuclear fuel for Units 2 and 3 has been stored in the SONGS spent fuel pools for each reactor and in the ISFSI.

We provide additional information about SONGS in Note 12.

NOTE 11. REGULATORY MATTERS

CPUC General Rate Case (GRC)

The CPUC uses a general rate case proceeding to set sufficient rates to allow us to recover their reasonable cost of operations and maintenance and to provide the opportunity to realize their authorized rates of return on their investment.

2016 General Rate Case (2016 GRC)

We filed our 2016 General Rate Case (2016 GRC) applications in November 2014. These filings requested revenue requirement increases of $133 million over our 2015 revenue requirement.

In September 2015, we filed a settlement agreement with the CPUC that resolves all material matters related to the proceeding, except for the revenue requirement implications of certain income tax benefits associated with flow-through repair allowance tax deductions, discussed below. The settlement agreements are with eight of eleven intervening parties. For SDG&E, the settlement proposes a total revenue requirement in 2016 of $1.811 billion, which is $100 million less than its original request (as revised). The proposed settlement represents an increase of $17 million, or one percent over the 2015 total revenue requirement. This increase reflects a $16 million adjustment to the 2015 estimated revenue requirement since the November 2014 filings. The filed settlement agreements also call for attrition adjustments of 3.5 percent for both 2017 and 2018. We also filed a separate agreement, reached with ORA, proposing that a fourth year (2019) be added to the GRC period, with a revenue requirement increase of 4.3 percent over 2018. Because the 2016 settlement has not been finalized, we will collect rates identical to 2015 authorized amounts until a 2016 decision is approved.

The settlement agreement described above exclude a proposal regarding certain intra-rate case income tax benefits. The proposal recommends that the CPUC adjust our rate base by $93 million, and additionally reduce our revenue requirement by amounts currently being tracked in tax memorandum accounts for the year 2015. At December 31, 2015, the pretax balances tracked in these memorandum accounts $39 million. We believe the proposed treatment would violate and contradict long standing rate making and income tax policy, and would represent a material departure from historical practice. If this proposal is adopted, the outcome would reduce the revenue requirement amounts agreed to in the settlement agreement described above. We do not expect that the prospective reduction to rate base described above would result in an immediate earnings impact if this proposal is adopted. However, if this proposal is adopted, the amounts currently being tracked in the tax memorandum accounts for 2015 could result in a material charge against earnings when the draft decision is received.

We anticipate all matters to be resolved in the CPUC’s final decision on the 2016 GRC proceeding. We expect the CPUC to issue a final decision in the proceeding in the second quarter of 2016.

2012 General Rate Case (Final 2012 GRC Decision)

In May 2013, the CPUC approved a final decision in our 2012 GRC. The Final 2012 GRC Decision was effective retroactive to January 1, 2012, and we recorded the cumulative earnings effect of the retroactive application of the Final 2012 GRC Decision of $69 million in the second quarter of 2013. For SDG&E, these amounts included an incremental earnings impact of $52 million related to 2012 and $17 million related to the first quarter of 2013.

The amount of revenue associated with the retroactive period was recovered in SDG&E’s rates over a 28-month period beginning in September 2013. At December 31, 2014, we reported on our Balance Sheet $162 million as a regulatory asset, all classified as current, representing the retroactive revenue from the Final 2012 GRC Decision recovered by SDG&E in rates in 2015.

CPUC Cost of Capital

A CPUC cost of capital proceeding determines a utility's authorized capital structure and authorized rate of return on rate base (ROR), which is a weighted average of the authorized returns on debt, preferred stock, and common equity (return on equity or ROE), weighted on a basis consistent with the authorized capital structure. The authorized ROR is the rate that we are authorized to use in establishing rates to recover the cost of debt and equity used to finance their investment in CPUC-regulated electric distribution and generation as well as natural gas distribution, transmission and storage assets.

In addition, a cost of capital proceeding also addresses the automatic cost of capital adjustment mechanism (CCM) which applies market-based benchmarks to determine whether an adjustment to the authorized ROR is required during the interim years between cost of capital proceedings. The market-based benchmark for our CCM is the 12-month average monthly A-rated utility bond index, as published by Moody's for the 12-month period of October 1st through September 30th (CCM Period) of each calculation year. In the last cost of capital proceeding, Our CCM benchmark rate was set at 4.24 percent. If at the end of the CCM Period the monthly average benchmark rate falls outside of the established range of 3.24 percent to 5.24 percent, our authorized ROE would be adjusted, upward or downward, by one-half of the difference between the 12-month average and the benchmark rate. In addition, the authorized recovery rate for our cost of debt and preferred stock would be adjusted to their respective actual weighted average costs, with no change to the authorized capital structure. All three adjustments with the new rate would become effective on January 1st of the following year in which the benchmark range was exceeded. For the twelve-month period ended September 30, 2015, the 12-month average of monthly Moody's A-rated utility bond index was 4.04 percent, which is within the established range of 3.24 percent and 5.24 percent.

The CCM only applies during the intervening years between scheduled cost of capital proceedings. In the year the cost of capital proceeding is scheduled, the cost of capital proceeding takes precedence over CCM and will set new rates for the following year.

In December 2014, the CPUC granted us an extension of its filing deadlines for their next cost of capital applications by one year, from April 2015 to April 2016. The CPUC also extended the current CCM until the April 2016 filing date. The one year extension was made in response to a joint request by SDG&E, SoCalGas, Pacific Gas and Electric Company (PG&E) and Edison with the CPUC in November 2014.

In November 2015, the CPUC granted us an extension of its filing deadlines for one more year to April 2017. This additional extension was made in response to a joint request with the CPUC by SDG&E, SoCalGas, PG&E and Edison. The CPUC also extended the current CCM until the April 2017 filing date. However, in the event the adjustment mechanism is triggered, the utilities agree that no changes to the current cost of capital will be made under the mechanism. In February 2016, the CPUC approved a joint PFM filed by the California Utilities, the ORA and TURN to effectuate the agreement among the parties.

Our current CPUC-authorized ROR is 7.79 percent based on their authorized capital structures as follows:

COST OF CAPITAL AND AUTHORIZED RATE STRUCTURE

Authorized weighting	Authorized rate of recovery	Weighted authorized ROR	
45.25%	5.00%	2.26%	**Long-Term Debt**
2.75%	6.22%	0.17%	**Preferred Stock**
52.00%	10.30%	5.36%	**Common Equity**
100.00%		**7.79%**	

We file separately with the FERC for authorized ROE on FERC-regulated electric transmission operations and assets as described below in "Federal Energy Regulatory Commission (FERC) Formulaic Rate Matters".

Natural Gas Pipeline Operations Safety Assessments

Various regulatory agencies, including the CPUC, are evaluating natural gas pipeline safety regulations, practices and procedures. In February 2011, the CPUC opened a forward-looking rulemaking proceeding to examine what changes should be made to existing pipeline safety regulations for California natural gas pipelines. The California Utilities are parties to this proceeding.

In June 2011, the CPUC directed SoCalGas, SDG&E, PG&E and Southwest Gas to file comprehensive implementation plans to test or replace natural gas transmission pipelines located in populated areas that have not been pressure tested. We filed our Pipeline Safety Enhancement Plan (PSEP) with the CPUC in August 2011. Our total estimated cost for Phase 1 of the two-phase plan to be $500 million over the 10-year period of 2012 to 2022. We anticipate that these costs may be updated to reflect the development of more detailed estimates, actual costs experienced as portions of the work are completed and changes in scope. We requested that the incremental capital investment required as a result of any approved plan be included in rate base and that cost recovery be allowed for any other incremental cost not eligible for rate-base recovery. The costs that are the subject of these plans were outside the scope of the 2012 GRC proceedings concluded in 2013. Similarly, these costs are not included in our 2016 GRC filing.

In April 2012, the CPUC transferred the PSEP to the Triennial Cost Allocation Proceeding (TCAP) and authorized SDG&E establish regulatory accounts to record the incremental costs of initiating the PSEP prior to a final decision on the PSEP.

Also in April 2012, the CPUC issued a decision expanding the scope of the rulemaking proceeding to incorporate the provisions of California Senate Bill (SB) 705, which requires gas utilities to develop and implement a plan for the safe and reliable operation of their gas pipeline facilities. SDG&E submitted their pipeline safety plans in June 2012. The CPUC decision also orders the utilities to undergo independent management and financial audits to assure that the utilities are fully meeting their safety responsibilities. The CPUC's Safety and Enforcement Division will select the independent auditors and will oversee the audits. A schedule for the audits has not been established. In December 2012, the CPUC issued a final decision accepting the utilities' pipeline safety plans filed pursuant to SB 705.

In June 2014, the CPUC issued a final decision in the TCAP proceeding addressing SDG&E's PSEP. Specifically, the decision determined the following for Phase 1 of the program:

- approved the utilities' model for implementing PSEP;
- approved a process, including a reasonableness review, to determine the amount that we will be authorized to recover from ratepayers for the interim costs incurred through the date of the final decision to implement PSEP, which is recorded in the regulatory accounts authorized by the CPUC as noted above;
- approved balancing account treatment, subject to a reasonableness review, for incremental costs yet to be incurred to implement PSEP; and
- established the criteria to determine the amounts that would not be eligible for cost recovery, including:
    - certain costs incurred or to be incurred searching for pipeline test records,
    - the cost of pressure testing pipelines installed after July 1, 1961 for which the company has not found sufficient records of testing, and
    - any undepreciated balances for pipelines installed after 1961 that were replaced due to insufficient documentation of pressure testing.

After taking the amounts disallowed for recovery into consideration, as of December 31, 2015, We have recorded PSEP costs of $10 million in the CPUC-authorized regulatory account. In regard to requesting recovery from customers for PSEP costs incurred and recorded in accordance with the TCAP decision, we are authorized to file an application with the CPUC for recovery of such costs up to the date of the TCAP decision and then annually for costs incurred through the end of each calendar year beginning with the period ended December 31, 2015. We currently expect to file such application no later than the second quarter of the year following and would expect a decision from the CPUC approximately 12 to 18 months following the date of the application (i.e., a decision on the recovery of costs recorded in the PSEP regulatory accounts as of December 31, 2015 would be expected by mid-2017).

In October 2014, we filed a petition for modification with the CPUC requesting authority to begin to recover PSEP costs from customers in the year in which the costs are incurred, subject to refund pending the results of a reasonableness review by the CPUC, instead of in a subsequent year. This request is pending at the CPUC.

In December 2014, we filed an application with the CPUC for recovery of $0.1 million in costs recorded in the regulatory account through June 11, 2014. In June 2015, we agreed to remove certain projects from the filing and defer their review to future proceedings and, as a result, is now requesting recovery of $0.1 million. The ORA, TURN, and the Southern California Generation Coalition (SCGC) have recommended disallowances related to completed projects, as well as facilities build-out costs, de-scoped projects, and project management and consulting costs.

In July 2014, the ORA and TURN filed a joint application for rehearing of the CPUC's June 2014 final decision. The ORA and TURN alleged that the CPUC made a legal error in directing that ratepayers, not shareholders, be responsible for the costs associated with testing or replacing transmission pipelines that were installed between January 1, 1956 and July 1, 1961 for which we do not have a record of a pressure test. In November 2014, the CPUC denied the ORA and TURN request for rehearing of the decision adopting the PSEP. In December 2014, the ORA and TURN sought rehearing of the CPUC's decision on rehearing. In late December 2014, we filed our opposition to this second application for rehearing, and is continuing to implement PSEP in accordance with the June 2014 CPUC decision. In March 2015, the CPUC issued a decision denying the ORA's and TURN's second request for rehearing, but keeping the record in the proceeding open to admit additional evidence on the limited issue of pressure testing of pipelines installed between January 1, 1956 and July 1, 1961. As part of this review, the CPUC will allow parties to submit additional evidence relevant to this narrow issue to ensure a complete record, with no additional discovery allowed. The ORA and TURN filed their responses on May 1, 2015. In December 2015, the CPUC issued a final decision finding that ratepayers should not bear the costs associated with pressure testing subject pipelines, or, if replaced, ratepayers should bear neither the average cost of pressure testing nor the undepreciated balance of abandoned pipelines. Through December 31, 2015, the after-tax disallowed costs is $0.5 million. In January 2016, we filed a request with the CPUC seeking rehearing of our December 2015 decision. A CPUC decision on the rehearing request is expected in 2016.

Utility Incentive Mechanisms

The CPUC applies performance-based measures and incentive mechanisms to all California investor-owned utilities (IOUs), under which the California Utilities have earnings potential above authorized base margins if they achieve or exceed specific performance and operating goals. Generally, for performance-based awards, if performance is above or below specific benchmarks, the utility is eligible for financial awards or subject to financial penalties. We have has incentive mechanisms associated with:

- operational incentives
- energy efficiency

Incentive awards are included in our earnings when we receive any required CPUC approval of the award. We would record penalties for results below the specified benchmarks in earnings when we believe it is probable that the CPUC would assess a penalty.

Energy Efficiency

The CPUC established incentive mechanisms that are based on the effectiveness of energy efficiency programs. In December 2013, the CPUC awarded $3.9 million to SDG&E for its 2011 program year results. In December 2014, the CPUC approved awards to SDG&E of $ $7.5 million for program year 2012 and for the first half of program year 2013. In December 2015, the CPUC approved awards to SDG&E of $6.5 million for the second half of program year 2013 and all of program year 2014.

In September 2015, the CPUC issued a decision granting two rehearing requests filed by the ORA and TURN regarding the utility incentive awards for SDG&E for program years 2006 through 2008, which totaled $16.2

million. The decision directs that the rehearing ensure that the incentive awards granted were just and reasonable and based on calculations verified by the CPUC, or otherwise refunded to customers. We expect a CPUC decision in the second half of 2016.

Natural Gas Procurement

We procure natural gas on behalf of our core natural gas customers. The CPUC has established incentive mechanisms to allow us the opportunity to share in the savings and/or costs from buying natural gas for our core customers at prices below or above monthly market-based benchmarks. SoCalGas procures natural gas for our core natural gas customers' requirements.

Operational Incentives

The CPUC may establish operational incentives and associated performance benchmarks as part of a general rate case or cost of service proceeding. In our Final 2012 GRC Decision, we were directed to establish a performance measure and incentive for electric reliability. In September 2014, the CPUC approved SDG&E's proposed mechanism, which was applied to calendar year 2015 and will be considered in the 2016 GRC.

SONGS

We discuss regulatory and other matters related to SONGS in Note 10.

Power Procurement and Resource Planning

We discuss our major projects below in "California Utilities – Major Projects."

Background - Electric Industry Regulation

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 Natural Gas, to provide power for the utility procurement customers of each of the California IOUs, including SDG&E. The CPUC allocates the power and its administrative responsibility, including collection of power contract costs from utility customers, among the IOUs. The last of these power contracts expired in 2013, with one remaining transportation contract allocated to SDG&E that will expire in 2018.

Renewable Energy

We are subject to the Renewables Portfolio Standard (RPS) Program administered by both the CPUC and the California Energy Commission, which requires each California utility to procure 33 percent of its annual electric energy requirements from renewable energy sources by 2020, with an average of 20 percent required from January 1, 2011 to December 31, 2013; 25 percent by December 31, 2016; and 33 percent by December 31, 2020. The CPUC began a rulemaking proceeding in May 2011 to address the implementation of the 33% RPS Program.

The 33% RPS Program contains flexible compliance mechanisms that can be used to comply with or meet the 33% RPS Program mandates in 2011 and beyond. The mechanisms provide for a CPUC waiver under certain conditions, including: 1) a finding of inadequate transmission; 2) delays in the start-up of commercial operations of renewable energy projects due to permitting or interconnection; or 3) unexpected curtailment by an electric system balancing authority, such as the California ISO.

We continue to procure renewable energy supplies to achieve the 33% RPS Program requirements. A substantial number of these supply contracts, however, are contingent upon many factors, including:

- access to electric transmission infrastructure;

- 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.

In August 2014, we made a required filing with the CPUC indicating that its procurement of renewable energy during the period January 1, 2011 through December 31, 2013 exceeded the 20-percent minimum amount required by RPS. We believe it will be able to comply with the 33% RPS Program requirements based on its contracting activity and, if necessary, application of the flexible compliance mechanisms. Our failure to comply with the RPS Program requirements could subject it to CPUC-imposed penalties, which could materially affect its business, cash flows, financial condition, results of operations and/or prospects. The limit on the total amount of penalties for failure to comply with the RPS requirements is $75 million for the first compliance period (2011-2013); $75 million for the second compliance period (2014-2016); $100 million for the third compliance period (2017-2020); and $25 million for each annual compliance period beginning in 2021.

SB 350, signed into law in October 2015, increased the RPS requirements to 50 percent by 2030, with interim targets of 40 percent by the end of 2024, and 45 percent by the end of 2027. SDG&E expects to be fully compliant with these RPS requirements. We expect the CPUC to begin implementation of SB 350 in 2016.

Sunrise Powerlink Electric Transmission Line

In August 2015, we filed a petition with the CPUC requesting that it revise and confirm the project cost cap for the Sunrise Powerlink, a 500-kilovolt (kV) electric transmission line between the Imperial Valley and the San Diego region that was energized and placed in service in June 2012. While post-energization construction activities for the project were completed in 2013, certain matters relating to outstanding claims were not resolved until the first quarter of 2015. The filing requests CPUC approval of the final expenditure report for the project and the proposed revisions to the total project cost cap. As evidenced in the final report, and summarized in the table below, actual expenditures for the project totaled $1,887.4 million (in 2012 dollars, on a net present value basis), which exceeds the total project cost cap approved by the CPUC in 2008 (CPUC Approval Decision) by $4.4 million.

SUNRISE POWERLINK ELECTRIC TRANSMISSION LINE – PROPOSED REVISIONS TO TOTAL PROJECT COST CAP
(Dollars in millions)

	Construction costs and AFUDC	Undergrounding on Alpine Blvd.	Mitigation and monitoring costs	Total (2012 dollars, net present value basis)
Final status report	$ 1,490.9	$ 11.7	$ 384.8	$ 1,887.4
2008 CPUC approval decision	1,594.2	91.0	197.8	1,883.0
Difference	$ (103.3)	$ (79.3)	$ 187.0	$ 4.4

Subsequent to the required approvals of the U.S. Department of Interior, Bureau of Land Management in January 2009 and the U.S. Forest Service (USFS) in July 2010, which formed the basis of the CPUC Approval Decision summarized above, the CPUC's Energy Division and the federal agencies published the Sunrise Final Mitigation Monitoring, Compliance, and Reporting Program (MMCRP). The MMCRP increased the amount of required mitigation activities and costs by $187 million. Offsetting this cost, in part, was a reduction in the total mileage of undergrounding on Alpine Boulevard by approximately two miles. The terms of the CPUC Approval Decision contemplate the potential reduction in undergrounding mileage at an estimated $11 million per one quarter mile. The CPUC Approval Decision did not anticipate the changes in monitoring and mitigation costs. In our petition, we propose that the applicable total cost cap be revised and confirmed at the amount of $1,887.4 million. This amount will be the basis used in our FERC-regulated transmission rates. Our expect a CPUC decision on the petition in 2016.

Federal Energy Regulatory Commission (FERC) Formulaic Rate Matters

In February 2013, we submitted our Electric Transmission Formula Rate (TO4) filing with the FERC to set the rate making methodology and rate of return for our FERC-regulated electric transmission operations and assets for a multi-year period beginning September 1, 2013. The TO4 filing proposed a FERC ROE of 11.3 percent and requested: 1) rates to be determined by a base period of historical costs and a forecast of capital investments and 2) a true-up period similar to balancing account treatment that is designed to provide earnings of no more and no less than our actual cost of service including its authorized return on investment. In June and July 2013, the FERC issued orders accepting the filing, subject to refund, and established settlement and hearing procedures, with rates being effective September 1, 2013.

On January 31, 2014, we filed an uncontested multi-party settlement at the FERC regarding the TO4 filing. The settlement, approved by the FERC in May 2014, will be in effect through December 31, 2018, is subject to a one-time right of termination by any party, and established a 10.05 percent ROE. The settlement also requires SDG&E to make annual information filings on December 1 of a given year to update rates for the following calendar year. We also have the right to file for any ROE incentives that might apply under FERC rules. SDG&E's debt to equity ratio will be set annually based on the actual ratio at the end of each year.

Energy Resource Recovery Account (ERRA)

The ERRA is the regulatory balancing account that we use to recover the electric fuel and purchased power costs it incurs to provide energy to its bundled service customers. SDG&E files an application with the CPUC each year to establish the ERRA revenue requirement needed for the following calendar year. Additionally, to the extent the ERRA balance exceeds a certain tolerance or "ERRA Trigger", we must file an application to adjust its rates upward or downward, as applicable, to address the under- or overcollected ERRA balance, respectively. In 2014, the CPUC authorized SDG&E to collect $221 million of revenue requirement as a result of an ERRA Trigger. We collected the revenue requirement over the period April 2014 through December 31, 2015. In December 2015, the CPUC approved SDG&E's 2016 ERRA revenue requirement of $1.3 billion, an increase of $43 million from its 2015 revenue requirement. We implemented the increased revenue requirement, to be collected in 2016, beginning January 1.

Wildfire Claims Cost Recovery

In August 2009, SDG&E and SoCalGas filed an application, along with other related filings, with the CPUC proposing a new framework and mechanism for the future recovery of all wildfire-related expenses for claims, litigation expenses and insurance premiums that are in excess of amounts authorized by the CPUC for recovery in distribution rates. In December 2012, the CPUC issued a final decision that ultimately did not approve the proposed framework for the utilities but allowed SDG&E to maintain its authorized memorandum account so that we may file applications with the CPUC requesting recovery of amounts properly recorded in the memorandum account at a later time, subject to reasonableness review.

In February 2014, the Presiding Judge assigned by the FERC to SDG&E's annual Electric Transmission Formula Rate filing (TO3 Formula Cycle 6) issued an Initial Decision and an Order on Summary Judgment which authorizes SDG&E to recover all of the costs incurred and allocated to SDG&E's FERC-regulated operations for the 12-month period ended March 31, 2012, resulting from settlement activities for 2007 wildfire claims. In connection with this proceeding, the CPUC filed an appeal in the Ninth Circuit Court of Appeal of an earlier decision by the FERC denying the CPUC's request to postpone the FERC proceeding pending CPUC action on cost recovery of the excess wildfire costs. The FERC sought dismissal of the CPUC's appeal on procedural grounds, and in December 2015, the Court of Appeal dismissed the appeal.

In September 2015, we filed an application with the CPUC requesting rate recovery of an estimated $379 million in costs related to the October 2007 wildfires that have been recorded to the Wildfire Expense Memorandum Account (WEMA). These costs represent a portion of the estimated total of $2.4 billion in costs and legal fees that we have incurred to resolve third-party damage claims arising from the October 2007 wildfires. The requested amount of $379 million is the net estimated cost incurred by SDG&E after deductions for insurance reimbursement ($1.1 billion), third party settlement recoveries ($824 million) and allocations to FERC-jurisdictional rates ($80 million), and reflects a voluntary 10 percent shareholder contribution applied to the net WEMA balance ($42 million). We requested a CPUC decision by the end of 2016 and is proposing to recover the costs in rates over a six- to ten-year period. Intervening parties have recommended a phased approach, with Phase 1 addressing the reasonableness of our actions leading up to the fires and a CPUC decision in the second half of 2017. Phase 2 would address the reasonableness of settlements entered into by SDG&E, with a CPUC decision in the second half of 2018.

We discuss the impact should SDG&E conclude that recovery in rates is no longer probable in "Legal Proceedings – SDG&E – 2007 Wildfire Litigation" in Note 12. We discuss how we assess the probability of recovery of our regulatory assets in Note 1.

CALIFORNIA UTILITIES-MAJOR PROJECTS

MAJOR PROJECTS – JOINT UTILITIES

(Dollars in millions)

Project description	Estimated cost	Status
Southern Gas System Reliability Project ▪ 2013 application seeking authority to recover the full cost of the project. ▪ Will enhance reliability on the southern portions of the California Utilities' integrated natural gas transmission system (Southern System). ▪ Also known as the North-South Gas Project.	$ 800 to $ 850	▪ In March 2015, CPUC issued a revised project scope and updated schedule. ▪ If approved, and subject to environmental permitting, the project could commence construction in 2017 and be in service by the end of 2019.
Pipeline Safety & Reliability Project ▪ September 2015 application seeking authority to recover the full cost of the project, involving construction of an approximately 47-mile, 36-inch natural gas transmission pipeline in San Diego County. ▪ Will implement pipeline safety requirements and modernize the system; improve system reliability and resiliency by minimizing dependence on a single pipeline; and enhance operational flexibility to manage stress conditions by increasing system capacity.	$ 600	▪ January 2016 ruling directing SDG&E and SoCalGas to file an amended application by March 21, 2016 and provide additional information and analysis regarding various project alternatives. ▪ After CPUC approval, and subject to timing of other approvals, will take approximately 24 to 36 months to construct.

MAJOR PROJECTS - SDG&E

(Dollars in millions)

Project description	Estimated cost	Status
Cleveland National Forest (CNF) Transmission Projects ▪ 2012 application for permit to construct various transmission line replacement projects in and around CNF. ▪ To replace and fire-harden five existing transmission lines.	$ 400 to $ 450	▪ Alternatives identified in July 2015 joint CPUC/USFS environmental impact report (EIR/EIS), if approved by CPUC and USFS, would result in an increase to the estimated cost of the projects. ▪ Separate USFS and CPUC decisions on the transmission projects expected in the first half of 2016. ▪ Various phases expected to be placed in service

					starting in 2016 and continuing through 2019.
Sycamore-Peñasquitos Transmission Project ▪ 230-kV transmission project to provide 16.7-mile transmission connection between Sycamore Canyon and Peñasquitos substations. ▪ California ISO and state task force identified as necessary to ensure grid reliability given the closure of SONGS.	$ 120	to	$	150	▪ In March 2014, California ISO selected SDG&E in a competitively bid process to construct the project, which we originally estimated to cost $120 million to $150 million. ▪ September 2015 draft EIR/EIS recommends an alternative that undergrounds more of the project than originally proposed. The CPUC may consider this alternative, which has an estimated cost of $250 million to $300 million. ▪ CPUC decision expected in the first half of 2016, with the line expected to be in service in mid-2017.
South Orange County Reliability Enhancement ▪ 2012 application for Certificate of Public Convenience and Necessity (CPCN) to enhance the capacity and reliability of electric service to the south Orange County area. ▪ Replacing and upgrading approximately eight miles of transmission lines and rebuilding and upgrading a substation at an existing site.	$ 350	to	$	400	▪ Final CPUC decision expected in the first half of 2016. ▪ Planned in phases; entire project expected to be in service in 2020.
South Bay Substation and Relocation Project ▪ 2010 application with the CPUC for permit to construct new Bay Boulevard substation to replace the aging and obsolete South Bay substation. ▪ Demolish existing substation when the Bay Boulevard substation has been constructed, energized and all transmission lines have been transferred.	$ 145	to	$	175	▪ July 2014 petition filed with the CPUC requesting modifications to the prior CPUC decision to authorize additional construction activities required by the coastal development permit. ▪ CPUC approved the petition for modification in January 2015. Project expected to be in service in 2017.
Electric Vehicle Charging Program ▪ April 2014 proposal for program to build and own a total of 5,500 electric vehicle charging units at estimated cost of $103 million, of which $59 million is capital investment. ▪ Hourly Vehicle-to-Grid Integration rate to incent vehicle charging during times of the day that benefit the power grid.			$	45	▪ January 2016 CPUC final decision denies proposal but authorizes a 3-year, $45 million program providing up to 3,500 charging units.
Distribution Resource Plan ▪ July 2015 application filed with the CPUC submitting Distribution Resource Plan. Distributed energy resources (DER) are typically smaller power sources connected to the distribution grid and located near load centers.				TBD	▪ We expect the CPUC to address the Distribution Resource Plan in a phased manner with more than one decision issued in the 2016 to 2017 time period.

NOTE 12. COMMITMENTS AND CONTINGENCIES

LEGAL PROCEEDINGS

We accrue losses for a legal proceeding when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. However, the uncertainties inherent 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 amounts accrued, may exceed applicable insurance coverage and could materially adversely affect our business, cash flows, results of operations, financial condition and prospects. Unless otherwise indicated, we are unable to estimate reasonably possible losses in excess of any amounts accrued.

At December 31, 2015, accrued liabilities for legal proceedings were $26 million.

2007 Wildfire Litigation

In October 2007, San Diego County experienced several catastrophic wildfires. Reports issued by the California Department of Forestry and Fire Protection (Cal Fire) concluded that two of these 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' (Cox) fiber optic cable came into contact with an SDG&E power line "causing an arc and starting the fire." A September 2008 staff report issued by the CPUC's Consumer Protection and Safety Division, now known as the Safety and Enforcement Division, reached substantially the same conclusions as the Cal Fire reports, but also contended 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.

Numerous parties sued SDG&E and Sempra Energy in San Diego County Superior Court seeking recovery of unspecified amounts of damages, including punitive damages, from the three fires. They asserted various bases for recovery, including inverse condemnation based upon a California Court of Appeal decision finding that another California investor-owned utility was subject to strict liability, without regard to foreseeability or negligence, for property damages resulting from a wildfire ignited by power lines. We have resolved almost all of these lawsuits. One case remains subject to a damages-only trial, where the value of any compensatory damages resulting from the fires will be determined. Two appeals are pending after judgment in the trial court. We do not expect additional plaintiffs to file lawsuits given the applicable statutes of limitation, but could receive additional settlement demands and damage estimates from the remaining plaintiff until the case is resolved. We establish reserves for the wildfire litigation as information becomes available and amounts are estimable.

We have concluded that it is probable that it will be permitted to recover in rates a substantial portion of the costs incurred to resolve wildfire claims in excess of its liability insurance coverage and the amounts recovered from third parties. Accordingly, at December 31, 2015, we have recorded assets of $362 million in Other Regulatory Assets (long-term) on Balance Sheet, including $359 million related to CPUC-regulated operations, which represents the amount substantially equal to the aggregate amount it has paid and reserved for payment for the resolution of wildfire claims and related costs in excess of its liability insurance coverage and amounts recovered from third parties. On September 25, 2015, we filed an application with the CPUC seeking authority to recover these costs, as we discuss in Note 11. Should SDG&E conclude that recovery in rates is no longer probable, we will record a charge against earnings at the time such conclusion is reached. If we have concluded that the recovery of regulatory assets related to CPUC-regulated operations was no longer probable or was less than currently estimated at December 31, 2015, the resulting after-tax charge against earnings would have been up to approximately $213 million. A failure to obtain substantial or full recovery of these costs from customers, or any negative assessment of the likelihood of recovery, would likely have a material adverse effect on our results of operations and cash flows.

We provide additional information about excess wildfire claims cost recovery and related CPUC actions in Note 11 and discuss how we assess the probability of recovery of our regulatory assets in Note 1.

Smart Meters Patent Infringement Lawsuit

In October 2011, we were sued by a Texas design and manufacturing company in Federal District Court, Southern District of California, and later transferred to the Federal District Court, Western District of Oklahoma as part of Multi-District Litigation (MDL) proceedings, alleging that our recently installed smart meters infringed certain patents. The meters were purchased from a third party vendor that has agreed to defend and indemnify SDG&E. The lawsuit seeks injunctive relief and recovery of unspecified amounts of damages. The MDL court has finished ruling on pre-trial matters, and we expect that it will return the case to the Southern District of California.

Lawsuit Against Mitsubishi Heavy Industries , Ltd

On July18, 2013, we filed a lawsuit in the Superior Court of California in the County of San Diego against Mitsubishi Heavy Industries, Ltd., Mitsubishi Nuclear Energy Systems, Inc., and Mitsubishi Heavy Industries America, Inc. (collectively MHI). The lawsuit seeks to recover damages we have incurred and will incur related to the design defects in the steam generators MHI provided to the SONGS nuclear power plant. The lawsuit asserts a number of causes of action, including fraud, based on the representations MHI made about its qualifications and ability to design generators free from defects of the kind that resulted in the permanent shutdown of the plant and further seeks to set aside the contractual limitation of damages that MHI has asserted. On July 24, 2013, MHI removed the lawsuit to the United States District Court for the Southern District of California and on August 8, 2013, MHI moved to stay the proceeding pending resolution of the dispute resolution process involving MHI and Edison arising from their contract for the purchase and sale of the steam generators. On October 16, 2013, Edison initiated an arbitration proceeding against MHI seeking damages stemming from the failure of the replacement steam generators. In late December 2013, MHI answered and filed a counterclaim against Edison. On March 14, 2014, MHI’s motion to stay the United States District Court proceeding was granted with instructions that require the parties to allow SDG&E to participate in the ongoing Edison/MHI arbitration. As a result, we are is now participating in the arbitration as a claimant and respondent. Arbitration hearings are scheduled to begin in early 2016. We expect a decision by the end of 2016.

Investment in Wind Farm

In 2011, the CPUC and FERC approved our estimated $285 million tax equity investment in a wind farm project and its purchase of renewable energy credits from that project. Our contractual obligations to both invest in the Rim Rock wind farm and to purchase renewable energy credits from the wind farm under the power purchase agreement are subject to the satisfaction of certain conditions which, if not achieved, would allow SDG&E to terminate the power purchase agreement and not make the investment. In December 2013, we received a closing notice from the project developer indicating that all such conditions had been met. We responded to the closing notice asserting that the contractual conditions had not been satisfied. On December 19, 2013, we filed a complaint against the project developer in San Diego Superior Court, asking that the court determine that we are entitled to terminate both the investment contract and the power purchase agreement due to the project developer’s failure to satisfy certain conditions. The project developer filed a separate complaint against SDG&E in Montana state court asking that court to determine that we breached the investment contract and the power purchase agreement, and asking for several categories of relief, including requiring SDG&E to invest in the project, requiring SDG&E to continue performing under the power purchase agreement, and payment of damages.

On January 27, 2014, the Montana court ordered SDG&E to continue making payments under the power purchase agreement pending a hearing on the project developer’s preliminary injunction motion. On March 14, 2014, we notified the project developer that the investment agreement expired by its own terms because a closing had not occurred by that date. The project developer is disputing our position. On March 28, 2014, we filed an amended complaint against the project developer in San Diego seeking damages and declaratory relief that we were entitled to terminate the power purchase agreement and to permit the investment agreement to expire. On April 25, 2014, the Montana court granted the project developer’s preliminary injunction motion to prevent SDG&E from terminating the power purchase agreement on the grounds that the project developer would be irreparably harmed if the payments were not made while the parties’ respective rights were being determined in the litigation. The court did not rule on the merits of the parties’ claims. On July 18, 2014, the Montana Supreme Court determined that the parties’ contractual agreement to resolve any disputes in San Diego was mandatory, and ordered that the Montana action be dismissed. The San Diego court has scheduled a trial in May 2016. On February 11, 2016, SDG&E, the project developer and several of the project developer’s parent and affiliated entities entered into a conditional settlement agreement. Under the conditional settlement agreement, among other things, the parties agreed to terminate the tax equity investment arrangement, continue the power purchase agreement for the wind farm generation, and release all claims against each other. The conditional settlement agreement is not fully effective until approved by the CPUC.

Concluded Matter

In February 2011, opponents of the Sunrise Powerlink, a 500-kV electric transmission line between the Imperial Valley and the San Diego region that was energized and placed in service in June 2012, filed a lawsuit in Sacramento County Superior Court against the State Water Resources Control Board and SDG&E alleging that the water quality certification issued by the Board under the Federal Clean Water Act violated the California Environmental Quality Act. The Superior Court denied the plaintiffs’ petition in July 2012, and the plaintiffs appealed. On May 19, 2015 the California Court of Appeals affirmed the lower court’s decision and, on June 16, 2015, denied plaintiffs' request for rehearing. Plaintiffs did not seek review by the California Supreme Court within the prescribed time, so the Court of Appeals decision is final.

Natural Gas Contracts

SoCalGas has the responsibility for procuring natural gas for both SDG&E's and SoCalGas' core customers in a combined portfolio. For the years ended 2009 through 2015, we had no payments under natural gas contracts.

Purchased-Power Contracts

For 2016, we expect to meet its customer power requirements from the following resource types:

- Long-term contracts: 38 percent (of which 33 percent is provided by renewable energy contracts expiring on various dates through 2041)
- Other SDG&E-owned generation and tolling contracts (including OMEC): 56 percent
- Spot market purchases: 6 percent

At December 31, 2015, the estimated future minimum payments under long-term purchased-power contracts were:

FUTURE MINIMUM PAYMENTS – PURCHASED-POWER CONTRACTS
(Dollars in millions)

	SDG&E
2016	$ 521
2017	504
2018	502
2019	493
2020	430
Thereafter	6,071
Total minimum payments	$ 8,521

Payments on these contracts 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 at SDG&E, total payments under purchased-power contracts were:

PAYMENTS UNDER PURCHASED-POWER CONTRACTS
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
SDG&E(1)	$ 715	$ 710	$ 570

(1) Excludes DWR-allocated contracts. Under an operating agreement with the DWR that expired at the end of 2013, we acted 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 our customers. The commodity costs associated with these contracts are not included in our Statement of Operations.

Operating Leases

We have operating leases on real and personal property expiring at various dates from 2016 through 2054. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from two percent to five percent. 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.

We have an operating lease agreement for future acquisitions of fleet vehicles with an aggregate maximum lease limit of $150 million, $111 million of which has been utilized as of December 31, 2015.

Rent expense for operating leases is as follows:

RENT EXPENSE – OPERATING LEASES *(Dollars in millions)*	Years ended December 31,		
	2015	2014	2013
SDG&E	$ 27	$ 26	$ 23

At December 31, 2015, the minimum rental commitments payable in future years under all noncancelable operating leases were as follows:

FUTURE MINIMUM PAYMENTS – OPERATING LEASES *(Dollars in millions)*	
2016	$ 25
2017	25
2018	19
2019	18
2020	16
Thereafter	70
Total future minimum rental commitments	$ 173

Capital Leases

Power Purchase Agreements

We have four power purchase agreements with peaker plant facilities, one of which went into commercial operation in 2015. All four are accounted for as capital leases. At December 31, 2015, capital lease obligations for these leases, three with a 25-year term and one with a 9-year term, were valued at $243 million.

In the first quarter of 2015, we entered into a CPUC-approved 25-year power purchase agreement with a peaker plant facility that is currently under construction. Beginning with the initial delivery of the contracted power, scheduled in June 2017, the power purchase agreement will be accounted for as a capital lease.

The entities that own the peaker plant facilities are VIEs of which SDG&E is not the primary beneficiary. We do not have any additional implicit or explicit financial responsibility related to these VIEs.

At December 31, 2015, the future minimum lease payments and present value of the net minimum lease payments under these capital leases for SDG&E were as follows:

FUTURE MINIMUM PAYMENTS – POWER PURCHASE AGREEMENTS *(Dollars in millions)*	
2016	$ 39
2017	77
2018	104
2019	104
2020	104
Thereafter	1,910
Total minimum lease payments(1)	$ 2,338
Less: estimated executory costs	(523)
Less: interest(2)	(1,072)

Present value of net minimum lease payments(3)	$ 743

(1) This amount will be recorded over the lives of the leases as Cost of Electric Fuel and Purchased Power on SDG&E's Statement of Operations. This expense will receive ratemaking treatment consistent with purchased-power costs, which are recovered in rates.

(2) Amount necessary to reduce net minimum lease payments to present value at the inception of the leases.

(3) Includes $4 million in Current Portion of Long-Term Debt and $239 million in Long-Term Debt on SDG&E's Balance Sheet at December 31, 2015. Of the present value of net minimum lease payments, $500 million will be recorded as a capital lease obligation when construction of the peaker plant facility is completed and delivery of contracted power commences, which is scheduled to occur in June 2017.

The annual amortization charge for the power purchase agreements was $4 million in 2015, $3 million in 2014 and $2 million in 2013.

Other Capital Leases

We entered into agreements in 2009 and 2010 to refinance existing fleet vehicles. These capital leases concluded during 2015.

We entered into new capital leases during 2015 for additional fleet vehicles. At December 31, 2015, the related capital lease obligation was $1 million payable in 2016.

The annual depreciation charge for the fleet vehicles and other assets during 2015, 2014 and 2013 was $2 million, $2 million and $4 million, respectively.

Construction and Development Projects

At December 31, 2015, we have commitments to make future payments of $157 million for construction projects that include

- $61 million for the engineering, material procurement and construction costs primarily associated with the San Luis Rey Synchronous Condenser and Bay Boulevard Substation relocation projects;
- $18 million related to nuclear fuel fabrication and other construction projects at SONGS; and
- $78 million for infrastructure improvements for natural gas and electric transmission and distribution operations.

We expect future payments under these contractual commitments to be $67 million in 2016, $46 million in 2017, $12 million in 2018, $17 million in 2019, $5 million in 2020 and $10 million thereafter.

OTHER COMMITMENTS

In connection with the completion of the Sunrise Powerlink project in 2012, the CPUC required that we establish a fire mitigation fund to minimize the risk of fire as well as reduce the potential wildfire impact on residences and structures near the Sunrise Powerlink. The future payments for these contractual commitments are expected to be approximately $3 million per year, subject to escalation of 2 percent per year, for a remaining 54-year period. At December 31, 2015, the present value of these future payments of $117 million has been recorded as a regulatory asset as the amounts represent a cost that is expected to be recovered from customers in the future, and the related liability was $117 million.

In July 2012, we received $85 million from Citizens Sunrise Transmission, LLC (Citizens), a subsidiary of Citizens Energy Corporation. For this payment, under the terms of the agreement with Citizens, we will provide Citizens with access to a segment of the Sunrise Powerlink transmission line known as the Border-East transmission line equal to 50 percent of the transfer capacity of this portion of the line for a period of 30 years. After the 30-year contract term, the transfer capability will revert to SDG&E. We will amortize deferred revenues from the use of the transfer capability over the 30-year term, and depreciation for 50 percent of the Border-East transmission line segment will be accelerated from an estimated 58-year life to 30 years.

ENVIRONMENTAL ISSUES

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. Our costs to operate our facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Other Environmental Issues

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 our capital expenditures (including construction work in progress) in order to comply with environmental laws and regulations:

CAPITAL EXPENDITURES FOR ENVIRONMENTAL ISSUES
(Dollars in millions)

	Years ended December 31,		
	2015	2014	2013
SDG&E	$ 24	$ 23	$ 13

Fluctuations from 2013 to 2014 were primarily due to increased project activities during 2014, including PSEP-related projects.

Our 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 our manufactured-gas sites, (2) cleanup of third-party waste-disposal sites used by us at sites for which we have been identified as a PRP 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 pr6ocess and include a 150-acre artificial reef that was dedicated in 2008 and continues in process to meet California Coastal Commission (CCC) acceptance requirements. It is anticipated that the CCC will require expansion of the reef, as the existing reef may be too small to consistently meet the performance standard. The table below shows the status at December 31, 2015, of our manufactured-gas sites and the third-party waste-disposal sites for which we have been identified as a PRP:

STATUS OF ENVIRONMENTAL SITES

	# Sites completed(1)	# Sites in process
Manufactured-gas sites	3	-
Third-party waste-disposal sites	2	1

(1) There may be on-going compliance obligations for completed sites, such as regular inspections, adherence to land use covenants and water quality monitoring.

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 cleanups proceed, we make adjustments as necessary. The following table shows our accrued liabilities for environmental matters at December 31, 2015:

ACCRUED LIABILITIES FOR ENVIRONMENTAL MATTERS
(Dollars in millions)

	Manufactured-gas sites	Waste disposal sites (PRP)(1)	Former fossil-fueled power plants	Other hazardous waste sites	Total(2)
SDG&E(3)	$ -	$ 0.9	$ 0.7	$ 0.5	$ 2.1

(1) Sites for which we have been identified as a Potentially Responsible Party.
(2) We have accrued $2 million for environmental liabilities as of December 31, 2015. Of this amount, $1 million was classified as current liabilities, and $1 million was classified as noncurrent liabilities on our Balance Sheet.
(3) Does not include our liability for SONGS marine mitigation.

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 CCC to mitigate the damage to the marine environment caused by the cooling-water discharge from SONGS during its operation. SONGS' early retirement, described in Note 10, does not reduce our mitigation obligation. At December 31, 2015, our share of the estimated mitigation costs remaining to be spent through 2050 is $14 million, which is recoverable in rates and included in Deferred Credits and Other Liabilities on our Balance Sheet.

We discuss renewable energy requirements in Note 11 and greenhouse gas regulation in Note 1.

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 $375 million in coverage limits, the maximum amount available, including coverage for acts of terrorism. In addition, the Price-Anderson Act provides for up to $13.2 billion of secondary financial protection (SFP). If a nuclear liability loss occurring at any U.S. licensed/commercial reactor exceeds the $375 million insurance limit, all nuclear reactor owners could be required to contribute to the SFP. Our contribution would be up to $50.93 million. This amount is subject to an annual maximum of $7.6 million, unless a default occurs by any other SONGS owner. If the SFP is insufficient to cover the liability loss, we 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, subject to a $2.5 million deductible for "each and every loss." This insurance coverage is provided through Nuclear Electric Insurance Limited (NEIL). The NEIL policies have specific exclusions and limitations that can result in reduced or eliminated coverage. Insured members as a group are subject to retrospective premium assessments to cover losses sustained by NEIL under all issued policies. SDG&E could be assessed up to $9.7 million of retrospective premiums based on overall member claims. See Note 10 under "Settlement with NEIL" for discussion of an agreement between the SONGS co-owners and NEIL to settle all claims under the NEIL policies associated with the SONGS outage.

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.

U.S DEPARTMENT OF ENERGY (DOE) 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. SDG&E will seek recovery for these costs from the appropriate sources, including, but not limited to, SDG&E's Nuclear Decommissioning Trusts. We will also continue to support Edison in its pursuit of legal claims on behalf of the SONGS co-owners against the DOE for its failure to timely accept the spent nuclear fuel.

In October 2015, the CCC approved Edison's application for the proposed expansion of an Independent Spent Fuel Storage Installation (ISFSI) at SONGS. The ISFSI is proposed to be installed beginning in 2016, fully loaded with spent fuel by 2020, and operated until 2049, when it is assumed that the DOE will have taken custody of all the SONGS spent fuel. The facility would then be decommissioned, and the site restored.

In June 2010, the United States Court of Federal Claims issued a decision granting Edison and the SONGS co-owners damages of approximately $142 million to recover costs incurred through December 31, 2005 for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from SONGS. Edison received payment from the federal government in the amount of the damage award in November 2011. In January 2012, Edison refunded SDG&E $28 million for its respective share of the damage award paid. SDG&E recorded a $10 million reduction of nuclear power expenses, a $15 million reduction of its nuclear decommissioning balancing account and a $3 million reduction in nuclear plant. Edison, as operating agent, filed a lawsuit against the DOE in the Court of Federal Claims in December 2011 seeking damages of $98 million for the period from January 1, 2006 to December 31, 2010 for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel. In September 2014, Edison updated the claim to include another $84 million for costs incurred from January 2011 to December 2013.

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.

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	/ /	End of 2015/Q4

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.
4. Report data on a year-to-date basis.

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		(9,009,678)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(2,988,348)		
4	Total (lines 2 and 3)		(2,988,348)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(11,998,026)		
6	Balance of Account 219 at Beginning of Current Year		(11,998,026)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		4,157,712		
9	Total (lines 7 and 8)		4,157,712		
10	Balance of Account 219 at End of Current Quarter/Year		(7,840,314)		

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			(9,009,678)		
2					
3			(2,988,348)		
4			(2,988,348)	507,250,700	504,262,352
5			(11,998,026)		
6			(11,998,026)		
7					
8			4,157,712		
9			4,157,712	584,687,607	588,845,319
10			(7,840,314)		

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	/ /	End of 2015/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 (h) 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)	14,610,657,801	12,012,937,207
4	Property Under Capital Leases	873,012,337	852,823,281
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	15,483,670,138	12,865,760,488
9	Leased to Others	85,194,000	85,194,000
10	Held for Future Use	11,307,728	11,307,728
11	Construction Work in Progress	923,122,087	686,185,400
12	Acquisition Adjustments	3,750,722	3,750,722
13	Total Utility Plant (8 thru 12)	16,507,044,675	13,652,198,338
14	Accum Prov for Depr, Amort, & Depl	5,361,217,298	4,161,336,003
15	Net Utility Plant (13 less 14)	11,145,827,377	9,490,862,335
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,812,199,292	3,848,087,212
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	536,549,965	300,780,750
22	Total In Service (18 thru 21)	5,348,749,257	4,148,867,962
23	Leased to Others		
24	Depreciation	11,467,849	11,467,849
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	11,467,849	11,467,849
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	1,000,192	1,000,192
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,361,217,298	4,161,336,003

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
1,641,760,399				955,960,195	3
				20,189,056	4
					5
					6
					7
1,641,760,399				976,149,251	8
					9
					10
159,593,889				77,342,798	11
					12
1,801,354,288				1,053,492,049	13
714,699,112				485,182,183	14
1,086,655,176				568,309,866	15
					16
					17
706,555,900				257,556,180	18
					19
					20
8,143,212				227,626,003	21
714,699,112				485,182,183	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
714,699,112				485,182,183	33

Schedule Page: 200 Line No.: 4 Column: b

Description	Capital leases	ITD Depreciation	Capital lease obligations
Otay Mesa Energy Center (OMEC)	595,400,000	(168,060,255)	427,339,745
Orange Grove	123,238,342	(6,647,613)	116,590,729
El Cajon Energy	59,751,923	(5,823,608)	53,928,315
Escondido	59,549,016	(1,609,275)	57,939,741
Fleet	20,189,056	(19,590.319)	598,737
Yuma	14,884,000	(15,394)	14,868,606
	873,012,337	(201,746,464)	671,265,873

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

Reclassification of 2015 Accum. Provision for Depreciation & Amortization for Ratemaking

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

	Accumulated Provision
Electric	
Intangible Plant	61,005,254
Steam Production Plant	194,692,780
Other Production Plant	178,701,651
Transmission Plant	848,040,689
Distribution Plant	2,538,004,681
General Plant	124,471,323
Ratemaking Electric	3,944,916,378
Nuclear Decommissioning	910,691,580
ASC 410 (FAS 143 and FIN 47) - Electric	(905,751,696)
Capital Leases A/D	182,156,145
Leased to Others- Citizens A/D	11,467,849
Cuyamaca Permanent Adjustment	17,855,747
Total Electric	4,161,336,003
Ratemaking Gas	924,302,397
FIN 47 - Gas	(209,603,285)
Total Gas	714,699,112
Ratemaking Common	465,617,932
FIN 47 - Common	(26,068)
Fleet Capital Lease A/D	19,590,319
Total Common	485,182,183
Total Accumulated Provision 2015	5,361,217,298

Total 13-Month Average Accum. Provision for 2015 -Steam Production	185,123,622
Total 13-Month Average Accum. Provision for 2015 -Nuclear Production	-
Total 13-Month Average Accum. Provision for 2015 -Other Production	169,259,892
Total 13-Month Average Accum. Provision for 2015 -Transmission Plant	795,744,965

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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		
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)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
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)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
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)		

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	/ /	End of 2015/Q4

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
			2
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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	130,236,074	13,950,440
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	130,458,915	13,950,440
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	94,085,697	1,132,067
10	(312) Boiler Plant Equipment	166,495,949	80,673
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	131,183,790	232
13	(315) Accessory Electric Equipment	82,187,084	3,452,542
14	(316) Misc. Power Plant Equipment	43,270,083	2,127,116
15	(317) Asset Retirement Costs for Steam Production	1,379,851	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	533,128,972	6,792,630
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
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	199,508	
38	(341) Structures and Improvements	22,748,227	
39	(342) Fuel Holders, Products, and Accessories	20,975,581	
40	(343) Prime Movers	96,528,238	482,076
41	(344) Generators	342,654,338	-1,065,854
42	(345) Accessory Electric Equipment	33,384,957	
43	(346) Misc. Power Plant Equipment	24,606,994	
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	541,097,843	-583,778
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,074,226,815	6,208,852

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	215,800,678	6,473,024
49	(352) Structures and Improvements	380,558,417	32,425,262
50	(353) Station Equipment	1,150,023,892	120,188,475
51	(354) Towers and Fixtures	846,803,951	48,831,794
52	(355) Poles and Fixtures	361,276,604	73,123,575
53	(356) Overhead Conductors and Devices	505,662,719	41,583,384
54	(357) Underground Conduit	329,312,148	6,044,656
55	(358) Underground Conductors and Devices	338,228,280	16,718,059
56	(359) Roads and Trails	295,740,845	14,632,775
57	(359.1) Asset Retirement Costs for Transmission Plant	6,773,223	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,430,180,757	360,021,004
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	98,162,318	1,616,381
61	(361) Structures and Improvements	4,018,870	-71
62	(362) Station Equipment	465,807,804	9,852,518
63	(363) Storage Battery Equipment	6,892,564	30,743,932
64	(364) Poles, Towers, and Fixtures	590,295,852	57,766,235
65	(365) Overhead Conductors and Devices	467,119,213	86,823,007
66	(366) Underground Conduit	1,055,883,303	52,047,726
67	(367) Underground Conductors and Devices	1,372,231,927	60,904,390
68	(368) Line Transformers	560,502,477	41,506,541
69	(369) Services	455,543,138	14,821,208
70	(370) Meters	245,878,185	3,984,603
71	(371) Installations on Customer Premises	7,827,825	180,791
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	26,550,715	1,604,749
74	(374) Asset Retirement Costs for Distribution Plant	8,025,670	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,364,739,861	361,852,010
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	7,312,143	
87	(390) Structures and Improvements	32,473,669	691,655
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	58,146	
90	(393) Stores Equipment	15,720	
91	(394) Tools, Shop and Garage Equipment	22,773,324	1,793,833
92	(395) Laboratory Equipment	2,147,777	3,009,036
93	(396) Power Operated Equipment	60,529	
94	(397) Communication Equipment	235,288,025	11,836,475
95	(398) Miscellaneous Equipment	1,515,803	3,074,684
96	SUBTOTAL (Enter Total of lines 86 thru 95)	301,645,136	20,405,683
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)	301,645,136	20,405,683
100	TOTAL (Accounts 101 and 106)	11,301,251,484	762,437,989
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)	11,301,251,484	762,437,989

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	/ /	End of 2015/Q4

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
			144,186,514		4
			144,409,355		5
					6
					7
			14,526,518		8
			95,217,764		9
			166,576,622		10
					11
			131,184,022		12
			85,639,626		13
		-2,041,970	43,355,229		14
			1,379,851		15
		-2,041,970	537,879,632		16
					17
					18
					19
					20
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			199,508		37
			22,748,227		38
			20,975,581		39
			97,010,314		40
	1,026,795		342,615,279		41
			33,384,957		42
28,535		2,041,970	26,620,429		43
					44
28,535	1,026,795	2,041,970	543,554,295		45
28,535	1,026,795		1,081,433,927		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	/ /	End of 2015/Q4

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
9,439	7,945	1,785,268	224,057,476		48
349,819		-163,665	412,470,195		49
3,830,106		-697,719	1,265,684,542		50
			895,635,745		51
3,590,921	262,700		431,071,958		52
168,070			547,078,033		53
			335,356,804		54
465,316			354,481,023		55
			310,373,620		56
	-6,720,355		52,868		57
8,413,671	-6,449,710	923,884	4,776,262,264		58
					59
4,691	966		99,774,974		60
26,194		163,665	4,156,270		61
1,065,926		-327,454	474,266,942		62
			37,636,496		63
9,726,369	396,423		638,732,141		64
1,432,361	699,349		553,209,208		65
3,035,487	1,348,136		1,106,243,678		66
8,858,656	19,128		1,424,296,789		67
6,683,981			595,325,037		68
2,150,670	1,785		468,215,461		69
985,814			248,876,974		70
21,462			7,987,154		71
					72
140,641			28,014,823		73
	-5,945,498		2,080,172		74
34,132,252	-3,479,711	-163,789	5,688,816,119		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			7,312,143		86
657,531			32,507,793		87
					88
			58,146		89
7,174			8,546		90
156,665			24,410,492		91
3,975			5,152,838		92
			60,529		93
241,376	6,272	1,025,172	247,914,568		94
			4,590,487		95
1,066,721	6,272	1,025,172	322,015,542		96
					97
					98
1,066,721	6,272	1,025,172	322,015,542		99
43,641,179	-8,896,354	1,785,267	12,012,937,207		100
					101
					102
					103
43,641,179	-8,896,354	1,785,267	12,012,937,207		104

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

Reclassification of 2015 Electric Plant-in-Service for Ratemaking

Plant in Service Classified under FERC Seven Factor Test

In Accordance with Guidelines in FERC Order 888

	BOY 2015	EOY 2015
Intangible Plant	130,236,073	144,186,514
Steam Production Plant	546,022,555	550,778,966
Nuclear Production Plant	-	-
Other Production Plant	485,750,987	485,990,944
Transmission Plant	4,367,504,895	4,715,038,439
Distribution Plant	5,439,808,068	5,777,308,886
General Plant	301,645,135	322,015,542
Ratemaking Electric	11,270,967,714	11,995,319,291
ASC 410 (FAS 143 and FIN 47)	16,178,745	3,512,891
Cuyamaca Permanent Adjustment	14,105,025	14,105,025
Total Electric Plant-in-Service	11,301,251,484	12,012,937,207

Total 13-Month Average Plant Balance for 2015 - Steam Production	548,493,072
Total 13-Month Average Plant Balance for 2015 - Nuclear Production	0
Total 13-Month Average Plant Balance for 2015 - Other Production	485,944,006
Total 13-Month Average Plant Balance for 2015 - Transmission Plant	4,574,357,640

* As a result of the SONGS plant closure, the December 2015 Nuclear Production Plant Balance is zero.

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	/ /	End of 2015/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	Citizens Sunrise Transmission LLC	117 mile-500KV Transmission Line	ER12-	7-02-2042	85,194,000
2		(Border-East Line)	686-000		
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47	TOTAL				85,194,000

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	/ /	End of 2015/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	Salt Creek	7/31/2011	4/1/2016	6,005,098
4				
5	Oceanside	5/31/2012	5/1/2016	360,835
6				
7	Ocean Ranch	3/31/2013	1/1/2018	4,941,795
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
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47	Total			11,307,728

Schedule Page: 214 Line No.: 46 Column: d

The 13-Month Average Electric Transmission Plant Held for Future Use is $5,859,856.

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	/ /	End of 2015/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 $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SOLAR PHOTOVOLTAIC INITIATIVE	2,990,223
2	TRANSMISSION PROJECTS UNDER $500K	14,954,568
3	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	2,441,529
4	SUNNYSIDE SUBSTATION 69/12KV REBUILD	14,316,552
5	CRITICAL ASSET SECURITY	18,064,082
6	TL663 MISSION-KEARNY RECONDUCTOR	1,318,236
7	TL13828 RELOCATION *	-1,653,976
8	IMPERIAL VALLEY SUBSTATION FLOW CONTROLLER	11,160,831
9	SYCAMORE-PENASQUITOS NEW 230KV TIE LINE	26,654,092
10	ARTESIAN 230KV SUBSTATION EXPANSION	1,699,860
11	ORANGE COUNTY LONG RANGE PLAN	33,779,256
12	SAN ONOFRE SUBSTATION SERVICE TRANSFORMERS	2,009,912
13	SAN LUIS REY SUBSTATION - SYNCHRONOUS CONDENSERS	78,813,645
14	TALEGA SUBSTATION - SYNCHRONOUS CONDENSERS	9,669,267
15	MIGUEL SUBSTATION 500KV VOLTAGE SUPPORT	4,840,435
16	SOUTH BAY SUBSTATION RELOCATION	87,753,295
17	TL6926 RINCON-VALLEY CENTER POLE REPLACEMENT	6,235,100
18	SCADA EXPANSION - TRANSMISSION	1,025,308
19	MESA 230KV SUBSTATION	27,112,238
20	IMPERIAL VALLEY SUBSTATION SECURITY	4,781,828
21	SUNCREST SUBSTATION - 500KV SHUNT REACTOR	1,945,977
22	TL628 CABLE REPLACEMENT	2,828,640
23	LOS COCHES SUBSTATION REBUILD	15,317,148
24	WABASH SUBSTATION REBUILD	9,457,448
25	TL649 POLE REPLACEMENT	2,565,256
26	SYNCHRONIZED PHASOR MEASUREMENT SYSTEM	6,751,406
27	TL615/659 CABLE REPLACEMENT	1,852,825
28	TL633 RECONDUCTOR	1,526,782
29	CONDITION BASED MONITORING - CIRCUIT BREAKERS	3,549,357
30	MERCHANT SWITCHYARD	14,458,481
31	ENCINA SUBSTATION - INSTALL BANK 61	8,498,859
32	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	11,453,026
33	SUBSTATION MONITORING EQUIPMENT - TRANSMISSION	1,192,929
34	TRANSMISSION INFRASTRUCTURE IMPROVEMENTS	12,857,276
35	TL695 SW POLE REPLACEMENT	1,712,648
36	TL676 MISSION - MESA HEIGHTS RECONDUCTOR	1,326,124
37	PIO PICO ENERGY CENTER INTERCONNECTION	9,038,898
38	AERIAL MARKING FOR SAFETY	1,283,507
39	SUBSTATION SECURITY INSTALLATIONS	4,593,851
40	TL629 SW POLE REPLACEMENTS	30,349,016
41	TL13821 & TL13828 JUNCTION ENHANCEMENT	4,794,271
42	138KV & 69KV CIRCUIT BREAKER UPGRADES	3,771,489
43	TOTAL	686,185,400

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	/ /	End of 2015/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 $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	TRANSMISSION SYSTEM AUTOMATION	1,877,374
2	DISTRIBUTION SUBSTATION RELIABILITY	1,789,313
3	CONVERSION FROM OH TO UG RULE 20A	19,926,446
4	CITY OF SAN DIEGO SURCHARGE PROGRAM	2,400,988
5	UG RESIDENTIAL NEW BUSINESS	3,019,465
6	UG NON-RESIDENTIAL NEW BUSINESS	1,813,404
7	CUSTOMER REQUESTED UPGRADES & SERVICES *	-1,125,469
8	OH DISTRIBUTION SERVICE MANAGEMENT	1,787,389
9	CORRECTIVE MAINTENANCE PROGRAM	1,590,693
10	REPLACEMENT OF UNDERGROUND CABLES	1,591,905
11	WOOD POLE REINFORCEMENT	4,088,718
12	LOAD INTEGRATION CAPACITY ANALYSIS	1,520,543
13	DISTRIBUTION PHASOR MEASUREMENT UNITS	12,464,014
14	KETTNER SUBSTATION REBUILD	2,699,218
15	BORREGO SPRINGS MICROGRID ENHANCEMENTS	4,115,544
16	ADVANCED GROUND FAULT DETECTION	1,935,636
17	SMART ISOLATION & RECLOSING EQUIPMENT	1,125,720
18	FIRE HAZARD PREVENTION	12,271,559
19	DISTRIBUTION SYSTEM CAPACITY IMPROVEMENT	1,981,999
20	ADVANCED WEATHER STATION INTEGRATION	2,840,175
21	OCEAN RANCH LAND PURCHASE	1,400,808
22	SUBSTATION CAPACITOR BANK UPGRADES	5,972,233
23	CIVITA MICROGRID	1,432,483
24	JAMUL SUBSTATION	1,217,001
25	SALT CREEK SUBSTATION	7,771,787
26	CIRCUIT C1243 RECONDUCTOR	1,739,175
27	SEWAGE PUMP STATION REBUILDS	5,161,620
28	NEW 12KV CIRCUIT C1090	13,194,915
29	DISTRIBUTED GENERATION INTERCONNECTION PROJECTS *	-1,396,820
30	CONDITION BASED MONITORING - SMART GRID	1,331,259
31	SCADA EXPANSION - DISTRIBUTION	3,578,236
32	POINT LOMA SUBSTATION - INSTALL 3RD BANK	6,015,932
33	MIDDLETOWN SUBSTATION REMOVAL	1,037,222
34	MASTER METER MOBILE HOME PARK TRANSFERS	3,198,027
35	OBSOLETE SUBSTATION EQUIPMENT REPLACEMENT	1,339,741
36	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLAC. & MANHOLE REPAIR	5,518,052
37	SMART GRID ANOMALY DETECTION	8,859,927
38	DEMAND RESPONSE MANAGEMENT SYSTEM	3,378,260
39	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	12,256,283
40	MINOR PROJECTS (LESS THAN $1,000,000)	24,373,130
41	RESEARCH, DEVELOPMENT & DEMONSTRATION	
42		
43	TOTAL	686,185,400

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 $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ANNUAL CHANGES IN PROJECT BALANCES ARE DUE TO COMPLETION OF	
2	OF SEPARATE SEGMENTS OF THE BUDGET.	
3		
4	* CUSTOMER CONTRIBUTION IN AID OF CONSTRUCTION EXCEEDS	
5	PROJECT COSTS TO DATE.	
6		
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42		
43	TOTAL	686,185,400

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	3,568,220,011	3,568,220,011		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	380,141,688	380,141,688		
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)	380,141,688	380,141,688		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	43,627,049	43,627,049		
13	Cost of Removal	54,297,912	54,297,912		
14	Salvage (Credit)	5,343,338	5,343,338		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	92,581,623	92,581,623		
16	Other Debit or Cr. Items (Describe, details in footnote):	-76,486,202	-76,486,202		
17					
18	Book Cost or Asset Retirement Costs Retired	68,793,338	68,793,338		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,848,087,212	3,848,087,212		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	197,011,478	197,011,478		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	187,269,933	187,269,933		
25	Transmission	861,039,182	861,039,182		
26	Distribution	2,478,295,295	2,478,295,295		
27	Regional Transmission and Market Operation				
28	General	124,471,324	124,471,324		
29	TOTAL (Enter Total of lines 20 thru 28)	3,848,087,212	3,848,087,212		

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

Depreciation Provision - Electric only (Line 3, Col. C, Page 219)	$ 380,141,688
Depreciation Provision - Common Alloc. to Elec. (Line 11, pg 336)	25,309,844
Depreciation Provision - (Line 6, Col. G, Page 115)	$ 405,451,532
	=============

Schedule Page: 219 Line No.: 13 Column: c

Book Cost of Plant Retired (Line 12, Col. C, Page 219)	$(43,627,049)
Total Plant Retired (Line 104, Col. D, Page 207	43,641,179
Adj. for Land & Intangible Retirements not impacting A/C 108	(14,130)
Difference:	$ 0
	=============

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

SONGS Decommissioning - Current Year Trust Income (Loss)	$(77,476,623)
Transfer of Reserves between asset classes	990,421
Other Debit and Credit Items (Line 16, Col. C, Page 219	$(76,486,202)
	=============

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	/ /	End of 2015/Q4

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				
2				
3				
4				
5				
6				
7				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

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
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				10
				11
				12
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Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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)	7,521,721	5,493,301	
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)	5,891,440	6,104,647	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	6,765,202	7,048,895	ELECTRIC/GAS
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	87,717,276	91,429,468	ELECTRIC/GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	100,373,918	104,583,010	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
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)	107,895,639	110,076,311	

Schedule Page: 227 Line No.: 12 Column: c

Reclassification of FERC Form 1 2015 Materials & Supplies, Page 227, for Ratemaking

Materials and Supplies Classified

In accordance with Guidelines in FERC Order 888

	BOY 2015	EOY 2015
Total Materials and Supplies (FERC 154)	100,373,918	104,583,010 1
As Assigned to Department for Ratemaking		
Electric Department	97,122,143	101,319,984
Gas Department	3,251,775	3,263,026
Less Line 5 (Construction Estimate)		
Electric Department	(5,683,344)	(5,787,452)
Gas Department	(208,096)	(317,195)
Total Allowable Materials and Supplies		
Electric Department	91,438,799	95,532,532
Gas Department	3,043,679	2,945,831
Total Allowable Materials and Supplies per FERC Formula	94,482,478	98,478,363 2
Total 13-Month Average Electric M&S for 2015	71,777,703	91,724,081

1 Ties to Line 12 of FERC Form 1, pages 227

2 Ties to Line 12 minus Line 5 of FERC Form 1, pages 227

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	/ /	End of 2015/Q4

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.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	66,989.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	12,947.00		12,947.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Transfers to Palomar	-6.00			
10	Transfers to Miramar	2.00			
11	Transfers to Cuyamaca	2.00			
12	Transfers to Desert Str	-5.00			
13					
14					
15	Total	-7.00			
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	79,929.00		12,947.00	
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				

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	/ /	End of 2015/Q4

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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						66,989.00		1
								2
								3
12,947.00		12,947.00		349,569.00		401,357.00		4
								5
								6
								7
								8
						-6.00		9
						2.00		10
						2.00		11
						-5.00		12
								13
								14
						-7.00		15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
12,947.00		12,947.00		349,569.00		468,339.00		29
								30
								31
								32
								33
								34
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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	/ /	End of 2015/Q4

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.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
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				
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.

2017		2018		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
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								46

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					

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	SONGS Plant Shutdown Project	308,080,681		Various	50,561,244	257,519,437
22	Electric Legacy Meters Project	47,110,150		407	14,922,162	32,187,988
23	Sycamore-Bernardo Project	1,366,481				1,366,481
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
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35						
36						
37						
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43						
44						
45						
46						
47						
48						
49	TOTAL	356,557,312			65,483,406	291,073,906

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	/ /	End of 2015/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					
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19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
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31					
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33					
34					
35					
36					
37					
38					
39					
40					

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	/ /	End of 2015/Q4

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 $100,000 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 (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Taxes Recoverable in Rates	867,568,705	82,629,769	182.2	3,223,408	946,975,066
2	Amortized Over Various Lives					
3						
4	Post Retirement Benefits Other Than Pension	35,922,067	7,357,561	228	38,885,379	4,394,249
5						
6	Workers Compensation (IBNR)	1,528,764	2,605,818	186 / 228	4,134,582	
7						
8	Employer's Accounting for Postemplyment Benefits	4,743,000	775,000			5,518,000
9						
10	Environmental Clean-Up	6,728,716	14,273,604	242 / 253	19,048,922	1,953,398
11						
12	Balancing Account Undercollections	1,480,005,102		456 / 495	419,163,163	1,060,841,939
13						
14	Pension Benefits	135,377,805	49,196,659	228	8,671,688	175,902,776
15						
16	SONGS Mitigation	19,921,800		253	6,101,293	13,820,507
17						
18	Electric Derivatives	185,364,888	1,681,854,279	175 / 244	1,691,500,999	175,718,168
19						
20	Gas Derivatives	1,249,327	4,628,167	244	5,877,494	
21						
22	Contribution to City of Escondido	1,716,240	81,574	253	200,000	1,597,814
23	(20 year life, starting 2006)					
24						
25	Asset Retirement Obligations	19,607,260	2,923,982	230	1,796,051	20,735,191
26						
27	2007 Excess Wildfire Claims	373,059,163	84,482,714	456	94,162,931	363,378,946
28						
29	Sunrise Wildfire Mitigation	116,063,121	7,579,327	563	6,593,316	117,049,132
30						
31	Beyond The Meter		197,997			197,997
32						
33						
34						
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42						
43						
44	TOTAL	3,248,855,958	1,938,586,451		2,299,359,226	2,888,083,183

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	/ /	End of 2015/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 $100,000, 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	487,966	712,000	181	324,305	875,661
2						
3	Southwest Powerlink Deferred					
4	per CPUC					
5	(amortization 1/86 - 12/23)	379,498		406	15,744	363,754
6						
7	Mitigation Fund	260,702		186	110,374	150,328
8						
9	Solar Photovoltaic	2,985,574		107	2,985,574	
10						
11	Campo Wind Farm Project	305,580				305,580
12						
13	Invenergy Cost Sharing	729,406				729,406
14						
15	Long-Term Purch Power Rcvble	12,495,975				12,495,975
16						
17	Invenergy Wind Development	238,525				238,525
18						
19	Environmental Program	642,073	6,543,237			7,185,310
20						
21	Oracle Costs	1,154,726	20,000	118	127,880	1,046,846
22						
23	Worker Comp Receivable	7,644,044	511,631			8,155,675
24						
25	SONGS Decommissioning	961,049	22,950,160	228	21,714,616	2,196,593
26						
27	Pendleton Energy Park	195,734				195,734
28						
29	Gaskell Tax Equity	203,274				203,274
30						
31	Supervisory Control & Data	1,166,114	613,428	368	1,039,560	739,982
32	Acquisition Equipment					
33						
34	Fenton Land Rights		157,984			157,984
35						
36	Miscellaneous Other	164,478		various	5,242	159,236
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	30,014,718				35,199,863

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	/ /	End of 2015/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	418,198,814	167,867,763
3	State	70,940,947	76,611,001
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	489,139,761	244,478,764
9	Gas		
10	Federal	23,143,657	15,849,819
11	State	-2,226,655	3,486,769
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	20,917,002	19,336,588
17	Other (Specify) Non-Utiltity	81,302,217	12,232,420
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	591,358,980	276,047,772

Notes

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

Electric balance in Account 190 at the end of the year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $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	/ /	End of 2015/Q4

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	255,000,000	2.50	
2				
3	Preferred Stock	45,000,000		
4				
5				
6				
7	Note: All the Common Stock of San Diego Gas &			
8	Electric is owned by Enova Corporation and is			
9	not publicly traded.			
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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
						2
						3
						4
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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	/ /	End of 2015/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	Asset Transferred from Sempra Energy	79,665,369
9	Equity infusion from Enova Corporation	400,000,000
10	Total Account 211	479,665,369
11		
12		
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40	TOTAL	479,665,369

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	/ /	End of 2015/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		
4		
5		
6		
7		
8		
9		
10		
11		
12		
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14		
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21		
22	TOTAL	24,605,640

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	/ /	End of 2015/Q4

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	ACCOUNT 221-BONDS		
2			
3	FIRST MORTGAGE BONDS		
4	5.00% and 5.25% Series OO Due 2027	250,000,000	1,615,079
5			
6	5.875% Series VV Due 2034	43,615,000	1,509,414
7			
8	5.875% Series WW Due 2034	40,000,000	1,385,317
9			
10	5.875% Series XX Due 2034	35,000,000	1,213,328
11			
12	5.875% Series YY Due 2034	24,000,000	832,448
13			
14	5.875% Series ZZ Due 2034	33,650,000	1,165,922
15			
16	4.000% Series AAA Due 2039	75,000,000	3,089,247
17			
18	5.35% Series BBB Due 2035	250,000,000	2,709,950
19			295,000 D
20	5.30% Series CCC Due 2015	250,000,000	2,088,966
21			497,500 D
22	6.00% Series DDD Due 2026	250,000,000	2,429,000
23			1,117,500 D
24	1.650% Series EEE Due 2018	161,240,000	4,375,665
25			
26	6.125% Series FFF Due 2037	250,000,000	2,556,327
27			780,000 D
28	6.000% Series GGG Due 2039	300,000,000	3,057,571
29			1,380,000 D
30	5.350% Series HHH Due 2040	250,000,000	2,486,955
31			335,000 D
32	4.500% series III Due 2040	500,000,000	5,044,008
33	TOTAL	4,680,055,000	64,467,882

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	/ /	End of 2015/Q4

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			5,515,000 D
2	3.000% Series JJJ Due 2021	350,000,000	2,775,568
3			1,795,500 D
4	3.950% Series LLL Due 2041	250,000,000	2,639,787
5			350,000 D
6	4.300% Series MMM Due 2042	250,000,000	2,569,738
7			1,297,500 D
8	3.600% Series NNN Due 2023	450,000,000	3,670,004
9			72,000 D
10	0.4677% Series OOO Due 2017	140,000,000	439,916
11			
12	1.914% Series PPP Due 2022	250,000,000	1,715,986
13			
14	TOTAL ACCOUNT 221	4,402,505,000	62,805,196
15			
16	ACCOUNT 222-REACQUIRED BONDS-NONE		
17			
18	ACCOUNT 223-ADVANCES FROM ASSOCIATED COMPANIES-NONE		
19			
20	ACCOUNT 224-OTHER LONG TERM DEBT		
21			
22	Unsecured Bonds-5.3% Series CV96A	38,900,000	568,876
23			
24	Unsecured Bonds-5.5%-Series CV96B	60,000,000	680,090
25			
26	Unsecured Bonds-4.9% Series CV97A	25,000,000	386,466
27			
28	Long Term Commercial Paper, 0.4%	100,000,000	
29			
30	Long Term Commercial Paper, 1.05%	53,650,000	27,254
31			
32	SUBTOTAL ACCOUNT 224	277,550,000	1,662,686
33	TOTAL	4,680,055,000	64,467,882

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)	AMORTIZATION PERIOD 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
12/01/92	12/01/27	12/01/92	12/01/27	105,000,000	6,798,750	4
						5
06/17/04	02/15/34	06/17/04	02/15/34	43,615,000	2,562,381	6
						7
06/17/04	02/15/34	06/17/04	02/15/34	40,000,000	2,350,000	8
						9
06/17/04	02/15/34	06/17/04	02/15/34	35,000,000	2,056,250	10
						11
06/17/04	01/01/34	06/17/04	01/01/34	24,000,000	1,410,000	12
						13
06/17/04	01/01/34	06/17/04	01/01/34	33,650,000	1,976,937	14
						15
06/17/04	05/01/39	06/17/04	05/01/39	75,000,000	3,000,000	16
						17
05/19/05	05/15/35	05/19/05	05/15/35	250,000,000	13,375,000	18
						19
11/15/05	11/15/15	11/15/05	11/15/15		11,520,138	20
						21
06/08/06	06/01/26	06/08/06	06/01/26	250,000,000	15,000,000	22
						23
09/21/06	07/01/18	09/21/06	07/01/18	161,240,000	2,660,460	24
						25
09/20/07	09/15/37	09/20/07	09/15/37	250,000,000	15,312,500	26
						27
05/14/09	06/01/39	05/14/09	06/01/39	300,000,000	18,000,000	28
						29
05/13/10	05/15/40	05/13/10	05/15/40	250,000,000	13,375,000	30
						31
08/26/10	08/15/40	08/26/10	08/15/40	500,000,000	22,500,000	32
				4,043,298,000	188,053,798	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	/ /	End of 2015/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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
08/18/11	08/15/21	08/18/11	08/15/21	350,000,000	10,500,000	2
						3
11/17/11	11/15/41	11/17/11	11/15/41	250,000,000	9,875,000	4
						5
03/22/12	04/01/42	03/22/12	04/01/42	250,000,000	10,750,000	6
						7
09/09/13	09/01/23	09/09/13	09/01/23	450,000,000	16,200,000	8
						9
03/12/15	09/09/17	03/12/15	09/09/17	140,000,000	567,370	10
						11
03/12/15	02/01/22	03/12/15	02/01/22	232,143,000	3,703,598	12
						13
				3,989,648,000	183,493,384	14
						15
						16
						17
						18
						19
						20
						21
08/02/96	07/01/21	08/02/96	07/01/21		1,357,286	22
						23
11/21/96	12/01/21	11/21/96	12/01/21		2,172,615	24
						25
10/31/97	03/01/23	10/31/97	03/01/23		806,459	26
						27
05/19/14	05/20/15	05/19/14	05/20/15		156,768	28
						29
11/19/15	11/21/16	11/19/15	11/21/16	53,650,000	67,286	30
						31
				53,650,000	4,560,414	32
				4,043,298,000	188,053,798	33

Schedule Page: 256.1 Line No.: 14 Column: c

Expense	$49,370,196
Discount	13,435,000
Account 221	$62,805,196

Schedule Page: 256.1 Line No.: 32 Column: a

Item 2:

FERC authorization is not required on routine issues.

Item 11:

Long Term Commercial paper was issued in 2015

Item 15:

Account 221	$183,493,384
Account 224	4,560,414
Total Page 257.1 [Column (i)]	$188,053,798

Item 16:

D.12-03-005 - In March 2012, SDG&E received authority from the California Public Utilities Commission to issue $750,000,000 of new debt under Decision 12-03-005. At December 2015, the total remaining authority for new debt was $65,430,000.

D.15-08-011 - In August 2015, SDG&E received authority from the California Public Utilities Commission to issue $1,000,000,000 of new debt under Decision 15-08-011 and $300,000,000 in rollover debt. SDG&E has not issued any debt under this decision.

Schedule Page: 256.1 Line No.: 32 Column: c

Expense	$1,662,686
Discount	0
Account 224	$1,662,686

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)	584,687,607
2	Reconciling Items for the Year:	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	40,519,483
6	Regulatory Balancing Accounts	490,301,348
7	Tax on State Audit Payments	40,858,943
8	Other	9,983,496
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	577,836,850
11	Federal and State Taxes	283,692,721
12	Amortization and Interest Capitalized	43,616,675
13	Other	14,647,028
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	-50,855,480
16	Deferred Construction Revenue	-6,891,487
17	Keyman LIfe Insurance	-4,967,255
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-697,695,819
21	Percentage Repair Allowance	-128,009,271
22	Software Development Costs	-68,825,372
23	Current State Tax Deduction	-41,039,381
24	Removal Costs	-57,371,632
25	Book Gain/Loss on Sale of Non-Utility Property	-21,193,374
26	Other	-47,233,217
27	Federal Tax Net Income	962,061,888
28	Show Computation of Tax:	
29	Federal Tax @ 35%	336,721,661
30	Deferred Taxes	-88,652,006
31	Tax Credits and Other Adjustments (net)	-4,248,744
32	Fed Discrete Taxes	-2,482,486
33	Total Federal Income Tax Expense	241,338,425
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 8 Column: b

Fuel Tax Credit Addback	$ 9,000
GAA Retirements Election	9,974,496
Total	$ 9,983,496

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

Interest on Audit Payments	$ 7,693,630
SERP	856,384
Miscellaneous Expenses	6,097,014
Total	$ 14,647,028

Schedule Page: 261 Line No.: 20 Column: b

South Georgia Adjustment of $2,333,000 is included in book taxable income to reverse tax benefits flowed through in rates prior to full normalization of book/tax adjustments.

Schedule Page: 261 Line No.: 26 Column: b

Amortization on Loss on Reacquired Debt	$ (2,723,536)
Contingency Book Reserves	(3,159,701)
Qualified Decommissioning Contributions	(7,705,000)
Property Tax / Ad Valorem	(5,187,451)
Facts & Circumstances Repairs	(14,306,178)
Abandonment Loss	(13,301,537)
Miscellaneous Expenses	(849,814)
Total	$(47,233,217)

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	/ /	End of 2015/Q4

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)		1,471,451	107,243,208	115,210,235	-8,577,482
3	Sales and Use	20,456		189,645	191,849	
4						
5						
6	SUBTOTAL	20,456	1,471,451	107,432,853	115,402,084	-8,577,482
7						
8	STATE:					
9	Franchise (Note 3)	165,132,100		97,868,479	287,385,711	21,807,739
10	Unemployment (Note 4)	315,406		1,257,057	1,226,294	
11	Sales and Use (Note 2)	67,690		568,935	575,551	
12	Fuel Tax	11,551		7,131	10,188	
13						
14	SUBTOTAL	165,526,747		99,701,602	289,197,744	21,807,739
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)		140,209,659	11,320,542	-178,303,222	53,245,640
18	Retirement (Note 4)	777,378		26,833,488	26,746,909	
19	Unemployment (Note 4)	461,555		290,876	200,444	
20	Medicare (Note 4)	206,116		7,993,165	7,986,232	
21	Fuel Tax	-4,852		-255,174	-226,569	
22						
23						
24	SUBTOTAL	1,440,197	140,209,659	46,182,897	-143,596,206	53,245,640
25						
26	Citizens Payroll Tax					
27						
28	Other - Foreign Tax					
29						
30						
31						
32						
33	Note 1					
34						
35	Note 2					
36						
37	Note 3					
38						
39	Note 4					
40						
41	TOTAL	166,987,400	141,681,110	253,317,352	261,003,622	66,475,897

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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
	860,997	96,002,476			11,240,694	2
18,241					189,645	3
						4
						5
18,241	860,997	96,002,476			11,430,339	6
						7
						8
	2,577,393	101,466,804	2,307,888		-5,906,213	9
346,168		966,187			290,870	10
61,036					568,935	11
8,494					7,131	12
						13
415,698	2,577,393	102,432,991	2,307,888		-5,039,277	14
						15
						16
	3,831,535	7,277,252	8,329,806		-4,286,516	17
863,957		10,812,410			16,021,107	18
551,987		223,571			67,306	19
213,049		3,220,803			4,772,371	20
-33,457					-255,174	21
						22
						23
1,595,536	3,831,535	21,534,036	8,329,806		16,319,094	24
						25
		-38,381			38,381	26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
2,029,475	7,269,925	219,931,122	10,637,694		22,748,537	41

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

This adjustment is for a portion of property taxes paid on construction work in progress. The property tax charged during the year was reduced and capitalized to certain assets under construction.

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

Amount includes Ad Valorem taxes on SONGS in the amount of $1,961,181.

Property Tax expsnses of $630,018 associated with the Citizens portion of the Border-Eastline are deducted and moved to column (l).

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

Includes property tax expense of $630,018 associated with the Citizens portion of the Border-Eastline.

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

Taxes Paid/Received were adjusted for interest income received for the FTB settlement refund. Amounts were never accrued.

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

Description	Adjustment Amount	FERC 165/236	FERC 190	FERC 0
Balance Sheet Reclassification Between Federal and State	(176,448)	(176,448)		
Balance Sheet Reclassification Due to FIN 48 Liabilities	(515,720)		(515,720)	
Tax Adjustment Related to 1998-2005 Franchise Tax Board Settlement	22,499,907		22,499,907	
Total - California Corporation Franchise Tax Adjustment	21,807,739	(176,448)	21,984,187	-

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

Description	Adjustment Amount	FERC 165/236	FERC 190	FERC
Balance Sheet Reclassification Between Federal and State	(176,448)	176,448		
Balance Sheet Reclassification Due to FIN 48 Liabilities	6,300,805		(6,300,805)	
Tax Adjustment Related to 1998-2005 Franchise Tax Board Settlement	47,121,283		(47,121,283)	
Total - Federal Income Tax Adjustment	53,245,640	176,448	(53,422,088)	-

Schedule Page: 262 Line No.: 18 Column: i

Payroll taxes of $38,381 associated with the Citizens Border-Eastline are included in total payroll.

Schedule Page: 262 Line No.: 26 Column: i

Payroll taxes of $38,381 associated with the Citizens Boreder-Eastline are deducted and moved to column (l).

Schedule Page: 262 Line No.: 26 Column: l

The $38,381 reflects payroll taxes associated with the Border-Eastline allocated and charged to Citizens.

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

Note 1:

Ad Valorem taxes are allocated based on 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 and Franchise Tax and Federal Income Tax are charged to departments based on 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.

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	Various	18,071,296			411.4	2,355,653	
7							
8	TOTAL	18,071,296				2,355,653	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility Various	3,543,869			411.4	530,581	
11							
12							
13							
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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	/ /	End of 2015/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
15,715,643	25 to 30 years		6
			7
15,715,643			8
			9
3,013,288	25 to 30 years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			48

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

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

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	/ /	End of 2015/Q4

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 $100,000, 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	79,202,360	269/456/495	14,029,582	4,862,350	70,035,128
2	Amortized over various 31 yr lives					
3						
4	SONGS Mitigation	14,158,800	182.3	6,101,293	4,776,952	12,834,459
5						
6	OII Insurance Limited	3,857,000	924	152,500		3,704,500
7						
8	Sunrise Fire Mitigation Liability	112,826,124	242	3,301,736	4,223,006	113,747,394
9						
10	CA ISO Fund Due to Customers	12,495,975				12,495,975
11						
12	Citizens Lease	75,375,628	242	2,836,960		72,538,668
13						
14	GHG Allowance		158/253	111,069,042	144,806,013	33,736,971
15						
16	Miscellaneous	11,799,768	Various	47,809,904	50,079,722	14,069,586
17						
18						
19						
20						
21						
22						
23						
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25						
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41						
42						
43						
44						
45						
46						
47	TOTAL	309,715,655		185,301,017	208,748,043	333,162,681

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	/ /	End of 2015/Q4

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	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
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)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

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	/ /	End of 2015/Q4

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.
		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)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
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							12
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							21

NOTES (Continued)

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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	1,652,733,902	168,454,480	80,265,898
3	Gas	117,867,047	28,010,658	8,489,321
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,770,600,949	196,465,138	88,755,219
6				
7	Non Utility	204,874,497		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,975,475,446	196,465,138	88,755,219
10	Classification of TOTAL			
11	Federal Income Tax	1,828,918,373	177,679,382	76,559,121
12	State Income Tax	146,557,073	18,785,756	12,196,098
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	7,279,987	Various	184,252,073	1,917,894,570	2
				Various	-1,663,163	135,725,221	3
							4
			7,279,987		182,588,910	2,053,619,791	5
							6
10,854,662	69,115,038			Various	-168,603,689	-21,989,568	7
							8
10,854,662	69,115,038		7,279,987		13,985,221	2,031,630,223	9
							10
9,643,437	55,264,002		5,700,566		-55,156,625	1,823,560,878	11
1,211,225	13,851,036		1,579,421		69,141,846	208,069,345	12
							13

NOTES (Continued)

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

Non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $612,790,263.

Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $14,613.

Allocated General and Common accumulated deferred federal income taxes included in transmission related accumulated deferred federal income taxes at the beginning of the year was $19,280,027.

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

Non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $878,415,167.

Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $23,707.

Allocated General and Common accumulated deferred federal income taxes included in transmission related accumulated deferred income taxes at the end of the year was $17,331,399.

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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		587,201,507	45,157,993	221,106,096
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	587,201,507	45,157,993	221,106,096
10	Gas			
11		51,770,995	4,251,747	28,591,754
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	51,770,995	4,251,747	28,591,754
18	Non Utility	103,956,010		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	742,928,512	49,409,740	249,697,850
20	Classification of TOTAL			
21	Federal Income Tax	547,310,717	42,946,413	199,781,254
22	State Income Tax	195,617,795	6,463,327	49,916,596
23	Local Income Tax			

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	/ /	End of 2015/Q4

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
		182.3	2,544,727	Various	194,083,467	602,792,144	3
							4
							5
							6
							7
							8
			2,544,727		194,083,467	602,792,144	9
							10
		190	781,909	Various	34,120,740	60,769,819	11
							12
							13
							14
							15
							16
			781,909		34,120,740	60,769,819	17
1,271,795	1,186,565			Various	-78,214,653	25,826,587	18
1,271,795	1,186,565		3,326,636		149,989,554	689,388,550	19
							20
1,031,034	964,295		8,255,802		157,862,302	540,149,115	21
240,761	222,270		-4,929,166		-7,872,748	149,239,435	22
							23

NOTES (Continued)

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

Transmission allocation of accumulated deferred income taxes related to electric miscellaneous intangible plant at the beginning of the year was $4,764,722.

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

Transmission allocation of accumulated deferred income taxes related to electric miscellaneous intangible plant at the end of the year was $5,628,143.

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	/ /	End of 2015/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 $100,000 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	43,236,159	190/182.3/282/283	10,675,638		32,560,521
3						
4						
5	Asset Retirement Obligations	487,576,672	230	272,123,121	285,455,515	500,909,066
6						
7						
8	Balancing Account Overcollections	768,665,296	456	12,275,154		756,390,142
9						
10						
11	Electric / Gas Derivatives	106,617,401	175.1	840,498,768	810,210,596	76,329,229
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	TOTAL	1,406,095,528		1,135,572,681	1,095,666,111	1,366,188,958

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

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	1,486,308,656	1,369,693,579
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,507,963,745	1,418,771,861
5	Large (or Ind.) (See Instr. 4)	380,735,134	342,271,622
6	(444) Public Street and Highway Lighting	15,263,946	14,645,239
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,390,271,481	3,145,382,301
11	(447) Sales for Resale	579,635,264	707,646,929
12	TOTAL Sales of Electricity	3,969,906,745	3,853,029,230
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,969,906,745	3,853,029,230
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	93,141,013	88,286,798
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,311,346	7,493,956
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-54,553,380	482,529,097
22	(456.1) Revenues from Transmission of Electricity of Others	291,649,708	162,350,733
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	334,548,687	740,660,584
27	TOTAL Electric Operating Revenues	4,304,455,432	4,593,689,814

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	/ /	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. 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.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. 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
7,143,500	7,330,498	1,264,642	1,256,446	2
				3
6,877,018	6,967,806	149,517	148,648	4
2,163,463	2,064,553	464	454	5
83,032	87,332	2,037	2,056	6
				7
				8
				9
16,267,013	16,450,189	1,416,660	1,407,604	10
16,865,020	14,502,768	1	1	11
33,132,033	30,952,957	1,416,661	1,407,605	12
				13
33,132,033	30,952,957	1,416,661	1,407,605	14

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

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

Schedule Page: 300 Line No.: 17 Column: b

Description

San Diego Franchise Fee Surcharge	$88,007,838
Service Establishment	2,427,250
Late Payment Charge	721,575
Other*	1,984,350
	$93,141,013

* Individual balances are less than $250,000

Schedule Page: 300 Line No.: 19 Column: c

Includes Transmission Revenue Credits of $709,930

Schedule Page: 300 Line No.: 21 Column: b

Description

Direct Access	$229,490,396
Balancing Accounts	(406,521,543)
Cap and Trade Revenues	79,929,224
Litigation	11,536,390
CIAC Income Tax	6,033,360
Shared Assets	6,795,152
PUC Reimbursement Fee	4,565,807
Government Turnkey	595,187
Unbilled Revenue	1,246,000
Joint Pole Activity	1,429,367
Generation Trans. Interconnection Rev.	4,002,531
Electric Revenue Cycle Credits	6,104,749
Other*	(240,000)
	($54,553,380)

* Individual balances are less than $250,000

Schedule Page: 300 Line No.: 21 Column: c

Includes Transmission Revenue Credits of $5,861,554

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	/ /	End of 2015/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					
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19					
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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				

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	/ /	End of 2015/Q4

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	5,598,880	1,287,376,561	992,640	5,640	0.2299
2	DRTOU	28,694	5,459,212	3,639	7,885	0.1903
3	EVTOU	71,826	15,175,356	5,918	12,137	0.2113
4	EPEV	7	1,519			0.2170
5	DRLI	1,218,919	145,635,783	256,101	4,760	0.1195
6	DM	46,620	9,456,541	3,663	12,727	0.2028
7	DS	17,747	2,248,323	235	75,519	0.1267
8	DT	158,919	20,254,504	443	358,734	0.1275
9	OL-1	1,656	564,303	1,959	845	0.3408
10	DWL	231	136,554	44	5,250	0.5911
11	Total Residential Sales (440)	7,143,499	1,486,308,656	1,264,642	5,649	0.2081
12						
13	A	1,820,869	440,093,861	117,233	15,532	0.2417
14	ATOU	27,547	7,311,573	618	44,574	0.2654
15	ASTOD	46,874	10,881,940	4,542	10,320	0.2322
16	AD	34,111	8,695,845	189	180,481	0.2549
17	UM	5,471	1,313,016	67	81,657	0.2400
18	PA	81,875	14,410,432	3,392	24,138	0.1760
19	PAT1	220,214	34,753,207	487	452,185	0.1578
20	AL-TOU	4,510,673	957,287,448	20,608	218,880	0.2122
21	SPSS		-34,964	5		
22	DG		98,939			
23	AY-TOU	119,200	30,551,280	518	230,116	0.2563
24	OL-1	4,617	1,264,339	1,771	2,607	0.2738
25	OLTOU	5,566	1,336,829	87	63,977	0.2402
26	Total Commerical (444)	6,877,017	1,507,963,745	149,517	45,995	0.2193
27						
28	AL-TOU	2,120,534	370,169,816	451	4,701,849	0.1746
29	SPSS					
30	DG		1,001,005			
31	A6-TOU	42,928	9,564,313	13	3,302,154	0.2228
32	Total Industrial (442)	2,163,462	380,735,134	464	4,662,634	0.1760
33						
34	LS1	15,584	5,794,967	767	20,318	0.3719
35	LS2	65,524	9,198,814	1,115	58,766	0.1404
36	LS3	1,924	270,165	155	12,413	0.1404
37	Total Public Street and Hwy (444)	83,032	15,263,946	2,037	40,762	0.1838
38						
39						
40						
41	TOTAL Billed	16,267,013	3,390,271,481	1,416,660	11,483	0.2084
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	16,267,013	3,390,271,481	1,416,660	11,483	0.2084

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	/ /	End of 2015/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 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	Arizona Public Service Company	SF	FERC Vol. 10			
2	Avista Corporation	SF	FERC Vol. 10			
3	Bonneville Power Administration	SF	FERC Vol. 10			
4	California ISO					
5	Cargill Power Markets	SF	FERC Vol. 10			
6	City of Escondido (Rincon Hydro Plant)	SF	FERC Vol. 10			
7	Calpine Energy Services LP	SF	FERC Vol. 10			
8	City of Anaheim	SF	FERC Vol. 10			
9	City of Burbank	SF	FERC Vol. 10			
10	City of Corona	SF	FERC Vol. 10			
11	City of Glendale Water and Power	SF	FERC Vol. 10			
12	City of Riverside	SF	FERC Vol. 10			
13	Citigroup Energy LLC	SF	FERC Vol. 10			
14						
	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	/ /	End of 2015/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:

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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.

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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	Commerce Energy LLC	SF	FERC Vol. 10			
2	Constellation Energy Commodities Group	SF	FERC Vol. 10			
3	EDF Trading North America LLC	SF	FERC Vol. 10			
4	Energy America LLC	SF	FERC Vol. 10			
5	Exelon Generation Company LLC	SF	FERC Vol. 10			
6	Imperial Irrigation District	AD	FERC Vol. 10			
7	J. Aron & Company LLC	SF	FERC Vol. 10			
8	J.P. Morgan Venture Energy Corporation	SF	FERC Vol. 10			
9	Los Angeles Dept. of Water & Power	SF	FERC Vol. 10			
10	Macquarie Energy LLC	SF	FERC Vol. 10			
11	Modesto Irrigation District	SF	FERC Vol. 10			
12	Morgan Stanley Capital Group	SF	FERC Vol. 10			
13	Nevada Power Company	SF	FERC Vol. 10			
14	Noble Americas Energy Solutions LLC	SF	FERC Vol. 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).
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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	Northern California Power Agency	SF	FERC Vol. 10			
2	NRG Power Marketing LLC	SF	FERC Vol. 10			
3	PacifiCorp	SF	FERC Vol. 10			
4	Pilot Power Group Inc	SF	FERC Vol. 10			
5	Portland General Electric	SF	FERC Vol. 10			
6	Powerex Corporation	SF	FERC Vol. 10			
7	Public Service Company of New Mexico	SF	FERC Vol. 10			
8	Puget Sound Energy	SF	FERC Vol. 10			
9	Sacramento Municipal Utility District	SF	FERC Vol. 10			
10	Salt River Project	SF	FERC Vol. 10			
11	San Diego County Water Authority	SF	FERC Vol. 10			
12	Seattle City Light	SF	FERC Vol. 10			
13	Shell Energy North America (US) LP	SF	FERC Vol. 10			
14	Silicon Valley Power	SF	FERC Vol. 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	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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	Snohomish County PUD No. 1	SF	FERC Vol. 10			
2	Southern California Edison	SF	FERC Vol. 10			
3	Tacoma Power	SF	FERC Vol. 10			
4	TGP Energy Management	SF	FERC Vol. 10			
5	TransAlta Energy Marketing US	SF	FERC Vol. 10			
6	Turlock Irrigation District	SF	FERC Vol. 10			
7	Western Area Power Administration	SF	FERC Vol. 10			
8						
9	Accrual/Accrual Reversal					
10						
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.
2,431		91,903		91,903	1
					2
					3
15,657,007		526,778,962		526,778,962	4
					5
31		4,862		4,862	6
					7
222		10,236		10,236	8
4,183		203,959		203,959	9
					10
2,000		60,100		60,100	11
					12
					13
					14
0	0	0	0	0	
16,865,020	54,600	564,530,296	15,050,368	579,635,264	
16,865,020	**54,600**	**564,530,296**	**15,050,368**	**579,635,264**	

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	/ /	End of 2015/Q4

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
					2
1,600		48,400		48,400	3
	54,600			54,600	4
300,000		9,458,526	6,750,000	16,208,526	5
					6
					7
					8
2,800		76,880		76,880	9
					10
					11
467,890		14,833,558		14,833,558	12
					13
201,480		6,344,167	4,168,920	10,513,087	14
0	0	0	0	0	
16,865,020	54,600	564,530,296	15,050,368	579,635,264	
16,865,020	**54,600**	**564,530,296**	**15,050,368**	**579,635,264**	

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) / /	End of 2015/Q4

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
					2
					3
115,056		3,546,924	2,736,448	6,283,372	4
					5
400		9,000		9,000	6
					7
					8
					9
					10
					11
					12
800		51,600		51,600	13
					14
0	0	0	0	0	
16,865,020	54,600	564,530,296	15,050,368	579,635,264	
16,865,020	**54,600**	**564,530,296**	**15,050,368**	**579,635,264**	

SALES FOR RESALE (Account 447) (Continued)

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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
1,000		28,200		28,200	2
					3
105,720		2,877,419	1,395,000	4,272,419	4
2,400		105,600		105,600	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
16,865,020	54,600	564,530,296	15,050,368	579,635,264	
16,865,020	**54,600**	**564,530,296**	**15,050,368**	**579,635,264**	

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	/ /	End of 2015/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	2,010,154	1,717,263
5	(501) Fuel	126,727,159	152,206,869
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	256,102	225,533
10	(506) Miscellaneous Steam Power Expenses	7,775,598	6,424,011
11	(507) Rents	11,635	274,028
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	136,780,648	160,847,704
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	12,217	11,021
16	(511) Maintenance of Structures	103,928	-11,858
17	(512) Maintenance of Boiler Plant	3,118,185	1,856,305
18	(513) Maintenance of Electric Plant	583,166	5,883,464
19	(514) Maintenance of Miscellaneous Steam Plant	8,247,335	11,692,693
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,064,831	19,431,625
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	148,845,479	180,279,329
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	-497,275	28,044,302
25	(518) Fuel		
26	(519) Coolants and Water	-7,878	-114,689
27	(520) Steam Expenses	78,032	-271,238
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	2,154,769	12,196,096
32	(525) Rents	-9,528	549,055
33	TOTAL Operation (Enter Total of lines 24 thru 32)	1,718,120	40,403,526
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-7,960,088	4,204,810
36	(529) Maintenance of Structures	1,730	19,074
37	(530) Maintenance of Reactor Plant Equipment	5,294	-368,147
38	(531) Maintenance of Electric Plant	92	-296,207
39	(532) Maintenance of Miscellaneous Nuclear Plant	-240,964	4,385,963
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	-8,193,936	7,945,493
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	-6,475,816	48,349,019
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	1,363,263	838,601
63	(547) Fuel	2,864,536	4,584,263
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses	9,144,492	6,040,607
66	(550) Rents	690	
67	TOTAL Operation (Enter Total of lines 62 thru 66)	13,372,981	11,463,471
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	182	
70	(552) Maintenance of Structures	-19,038	-1,475
71	(553) Maintenance of Generating and Electric Plant	14,225,946	8,495,372
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	5,871,410	7,126,977
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	20,078,500	15,620,874
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	33,451,481	27,084,345
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,671,028,598	1,930,778,476
77	(556) System Control and Load Dispatching	3,324,194	3,016,467
78	(557) Other Expenses	7,426,768	6,627,998
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,681,779,560	1,940,422,941
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,857,600,704	2,196,135,634
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,142,785	8,273,221
84			
85	(561.1) Load Dispatch-Reliability	599,703	516,638
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,475,760	3,852,433
87	(561.3) Load Dispatch-Transmission Service and Scheduling	227,063	
88	(561.4) Scheduling, System Control and Dispatch Services	6,718,848	6,438,959
89	(561.5) Reliability, Planning and Standards Development	422,813	
90	(561.6) Transmission Service Studies	6,044	
91	(561.7) Generation Interconnection Studies	4,276	
92	(561.8) Reliability, Planning and Standards Development Services	3,613,237	2,764,211
93	(562) Station Expenses	4,305,577	2,212,912
94	(563) Overhead Lines Expenses	4,849,653	4,983,356
95	(564) Underground Lines Expenses	424	
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	23,510,103	19,174,670
98	(567) Rents	1,616,947	1,387,204
99	TOTAL Operation (Enter Total of lines 83 thru 98)	54,493,233	49,603,604
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	974,742	929,085
102	(569) Maintenance of Structures	543	223
103	(569.1) Maintenance of Computer Hardware	1,501,017	1,517,381
104	(569.2) Maintenance of Computer Software	2,865,486	1,471,740
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	200,638	243,392
107	(570) Maintenance of Station Equipment	6,431,297	5,834,088
108	(571) Maintenance of Overhead Lines	18,438,916	19,856,866
109	(572) Maintenance of Underground Lines	416,793	1,557,857
110	(573) Maintenance of Miscellaneous Transmission Plant	18,432	79,281
111	TOTAL Maintenance (Total of lines 101 thru 110)	30,847,864	31,489,913
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	85,341,097	81,093,517

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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	3,878,238	3,611,273
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,878,238	3,611,273
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)	3,878,238	3,611,273
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	20,261,619	16,468,011
135	(581) Load Dispatching	3,676,353	2,862,650
136	(582) Station Expenses	4,910,017	4,454,770
137	(583) Overhead Line Expenses	2,427,310	2,434,460
138	(584) Underground Line Expenses	2,533,843	2,425,854
139	(585) Street Lighting and Signal System Expenses	621,671	574,960
140	(586) Meter Expenses	10,722,449	10,021,917
141	(587) Customer Installations Expenses	5,793,072	5,555,830
142	(588) Miscellaneous Expenses	32,837,817	11,348,714
143	(589) Rents	476,435	526,486
144	TOTAL Operation (Enter Total of lines 134 thru 143)	84,260,586	56,673,652
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,479,120	1,207,014
147	(591) Maintenance of Structures	187,155	63,064
148	(592) Maintenance of Station Equipment	3,345,319	4,077,715
149	(593) Maintenance of Overhead Lines	41,183,868	40,806,422
150	(594) Maintenance of Underground Lines	9,104,513	7,870,466
151	(595) Maintenance of Line Transformers	15,925	143,915
152	(596) Maintenance of Street Lighting and Signal Systems	86,230	93,248
153	(597) Maintenance of Meters	1,512,087	1,077,930
154	(598) Maintenance of Miscellaneous Distribution Plant	267,268	205,131
155	TOTAL Maintenance (Total of lines 146 thru 154)	57,181,485	55,544,905
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	141,442,071	112,218,557
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		310
160	(902) Meter Reading Expenses	2,440,923	3,256,074
161	(903) Customer Records and Collection Expenses	37,914,774	36,095,083
162	(904) Uncollectible Accounts	4,860,860	4,223,339
163	(905) Miscellaneous Customer Accounts Expenses	236,372	322,200
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	45,452,929	43,897,006

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	26,307	23,675
168	(908) Customer Assistance Expenses	170,684,028	155,905,193
169	(909) Informational and Instructional Expenses	146,527	217,621
170	(910) Miscellaneous Customer Service and Informational Expenses	2,525,878	1,520,064
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	173,382,740	157,666,553
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	29,373,126	41,445,272
182	(921) Office Supplies and Expenses	-15,156,779	-59,221,092
183	(Less) (922) Administrative Expenses Transferred-Credit	9,451,453	7,789,598
184	(923) Outside Services Employed	142,156,284	155,503,644
185	(924) Property Insurance	4,752,704	5,605,942
186	(925) Injuries and Damages	101,140,890	233,101,860
187	(926) Employee Pensions and Benefits	31,678,317	55,582,677
188	(927) Franchise Requirements	125,260,417	116,190,759
189	(928) Regulatory Commission Expenses	15,618,351	16,811,832
190	(929) (Less) Duplicate Charges-Cr.	2,166,846	2,050,000
191	(930.1) General Advertising Expenses	136,091	396,852
192	(930.2) Miscellaneous General Expenses	11,973,407	16,292,848
193	(931) Rents	11,131,728	10,061,145
194	TOTAL Operation (Enter Total of lines 181 thru 193)	446,446,237	581,932,141
195	Maintenance		
196	(935) Maintenance of General Plant	8,996,726	8,526,308
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	455,442,963	590,458,449
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,762,540,742	3,185,080,989

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	/ /	End of 2015/Q4

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.

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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	Arlington Valley Solar I LLC	LU	FERC Vol. 10			
2	Applied Energy Inc	LU	FERC Vol. 10			
3	Blue Lake Power LLC	LU	FERC Vol. 10			
4	California ISO					
5	Calpeak Power LLC	OS				
6	Calpine Energy Services, L.P.	IF	FERC Vol. 10			
7	Campo Verde Solar LLC	LU	FERC Vol. 10			
8	Cascade Solar LLC	LU	FERC Vol. 10			
9	Catalina Solar LLC	LU	FERC Vol. 10			
10	Centinela Solar Energy LLC	LU	FERC Vol. 10			
11	Centinela Solar Energy 2 LLC	LU	FERC Vol. 10			
12	City of Escondido	LU	FERC Vol. 10			
13	City of Oceanside	LU	FERC Vol. 10			
14	City of Riverside	SF	FERC Vol. 10			
	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	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	LU	FERC Vol. 10			
2	Coram Energy LLC	LU	FERC Vol. 10			
3	Covanta Delano Inc	LU	FERC Vol. 10			
4	CP Kelco US Inc	LU	FERC Vol. 10			
5	CSolar IV South	LU	FERC Vol. 10			
6	CSolar IV West	LU	FERC Vol. 10			
7	Desert Green Solar Farm LLC	LU	FERC Vol. 10			
8	Dynegy Power Mktg Inc	AD	FERC Vol. 10			
9	El Cajon Energy Center (Tolling)	LU	FERC Vol. 10			
10	Energia Sierra Juarez	LU	FERC Vol. 10			
11	EnerNoc Inc	LU	FERC Vol. 10			
12	Escondido Energy Center LLC	LU	FERC Vol. 10			
13	FPL Energy Green Power Wind, LLC	LU	FERC Vol. 10			
14	Gas Recovery Systems	LU	FERC Vol. 10			
	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.
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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)	Average Monthly CP Demand (f)
1	Goal Line LP	LU	FERC Vol. 10			
2	Grossmont Hospital Corporation	LU	FERC Vol. 10			
3	Iberdrola Renewables LLC	LU	FERC Vol. 10			
4	Imperial Valley Solar I LLC	LU	FERC Vol. 10			
5	LanEast Solar Farm, LLC	LU	FERC Vol. 10			
6	LanWest Solar Farm, LLC	LU	FERC Vol. 10			
7	Kumeyaay Wind LLC	LU	FERC Vol. 10			
8	Maricopa West Solar PV LLC	LU	FERC Vol. 10			
9	Mesa Wind Power Corporation	LU	FERC Vol. 10			
10	MM Prima Deshecha Energy LLC	LU	FERC Vol. 10			
11	MM San Diego LLC	LU	FERC Vol. 10			
12	Morgan Stanley Capital Group	LU	FERC Vol. 10			
13	Naturener Glacier Wind Energy 1 LLC	EX				
14	Naturener Glacier Wind Energy 2 LLC	EX				
	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	/ /	End of 2015/Q4

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.
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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.

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1	Naturener Rim Rock Wind Energy LLC	EX				
2	NLP Valley Center		FERC Vol. 10			
3	NRG Solar Borrego LLC	LU	FERC Vol. 10			
4	NRG Power Marketing Inc (Tolling)	AD	FERC Vol. 10			
5	Oak Creek Wind Power LLC	LU	FERC Vol. 10			
6	Oasis Power Partners LLC	LU	FERC Vol. 10			
7	Ocotillo Express LLC	LU	FERC Vol. 10			
8	Olivenhain Muni Water District	LU	FERC Vol. 10			
9	Orange Grove Energy Center (Tolling)	LU	FERC Vol. 10			
10	Otay Landfill Gas LLC	LU	FERC Vol. 10			
11	Otay Mesa Energy Center (Tolling)	LU	FERC Vol. 10			
12	Pacific Wind Lessee LLC	LU	FERC Vol. 10			
13	Portland General Electric	LU	FERC Vol. 10			
14	San Diego County Water Authority (Hod)	LU	FERC Vol. 10			
	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	/ /	End of 2015/Q4

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.
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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	San Diego County Water Authority (PQ)	LU	FERC Vol. 10			
2	San Gorgonio Westwinds II, LLC	LU	FERC Vol. 10			
3	San Marcos Energy LLC	LU	FERC Vol. 10			
4	Santa Fe Irrigation District	SF	FERC Vol. 10			
5	SG2 imperial Valley LLC	LU	FERC Vol. 10			
6	Sol Orchard 20 LLC	LU	FERC Vol. 10			
7	Sol Orchard 21 LLC	LU	FERC Vol. 10			
8	Sol Orchard 22 LLC	LU	FERC Vol. 10			
9	Sol Orchard 23 LLC	LU	FERC Vol. 10			
10	Southern California Edison Company	IF	FERC Vol. 10			
11	Sycamore Energy 1 LLC	LU	FERC Vol. 10			
12	Sycamore Energy 2 LLC	LU	FERC Vol. 10			
13	Tallbear Seville LLC	LU	FERC Vol. 10			
14	Tierra Del Sol Solar Farm, LLC	LU	FERC Vol. 10			
	Total					

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

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.
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1	Yuma Co-generator Association	LU	FERC Vol. 10			
2	Anahau Energy LLC	SF	FERC Vol. 10			
3	Arizona Public Service Company	SF	FERC Vol. 10			
4	Atlantic Coast Energy Corp	SF	FERC Vol. 10			
5	Avista Corporation	SF	FERC Vol. 10			
6	Bonneville Power Administration	SF	FERC Vol. 10			
7	BP Energy Company	SF	FERC Vol. 10			
8	Calpine Energy Services, L.P.	SF	FERC Vol. 10			
9	Cargill Power Markets LLC	SF	FERC Vol. 10			
10	Chula Vista Energy Center LLC	SF	FERC Vol. 10			
11	Citigroup Energy Inc	SF	FERC Vol. 10			
12	City of Anaheim	SF	FERC Vol. 10			
13	City of Burbank	SF	FERC Vol. 10			
14	Comision Federal De Electricdad	SF	FERC Vol. 10			
	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	/ /	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Constellation Energy Commodities Group	SF	FERC Vol. 10			
2	DES Wholesale LLC	SF	FERC Vol. 10			
3	EDF Trading North America LLC	SF	FERC Vol. 10			
4	GenOn Energy Management LLC	SF	FERC Vol. 10			
5	Iberdrola Renewables	SF	FERC Vol. 10			
6	ICC Energy Corp	SF	FERC Vol. 10			
7	JP Morgan Ventures Energy	SF	FERC Vol. 10			
8	Macquarie Energy LLC	SF	FERC Vol. 10			
9	Morgan Stanley Capital Group Inc	SF	FERC Vol. 10			
10	Noble Americas Gas & Power Corp	SF	FERC Vol. 10			
11	NRG Power Marketing LLC	SF	FERC Vol. 10			
12	NV Energy (Nevada Power Company)	SF	FERC Vol. 10			
13	PacifiCorp	SF	FERC Vol. 10			
14	Pacific Gas & Electric	SF	FERC Vol. 10			
	Total					

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Pinnacle West Capital Corporation	SF	FERC Vol. 10			
2	Portland General Electric Company	SF	FERC Vol. 10			
3	Powerex Corporation	SF	FERC Vol. 10			
4	Public Service Company of New Mexico	SF	FERC Vol. 10			
5	Puget Sound Energy	SF	FERC Vol. 10			
6	Sacramento Municipal Utility District	SF	FERC Vol. 10			
7	Salt River Project	SF	FERC Vol. 10			
8	Seattle City Light	SF	FERC Vol. 10			
9	Shell Energy North America (US) LP	SF	FERC Vol. 10			
10	Snohomish County Public Utility	SF	FERC Vol. 10			
11	Southern California Edison Company	SF	FERC Vol. 10			
12	Southern Energy Solution Group LLC	SF	FERC Vol. 10			
13	Tacoma Power	SF	FERC Vol. 10			
14	The Energy Authority	SF	FERC Vol. 10			
	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	/ /	End of 2015/Q4

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	The Finerty Group Inc	SF	FERC Vol. 10			
2	TransAlta Energy Marketing (US) Inc	SF	FERC Vol. 10			
3	Turlock Irrigation District	SF	FERC Vol. 10			
4	Western Area Power Administration	SF	FERC Vol. 10			
5	W Power LLC	SF	FERC Vol. 10			
6	Broker Fees	OS				
7	Hedging Activity	OS				
8	Re-MAT Program Fee	OS				
9	ONDA Energy	OS				
10	Trimark Associates Inc	OS				
11	Vazquez & Company	OS				
12	Victor Mesa Linda B	OS				
13	GHG Allowances	OS				
14	Cabazon Wind Partners LLC	OS				
	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		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)	
374,407			-14,535	43,546,336	856,325	44,388,126	1
820,031			18,825,736	27,254,642		46,080,378	2
28,388				1,731,588	-19,957,220	-18,225,632	3
17,953,324				626,231,540	-23,434,615	602,796,925	4
			5,821,897			5,821,897	5
				-234		-234	6
368,935			40,765	42,600,310	-36,899	42,604,176	7
55,967			-5	4,112,163	-5,493	4,106,665	8
279,893			23,321	35,598,697	-27,785	35,594,233	9
378,875				52,398,756	-37,695	52,361,061	10
132,890			-91	17,854,933	-13,198	17,841,644	11
15,618			140,190	-54,842		85,348	12
495			3,439	15,871		19,310	13
10				290		290	14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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)	
15,974			-1,211	1,207,602		1,206,391	1
23,389				2,278,607	-2,343	2,276,264	2
358,733			6,807,018	18,887,290		25,694,308	3
32,028			163,203	1,030,780		1,193,983	4
320,347			38,265	45,019,024	-32,035	45,025,254	5
88,955				10,055,491		10,055,491	6
15,835				2,157,456	-1,584	2,155,872	7
							8
15,797			7,013,008	1,043,724		8,056,732	9
269,477			2,749	29,250,327	-23,389	29,229,687	10
			1,772,173			1,772,173	11
47,380			7,147,160	2,449,184		9,596,344	12
20,649				1,382,000		1,382,000	13
				-55,990		-55,990	14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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.
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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.
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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)	
22,768			8,913,037	2,969,100	3,401	11,885,538	1
4			6	66		72	2
295,640				20,714,536	150,640	20,865,176	3
568,608			61,943	64,109,184	2,766,158	66,937,285	4
				-484,420		-484,420	5
				-121,270		-121,270	6
124,097				6,467,840		6,467,840	7
2,986				127,396	-1,021,299	-893,903	8
							9
39,573				2,348,892		2,348,892	10
30,134			889	2,619,455		2,620,344	11
150,480				7,270,951		7,270,951	12
	268,048	268,048		5,723,430		5,723,430	13
	264,714	264,714		7,623,765		7,623,765	14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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)	
	609,672	609,672		26,817,712		26,817,712	1
							2
71,714			8,592	10,400,031	-7,147	10,401,476	3
							4
4,546			270	305,806	-455	305,621	5
156,497				6,825,748		6,825,748	6
537,442			19,231	56,430,831	-53,744	56,396,318	7
938				112,317		112,317	8
46,471			16,703,893	1,870,538		18,574,431	9
50,559				4,859,821		4,859,821	10
3,599,640			66,038,394	103,703,596		169,741,990	11
267,030			10,698	30,833,944	-26,703	30,817,939	12
800				18,600		18,600	13
-12,214			2,456,964	138,765		2,595,729	14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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	/ /	End of 2015/Q4

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.
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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)	
2,294				117,363		117,363	1
33,014			240	2,345,372	-3,355	2,342,257	2
12,440			36	1,463,752		1,463,788	3
194			6,882	6,500		13,382	4
420,005				27,428,679	24,174	27,452,853	5
4,743			705	605,254	-496	605,463	6
11,765			1,352	1,498,123	-1,176	1,498,299	7
6,153			620	787,126	-593	787,153	8
12,250			1,462	1,570,294	-1,225	1,570,531	9
							10
4,917			-919	573,256		572,337	11
15,485			-120	1,381,771		1,381,651	12
4,745				246,471	-474	245,997	13
				-1,142,970		-1,142,970	14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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.
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MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
27,099			6,852,467	922,050		7,774,517	1
3,840			198,546	110,592		309,138	2
							3
							4
							5
480				14,400		14,400	6
150,144				15,014,400		15,014,400	7
800				18,400		18,400	8
							9
							10
							11
155				3,160		3,160	12
							13
							14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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)	
							1
							2
			558,495			558,495	3
							4
-6,129				-383,103		-383,103	5
							6
							7
190,800				7,864,098		7,864,098	8
695,767				32,408,813	-103	32,408,710	9
							10
225			54,419,448			54,419,448	11
							12
							13
			214,500			214,500	14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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)	
							1
							2
400			539,950	9,000		548,950	3
							4
							5
							6
							7
							8
263,680			-95,900	8,757,687		8,661,787	9
							10
							11
							12
							13
							14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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)	
							1
							2
							3
							4
							5
					248,919	248,919	6
					41,224,181	41,224,181	7
					-33,588	-33,588	8
							9
							10
							11
							12
					36,479,982	36,479,982	13
							14
29,430,376	1,142,434	1,142,434	204,694,763	1,429,302,667	37,031,166	1,671,028,596	

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	/ /	End of 2015/Q4

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 Classifi-cation (d)
1	CAISO	N/A	N/A	OS
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				
	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	/ /	End of 2015/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
						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**	

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	/ /	End of 2015/Q4

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.
	291,649,708		291,649,708	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
0	**291,649,708**	**0**	**291,649,708**	

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	/ /	End of 2015/Q4

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	/ /	End of 2015/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 Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	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	/ /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	146,009
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	11,142,063
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Abandoned Project	963,239
7	Cost of Financing	384,074
8	Other	82,816
9	FERC Audit Adjustments	-744,794
10		
11		
12		
13		
14		
15		
16		
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32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	11,973,407

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			22,028,386		22,028,386
2	Steam Production Plant	18,904,420				18,904,420
3	Nuclear Production Plant	8,070,000				8,070,000
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	20,512,811			2,148	20,514,959
7	Transmission Plant	115,827,049			1,928,173	117,755,222
8	Distribution Plant	204,722,248			1,867,456	206,589,704
9	Regional Transmission and Market Operation					
10	General Plant	12,105,160				12,105,160
11	Common Plant-Electric	25,309,844		30,186,281		55,496,125
12	TOTAL	405,451,532		52,214,667	3,797,777	461,463,976

B. Basis for Amortization Charges

Account 404
The amortization of Intangible Plant (software) is based on the anticipated useful life of the software project.

Account 405
The amortization of Land Rights is based on the anticipated useful lives of the rights-of-way.

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	/ /	End of 2015/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-Palomar	57,997					
14	311-Desert Star	28,843					
15	312-Palomar	106,700					
16	312-Desert Star	49,165					
17	314-Palomar	109,295					
18	314-Desert Star	14,405					
19	315-Palomar	37,254					
20	315-Desert Star	45,490					
21	316-Palomar	38,034					
22	316-Desert Star	4,126					
23	SUBTOTAL	491,309					
24							
25	OTHER PRODUCTION						
26	341-PA/MM/CPEP	20,952					
27	341-Desert Star	1,751					
28	342-PA/MM/CPEP	19,754					
29	342-Desert Star	594					
30	343-PA/MM/CPEP	63,348					
31	343-Desert Star	22,336					
32	344-PA/MM/CPEP	192,891					
33	344-Desert Star	108,119					
34	344-Solar	40,159					
35	344-Wind	257					
36	345-PA/MM/CPEP	20,996					
37	345-Desert Star	9,194					
38	345-Solar	2,316					
39	346-PA/MM/CPEP	3,747					
40	346-Desert Star	22,352					
41	SUBTOTAL	528,766					
42							
43	TRANSMISSION-SWPL						
44	352	10,246					
45	353	209,025					
46	354	61,988					
47	355	10,488					
48	356	46,320					
49	359	5,324					
50	SUBTOTAL	343,391					

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	/ /	End of 2015/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							
13	TRANSMISSION-SUNRIS						
14	352	120,996					
15	353	158,422					
16	354	765,281					
17	355	3,490					
18	356	173,364					
19	357	80,502					
20	358	126,452					
21	359	218,125					
22	SUBTOTAL	1,646,632					
23							
24	TRANSMISSION-OTHER						
25	352	263,721					
26	353	833,259					
27	353.4	1,420					
28	354	66,293					
29	355	387,133					
30	356	311,954					
31	357	252,841					
32	358	224,479					
33	359	83,482					
34	SUBTOTAL	2,424,582					
35							
36	DISTRIBUTION						
37	361	4,033					
38	362	470,938					
39	363	19,492					
40	364	613,621					
41	365	502,379					
42	366	1,082,300					
43	367	1,398,858					
44	368.1	553,328					
45	368.2	23,966					
46	369.1	132,383					
47	369.2	328,399					
48	370.1-Meters	2,906					
49	370.11-Smart Meters	188,912					
50	370.2-Meter Installs	5,203					

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	370.21-Smart Meter Ins	50,498					
13	371	7,933					
14	373.2	26,927					
15	SUBTOTAL	5,412,076					
16							
17	GENERAL						
18	390	32,273					
19	392.2	58					
20	393	15					
21	394.1	23,126					
22	394.2	341					
23	395	2,402					
24	397.1-Other	220,608					
25	397.2-SWPL	6,808					
26	397.6-Sunrise	14,031					
27	397.7-CPD	6					
28	398	3,611					
29	SUBTOTAL	303,279					
30							
31	TOTAL	11,150,035					
32							
33							
34							
35	SEE FOOTNOTE						
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 3 Column: b

Nuclear Production Plant includes only $8,070,000 of nuclear decommissioning expense.

Schedule Page: 336 Line No.: 12 Column: f

Reclassification of 2015 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	-	22,028,386	-	22,028,386
Steam Production	19,354,048	-	-	19,354,048
Nuclear Production	8,070,000	-	-	8,070,000
Other Production	18,780,079	-	2,148	18,782,227
Transmission Plant	114,457,681	-	1,919,789	116,377,470
Distribution Plant	207,374,720	-	1,875,840	209,250,560
General Plant	12,105,160	-	-	12,105,160
Common Plant-Electric	25,309,844	30,186,281	-	55,496,125
Total Ratemaking Depreciation & Amort.	405,451,532	52,214,667	3,797,777	461,463,976

Schedule Page: 336.2 Line No.: 35 Column: b

Items in column (b) are 12/31/2015 weighted plant balances based on 12/31/2014 plant balances (Account 101) plus weighted net additions for 2015 less non-depreciables for each plant account.

All other lines, Cols. C-G: no change.

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

REGULATORY COMMISSION EXPENSES

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1	D. 14-12-062 2012-2014 "CARE" & "ESA"		4,533	4,533	
2			629	629	
3					
4	D. 14-12-063 2012-2014 "CARE" & "ESA"		959	959	
5			133	133	
6					
7	D. 14-12-064 UPDATE COSTS AND RATE DESIGN		163,904	163,904	
8					
9	D. 14-12-067 PROCUREMENT POLICIES		2,219	2,219	
10					
11	D. 14-12-071 RESOURCE ADEQUACY PROGRAM		3,918	3,918	
12					
13	D. 14-12-072 COST OF CAPITAL		8,028	8,028	
14			1,114	1,114	
15					
16	D. 14-12-074 RESOURCE ADEQUACY PROGRAM		6,678	6,678	
17					
18	D. 14-12-075 RESOURCE ADEQUACY PROGRAM		2,023	2,023	
19					
20	D. 14-12-076 GREENHOUSE GAS EMISSIONS		928	928	
21			153	153	
22					
23	D. 14-12-077 GREENHOUSE GAS EMISSIONS		1,501	1,501	
24			247	247	
25					
26	D. 15-01-015 PROCUREMENT POLICIES		14,471	14,471	
27					
28	D. 15-01-016 ENERGY EFFICIENCY RISK/REWARD		5,344	5,344	
29			742	742	
30					
31	D. 15-01-017 2012-2014 "CARE" & "ESA"		11,098	11,098	
32			1,540	1,540	
33					
34	D. 15-01-043 EXPIRATION OF RATEPAYER		1,652	1,652	
35			229	229	
36					
37	D. 15-01-044 RESOURCE ADEQUACY PROGRAM		3,686	3,686	
38					
39	D. 15-01-045 RESOURCE ADEQUACY PROGRAM		3,002	3,002	
40					
41	D. 15-01-046 RESOURCE ADEQUACY PROGRAM		1,006	1,006	
42					
43	D. 15-02-037 ENERGY STORAGE SYSTEMS		2,339	2,339	
44					
45					
46	TOTAL	5,025,374	14,025,060	19,050,434	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

REGULATORY COMMISSION EXPENSES

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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	D. 15-02-038 ENERGY EFFICIENCY PROGRAMS		637	637	
2			88	88	
3					
4	D. 15-02-039 BIOMETHANE STANDARDS		1,713	1,713	
5					
6	D. 15-03-011 ENERGY EFFICIENCY PROGRAMS		1,846	1,846	
7			256	256	
8					
9	D. 15-03-013 RESIDENTIAL RATE STRUCTURES		5,478	5,478	
10					
11	D. 15-03-034 ENERGY STORAGE SYSTEMS		7,214	7,214	
12					
13	D.15-03-035 MKTG, EDU & OUTREACH PROGRAM		2,338	2,338	
14			384	384	
15					
16	D. 15-03-039 MKTG, EDU & OUTREACH PROGRAM		4,748	4,748	
17			780	780	
18					
19	D. 15-03-040 MKTG, EDU & OUTREACH PROGRAM		714	714	
20			117	117	
21					
22	D. 15-04-015 SMART GRID SYSTEM		3,930	3,930	
23			646	646	
24					
25	D. 15-04-016 ENERGY STORAGE SYSTEMS		3,425	3,425	
26					
27	D. 15-04-017 UPDATE COSTS AND RATE DESIGN		57,667	57,667	
28					
29	D. 15-04-018 UPDATE COSTS AND RATE DESIGN		40,149	40,149	
30					
31	D 15-05-016 ENERGY STORAGE SYSTEMS		1,864	1,864	
32					
33	D. 15-05-017 CALIFORNIA RENEWABLE PORTFOLIO		5,401	5,401	
34					
35	D. 15-08-018 RESIDENTIAL RATE STRUCTURES		2,813	2,813	
36					
37	D. 15-05-019 UPDATE COSTS AND RATE DESIGN		69,578	69,578	
38					
39	D. 15-05-020 UPDATE COSTS AND RATE DESIGN		10,802	10,802	
40					
41	D. 15-05-021 SMART GRID SYSTEM		3,503	3,503	
42					
43	D. 15-05-022 CA RENEWABLE PORTFOLIO		340	340	
44					
45					
46	TOTAL	5,025,374	14,025,060	19,050,434	

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	/ /	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

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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	D. 15-05-023 UPDATE COSTS AND RATE DESIGN		58,469	58,469	
2					
3	D. 15-05-026 RESOURCE ADEQUACY PROGRAM		4,790	4,790	
4					
5	D.15-06-011 2012-2014 "CARE" & "ESA"		3,286	3,286	
6			436	436	
7					
8	D. 15-06-012 2012-2014 "CARE" & "ESA"		4,644	4,644	
9			616	616	
10					
11	D. 15-06-013 2012-2014 "CARE" & "ESA"		1,482	1,482	
12			197	197	
13					
14	D. 15-06-014 2012-2014 "CARE" & "ESA"		3,437	3,437	
15			456	456	
16					
17	D. 15-06-017 CA RENEWABLE PORTFOLIO		3,313	3,313	
18					
19	D. 15-06-020 PROCUREMENT POLICIES		20,946	20,946	
20					
21	D. 15-06-021 PROCUREMENT POLICIES		26,557	26,557	
22					
23	D. 15-06-022 PROCUREMENT POLICIES		3,159	3,159	
24					
25	D. 15-06-023 PROCUREMENT POLICIES		1,632	1,632	
26					
27	D. 15-06-025 PROCUREMENT POLICIES		3,414	3,414	
28					
29	D. 15-06-026 PROCUREMENT POLICIES		11,864	11,864	
30					
31	D. 15-06-027 PROCUREMENT POLICIES		868	868	
32					
33	D. 15-06-055 PROCUREMENT POLICIES		1,879	1,879	
34					
35	D. 15-06-056 PROCUREMENT POLICIES		9,255	9,255	
36					
37	D. 15-06-058 ENERGY STORAGE PROCUREMENT		5,192	5,192	
38					
39	D. 15-06-060 ENERGY EFFICIENCY RISK/REWARD		7,486	7,486	
40			1,039	1,039	
41					
42	D. 15-06-061 SMART GRID SYSTEM		2,607	2,607	
43					
44	D. 15-07-018 PROCUREMENT POLICIES		34,714	34,714	
45					
46	TOTAL	5,025,374	14,025,060	19,050,434	

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REGULATORY COMMISSION EXPENSES

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1	D.15-07-019 2012-2014 "CARE" & "ESA"		6,223	6,223	
2			1,023	1,023	
3					
4	D. 15-07-020 INCREASE RATES & CHARGES		1,610	1,610	
5					
6	D. 15-07-021 ELEC & NAT GAS SERV DISCONNECT		1,927	1,927	
7			256	256	
8					
9	D. 15-07-022 ELEC & NAT GAS SERV DISCONNECT		2,958	2,958	
10			393	393	
11					
12	D. 15-07-023 DIST LEVEL INTERCONNECT RULES		10,018	10,018	
13					
14	D. 15-07-024 CALIFORNIA SOLAR INITIATIVE		1,760	1,760	
15			289	289	
16					
17	D. 15-07-025 ENERGY STORAGE SYSTEMS		13,526	13,526	
18					
19	D. 15-07-026 ENERGY STORAGE PROCUREMENT		6,644	6,644	
20					
21	D. 15-07-028 ENERGY STORAGE PROCUREMENT		3,417	3,417	
22					
23	D. 15-07-029 ENERGY STORAGE PROCUREMENT		1,718	1,718	
24					
25	D. 15-07-030 GENERAL RATE CASE PLAN		1,656	1,656	
26			220	220	
27					
28	D. 15-07-031 GENERAL RATE CASE PLAN		2,374	2,374	
29			315	315	
30					
31	D. 15-07-032 GENERAL RATE CASE PLAN		11,484	11,484	
32			1,524	1,524	
33					
34	D. 15-07-033 GENERAL RATE CASE PLAN		4,132	4,132	
35			548	548	
36					
37	D. 15-07-034 ELEC & NAT GAS SERV DISCONNECT		4,150	4,150	
38			551	551	
39					
40	D. 15-07-035 ELEC & NAT GAS SERV DISCONNECT		946	946	
41			126	126	
42					
43	D. 15-07-036 2012-2014 "CARE" & "ESA"		1,997	1,997	
44			265	265	
45					
46	TOTAL	5,025,374	14,025,060	19,050,434	

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1	D. 15-08-018 SMART GRID DEPLOYMENT PLAN		2,089	2,089	
2					
3	D. 15-08-019 SMARTMETER PROGRAM		9,696	9,696	
4			1,346	1,346	
5					
6	D. 15-08-020 SMARTMETER PROGRAM		6,876	6,876	
7			954	954	
8					
9	D. 15-08-021 CA RENEWABLE PORTFOLIO		1,294	1,294	
10					
11	D. 15-08-024 GREENHOUSE GAS EMISSIONS		8,361	8,361	
12			1,529	1,529	
13					
14	D. 15-08-025 GREENHOUSE GAS EMISSIONS		4,810	4,810	
15			790	790	
16					
17	D. 15-08-038 SMARTMETER PROGRAM		3,291	3,291	
18			457	457	
19					
20	D. 15-08-039 SMARTMETER PROGRAM		5,073	5,073	
21			704	704	
22					
23	D. 15-09-016 DEMAND RESPONSE		10,662	10,662	
24					
25	D. 15-09-018 PROCUREMENT POLICIES		2,559	2,559	
26					
27	D. 15-09-019 SOLAR GENERATED ELECTRICITY		2,756	2,756	
28					
29	D. 15-09-020 GREENHOUSE GAS EMISSIONS		2,327	2,327	
30			309	309	
31					
32	D. 15-10-006 ELEC VEHICLE-GRID INTEGRATION		3,336	3,336	
33			443	443	
34					
35	D. 15-10-007 CA RENEWABLE PORTFOLIO		456	456	
36					
37	D. 15-10-008 DEMAND RESPONSE		31,137	31,137	
38					
39	D. 15-10-009 DEMAND RESPONSE		9,551	9,551	
40					
41	D. 15-10-010 DEMAND RESPONSE		19,232	19,232	
42					
43	D. 15-10-011 SOLAR GENERATED ELECTRICITY		8,502	8,502	
44					
45	D. 15-10-012 SOLAR GENERATED ELECTRICITY		4,839	4,839	
46	TOTAL	5,025,374	14,025,060	19,050,434	

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1	D. 15-10-013 CA RENEWABLE PORTFOLIO		1,728	1,728	
2			229	229	
3					
4	D. 15-10-014 CA RENEWABLE PORTFOLIO		2,369	2,369	
5			314	314	
6					
7	D. 15-010-015 CA RENEWABLE PORTFOLIO		3,611	3,611	
8			594	594	
9					
10	D. 15-10-016 CA RENEWABLE PORTFOLIO		1,371	1,371	
11			182	182	
12					
13	D. 15-10-017 CA RENEWABLE PORTFOLIO		1,589	1,589	
14			211	211	
15					
16	D. 15-10-018 CA RENEWABLE PORTFOLIO		19,596	19,596	
17			2,601	2,601	
18					
19	D. 15-10-041 ENERGY EFFICIENCY PROGRAMS		2,548	2,548	
20			338	338	
21					
22	D. 15-10-042 PURCHASE POWER TOLLING		16,009	16,009	
23					
24	D. 15-10-044 DEMAND RESPONSE		7,952	7,952	
25					
26	D. 15-10-045 CA RENEWABLE PORTFOLIO		4,123	4,123	
27					
28	D. 15-10-046 DEMAND RESPONSE		1,917	1,917	
29					
30	D. 15-10-048 CA RENEWABLE PORTFOLIO		3,883	3,883	
31					
32	D. 15-11-016 SOLAR GENERATED ELECTRICTY		2,966	2,966	
33					
34	D. 15-11-019 2012 NUCLEAR DECOMMISSIONING		30,906	30,906	
35			5,080	5,080	
36					
37	D. 15-11-020 CA RENEWABLE PORTFOLIO		2,145	2,145	
38			285	285	
39					
40	D. 15-11-035 2012 NUCLEAR DECOMMISSIONING		7,067	7,067	
41			1,162	1,162	
42					
43	D. 15-11-036 RESIDENTIAL RATE REFORM		35,628	35,628	
44					
45	D. 15-11-037 GREENHOUSE GAS EMISSIONS		1,117	1,117	
46	TOTAL	5,025,374	14,025,060	19,050,434	

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1	D. 15-11-038 UPDATE COSTS AND RATE DESIGN		27,878	27,878	
2					
3	D. 15-11-039 CA RENEWABLE PORTFOLIO		3,220	3,220	
4			529	529	
5					
6	D. 15-11-040 SAN ONOFRE NUCLEAR GEN STATION		53,815	53,815	
7					
8	CALIFORNIA PUBLIC UTILITIES COMMISSION FEES	4,585,836		4,585,836	
9		439,538		439,538	
10					
11	FERC PROCEEDINGS		5,079	5,079	
12			30,709	30,709	
13					
14	SETTLEMENT REFUND LITIGATION RESOLUTION		80,447	80,447	
15					
16	MISCELLANEOUS		9,834,554	9,834,554	
17			2,925,634	2,925,634	
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					
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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
Elec	928	4,533					1
Gas	928	629					2
							3
Elec	928	959					4
Gas	928	133					5
							6
Elec	928	163,904					7
							8
Elec	928	2,219					9
							10
Elec	928	3,918					11
							12
Elec	928	8,028					13
Gas	928	1,114					14
							15
Elec	928	6,678					16
							17
Elec	928	2,023					18
							19
Elec	928	928					20
Gas	928	153					21
							22
Elec	928	1,501					23
Gas	928	247					24
							25
Elec	928	14,471					26
							27
Elec		5,344					28
Gas		742					29
							30
Elec	928	11,098					31
Gas	928	1,540					32
							33
Elec	928	1,652					34
Gas	928	229					35
							36
Elec	928	3,686					37
							38
Elec	928	3,002					39
							40
Elec	928	1,006					41
							42
Elec	928	2,339					43
							44
							45
		19,050,434					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	/ /	End of 2015/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.
Elec	928	637					1
Gas	928	88					2
							3
Gas	928	1,713					4
							5
Elec	928	1,846					6
Gas	928	256					7
							8
Elec	928	5,478					9
							10
Elec	928	7,214					11
							12
Elec	928	2,338					13
Gas	928	384					14
							15
Elec	928	4,748					16
Gas	928	780					17
							18
Elec	928	714					19
Gas	928	117					20
							21
Elec	928	3,930					22
Gas	928	646					23
							24
Elec	928	3,425					25
							26
Elec	928	57,667					27
							28
Elec	928	40,149					29
							30
Elec	928	1,864					31
							32
Elec	928	5,401					33
							34
Elec	928	2,813					35
							36
Elec	928	69,578					37
							38
Elec	928	10,802					39
							40
Elec	928	3,503					41
							42
Elec	928	340					43
							44
							45
		19,050,434					46

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			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
Elec	928	58,469					1
							2
Elec	928	4,790					3
							4
Elec	928	3,286					5
Gas	928	436					6
							7
Elec	928	4,644					8
Gas	928	616					9
							10
Elec	928	1,482					11
Gas	928	197					12
							13
Elec	928	3,437					14
Gas	928	456					15
							16
Elec	928	3,313					17
							18
Elec	928	20,946					19
							20
Elec	928	26,557					21
							22
Elec	928	3,159					23
							24
Elec	928	1,632					25
							26
Elec	928	3,414					27
							28
Elec	928	11,864					29
							30
Elec	928	868					31
							32
Elec	928	1,879					33
							34
Elec	928	9,255					35
							36
Elec	928	5,192					37
							38
Elec	928	7,486					39
Gas	928	1,039					40
							41
Elec	928	2,607					42
							43
Elec	928	34,714					44
							45
		19,050,434					46

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.
Elec	928	6,223					1
Gas	928	1,023					2
							3
Elec	928	1,610					4
							5
Elec	928	1,927					6
Gas	928	256					7
							8
Elec	928	2,958					9
Gas	928	393					10
							11
Elec	928	10,018					12
							13
Elec	928	1,760					14
Gas	928	289					15
							16
Elec	928	13,526					17
							18
Elec	928	6,644					19
							20
Elec	928	3,417					21
							22
Elec	928	1,718					23
							24
Elec	928	1,656					25
Gas	928	220					26
							27
Elec	928	2,374					28
Gas	928	315					29
							30
Elec	928	11,484					31
Gas	928	1,524					32
							33
Elec	928	4,132					34
Gas	928	548					35
							36
Elec	928	4,150					37
Gas	928	551					38
							39
Elec	928	946					40
Gas	928	126					41
							42
Elec	928	1,997					43
Gas	928	265					44
							45
		19,050,434					46

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.
Elec	928	2,089					1
							2
Elec	928	9,696					3
Gas	928	1,346					4
							5
Elec	928	6,876					6
Gas	928	954					7
							8
Elec	928	1,294					9
							10
Elec	928	8,361					11
Gas	928	1,529					12
							13
Elec	928	4,810					14
Gas	928	790					15
							16
Elec	928	3,291					17
Gas	928	457					18
							19
Elec	928	5,073					20
Gas	928	704					21
							22
Elec	928	10,662					23
							24
Elec	928	2,559					25
							26
Elec	928	2,756					27
							28
Elec	928	2,327					29
Gas	928	309					30
							31
Elec	928	3,336					32
Gas	928	443					33
							34
Elec	928	456					35
							36
Elec	928	31,137					37
							38
Elec	928	9,551					39
							40
Elec	928	19,232					41
							42
Elec	928	8,502					43
							44
Elec	928	4,839					45
		19,050,434					46

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.
Elec	928	1,728					1
Gas	928	229					2
							3
Elec	928	2,369					4
Gas	928	314					5
							6
Elec	928	3,611					7
Gas	928	594					8
							9
Elec	928	1,371					10
Gas	928	182					11
							12
Elec	928	1,589					13
Gas	928	211					14
							15
Elec	928	19,596					16
Gas	928	2,601					17
							18
Elec	928	2,548					19
Gas	928	338					20
							21
Elec	928	16,009					22
							23
Elec	928	7,952					24
							25
Elec	928	4,123					26
							27
Elec	928	1,917					28
							29
Elec	928	3,883					30
							31
Elec	928	2,966					32
							33
Elec	928	30,906					34
Gas	928	5,080					35
							36
Elec	928	2,145					37
Gas	928	285					38
							39
Elec	928	7,067					40
Gas	928	1,162					41
							42
Elec	928	35,628					43
							44
Elec	928	1,117					45
		19,050,434					46

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.
Gas	928	27,878					1
							2
Elec	928	3,220					3
Gas	928	529					4
							5
Elec	928	53,815					6
							7
Elec	928	-201,407					8
Gas	928	-6,840					9
							10
Elec	928	5,079					11
Gas	928	30,709					12
							13
Elec	928	80,447					14
							15
Elec	928	14,621,797					16
Gas	928	3,372,012					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
		19,050,434					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	/ /	End of 2015/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 $50,000.)
- (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	NONE
2		
3	(1) Generation	NONE
4		
5	(2) System Planning, Engineering and Operation	NONE
6		
7	(3) Transmission	NONE
8		
9	(4) Distribution	RD&D Performed Internally
10		
11	(5) Environment	NONE
12		
13	(6) Other	NONE
14		
15	(7) Sub Total Internal Costs Incurred	NONE
16		
17	B. External	
18		
19	(1) Research Support to the Electrical	Collaborative Memberships with EPRI
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	CPUC and California Energy Commission
28		
29	(5) Sub Total External Costs Incurred	NONE
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	/ /	End of 2015/Q4

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 $50,000 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 $50,000 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)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
10,103,409		930.2	10,103,409		9
					10
					11
					12
					13
					14
10,103,409			10,103,409		15
					16
					17
					18
	1,038,654	930.2	1,038,654		19
					20
					21
					22
					23
					24
					25
					26
	17,420,986	588.0	17,420,986		27
					28
	18,459,640		18,459,640		29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Schedule Page: 352 Line No.: 1 Column: a

Per the FERC Audit, Docket No. FA12-8-000, the following disclosure is required:

- There have been inconsistent accounting and reporting of RD&D for the past several years relating to page 352-353.

This issue has no financial impact on our financial statements.

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	10,952,626		
4	Transmission	12,049,458		
5	Regional Market			
6	Distribution	35,536,663		
7	Customer Accounts	17,215,796		
8	Customer Service and Informational	21,388,365		
9	Sales			
10	Administrative and General	39,144,291		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	136,287,199		
12	Maintenance			
13	Production	1,849,139		
14	Transmission	8,410,427		
15	Regional Market			
16	Distribution	13,282,839		
17	Administrative and General	1,360,782		
18	TOTAL Maintenance (Total of lines 13 thru 17)	24,903,187		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,801,765		
21	Transmission (Enter Total of lines 4 and 14)	20,459,885		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	48,819,502		
24	Customer Accounts (Transcribe from line 7)	17,215,796		
25	Customer Service and Informational (Transcribe from line 8)	21,388,365		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	40,505,073		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	161,190,386	46,185,194	207,375,580
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	57,078		
35	Transmission	1,812,506		
36	Distribution	17,751,986		
37	Customer Accounts	8,404,006		
38	Customer Service and Informational	2,880,633		
39	Sales			
40	Administrative and General	12,312,264		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	43,218,473		
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	3,460,490		

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	5,208,447		
49	Administrative and General	429,269		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	9,098,206		
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)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	57,078		
56	Transmission (Lines 35 and 47)	5,272,996		
57	Distribution (Lines 36 and 48)	22,960,433		
58	Customer Accounts (Line 37)	8,404,006		
59	Customer Service and Informational (Line 38)	2,880,633		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	12,741,533		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	52,316,679	13,740,286	66,056,965
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	213,507,065	59,925,480	273,432,545
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	58,126,178	105,650,392	163,776,570
69	Gas Plant	10,853,711	15,707,506	26,561,217
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	68,979,889	121,357,898	190,337,787
72	Plant Removal (By Utility Departments)			
73	Electric Plant	7,457,421	11,948,439	19,405,860
74	Gas Plant	332,612	288,614	621,226
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	7,790,033	12,237,053	20,027,086
77	Other Accounts (Specify, provide details in footnote):			
78	3rd Party Billings, Gas	6,899	1,131,695	1,138,594
79	3rd Party Billings, Electric	772,822	4,049,836	4,822,658
80	Affiliate Billings, Gas		8,272,804	8,272,804
81	Affiliate Billings, Electric		26,139,860	26,139,860
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	779,721	39,594,195	40,373,916
96	TOTAL SALARIES AND WAGES	291,056,708	233,114,626	524,171,334

Schedule Page: 354 Line No.: 96 Column: d

FERC 426 is not included in the detail classification lines or summary totals. FERC 426 for 2015 amounts to $1,035,658.39

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	261,401,078	64,811,970	2,074,791			324,138,257
389 Land & Land Rights	8,249,876					8,249,876
390 Structures & Improvements	303,527,988	40,091,261	5,075,756			338,543,493
391 Office Furniture & Equipment	111,689,753	3,584,206	34,849,622			80,424,337
392 Transportation Equipment	67,312		21,173			46,139
393 Stores Equipment	79,141		15,170			63,971
394 Tools, Shop & Garage Equip.	2,511,051	40,358	9,901			2,541,508
395 Laboratory Equipment	2,090,236		92,257			1,997,979
396 Power Operated Equipmennt						
397 Communication Equipment	135,304,341	63,143,354	4,234,286			194,213,409
398 Miscellaneous Equipment	2,481,414		193,595			2,287,819
SPL Topside	(239,322)			239,322		
FIN 47 ARC - Common	1,088,265			2,365,142		3,453,407
Fleet Capital Lease	19,162,908	1,026,148				20,189,056
TOTAL COMMON PLANT	847,414,041	172,697,298	46,566,551	2,604,464		976,149,251
Construction Work in Progress	150,483,747	(73,140,949)				77,342,798
TOTAL COMMON PLANT	997,897,788	99,556,349	46,566,551	2,604,464		1,053,492,049

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	/ /	End of 2015/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, 2015 Accumulated Depreciation
303 Misc. Intangible Plant	208,007,908
389 Land & Land Rights	27,776
390 Structures & Improvements	137,925,564
391 Office Furniture & Equipment	46,106,070
392 Transportation Equipment	(334,610)
393 Stores Equipment	49,449
394 Tools, Shop & Garage Equipment	638,702
395 Laboratory Equipment	918,761
396 Power Operated Equipment	(192,979)
397 Communication Equipment	70,998,629
398 Miscellaneous Equipment	1,472,662
108.4 Retirement Work in Progress	
FIN 47 Accumulated Depreciation	(26,068)
Fleet Capital Lease	19,590,319
Total Accumulated Depreciation	485,182,183

Split of Common Utility Plant to Departments: (excluding CWIP) (see Note 2- Page 356.2)		December 31,2015 Balance End of Year	Accumulated Depreciation
Electric	75.96%	741,482,971	368,544,386
Gas	24.04%	234,666,280	116,637,797
Total	100.00%	976,149,251	485,182,183

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		39,739,706
389	Land & Land Rights		
390	Structures & Improvements		12,411,765
391	Office Furniture & Equipment		7,513,761
392	Transportation Equipment		2,224
393	Stores Equipment		7,523
394	Tools, Shop & Garage Equipment		159,319
395	Laboratory Equipment		84,874
396	Power Operated Equipment		
397	Communication Equipment		12,923,824
398	Miscellaneous Equipment		216,673
	Total	4,694,611	73,059,669

(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 2014-2015 and 2015-2016. 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 labor ratios in accordance with allocation procedures proposed by the California Public Utilities Commission. These rates were revised in January 2015.
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	/ /	End of 2015/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)	144,710,054	270,329,601	470,478,126	626,231,540
3	Net Sales (Account 447)	(99,024,410)	(208,614,195)	(394,441,598)	(526,778,962)
4	Transmission Rights				
5	Ancillary Services	774,957	1,484,141	2,588,331	3,617,147
6	Other Items (list separately)				
7	Congestion	676,236	1,227,686	2,778,276	3,840,914
8	CRR (Congestion Revenue Rights)	(11,254,679)	(11,769,517)	(16,216,795)	(20,975,551)
9	GMC (Grid Management Charges)	2,736,135	5,547,346	9,258,603	12,683,241
10	Other	(2,887,112)	(285,815)	3,165,027	2,903,204
11	UFE (Unaccounted for Energy)	1,330,522	(8,101,768)	(8,732,349)	(12,382,305)
12					
13					
14					
15					
16					
17					
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40					
41					
42					
43					
44					
45					
46	TOTAL	37,061,703	49,817,479	68,877,621	89,139,228

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	1,328,300	MWH	4,253,134	174,976	MWH	635,987
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)	1,328,300		4,253,134	174,976		635,987

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	/ /	End of 2015/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	2,976	2	17	2,976					
2	February	2,966	12	17	2,966					
3	March	3,120	16	18	3,120					
4	Total for Quarter 1				9,062					
5	April	3,111	30	15	3,111					
6	May	3,092	1	15	3,092					
7	June	3,367	30	12	3,367					
8	Total for Quarter 2				9,570					
9	July	3,607	24	15	3,607					
10	August	4,423	28	15	4,423					
11	September	4,711	9	14	4,711					
12	Total for Quarter 3				12,741					
13	October	4,312	9	15	4,312					
14	November	3,090	30	18	3,090					
15	December	3,215	14	17	3,215					
16	Total for Quarter 4				10,617					
17	Total Year to Date/Year				41,990					

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	/ /	End of 2015/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									

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	/ /	End of 2015/Q4

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	5,185,431
4	Nuclear	
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	93,385
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	5,278,816
10	Purchases	29,430,376
11	Power Exchanges:	
12	Received	1,142,434
13	Delivered	1,142,434
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)	34,709,192

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	16,267,013
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	16,865,020
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	32,899
27	Total Energy Losses	1,544,260
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	34,709,192

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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 in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: San Diego Gas & Electric

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,365,357	1,080,826	2,976	2	17
30	February	1,262,081	940,555	2,966	12	17
31	March	1,205,366	1,066,256	3,120	16	18
32	April	1,227,334	946,180	3,111	30	15
33	May	1,216,318	1,259,956	3,092	1	15
34	June	1,201,038	1,476,503	3,367	30	12
35	July	1,401,089	2,087,543	3,607	24	15
36	August	1,468,324	1,660,551	4,423	28	15
37	September	1,604,995	1,668,431	4,711	9	14
38	October	1,588,116	1,972,619	4,312	9	15
39	November	1,371,034	1,150,171	3,090	30	18
40	December	1,355,961	1,555,429	3,215	14	17
41	TOTAL	16,267,013	16,865,020			

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	/ /	End of 2015/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: *Palomar* (b)	Plant Name: *Miramar* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle	Gas Turbine (2)
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor	Semi-Outdoor
3	Year Originally Constructed	2006	2005
4	Year Last Unit was Installed	2006	2009
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	559.00	95.00
6	Net Peak Demand on Plant - MW (60 minutes)	566	96
7	Plant Hours Connected to Load	6749	1362
8	Net Continuous Plant Capability (Megawatts)	559	95
9	When Not Limited by Condenser Water	559	95
10	When Limited by Condenser Water	0	95
11	Average Number of Employees	29	3
12	Net Generation, Exclusive of Plant Use - KWh	2998816000	81436000
13	Cost of Plant: Land and Land Rights	14480000	0
14	Structures and Improvements	72337179	5075863
15	Equipment Costs	499372726	96602882
16	Asset Retirement Costs	0	0
17	Total Cost	586189905	101678745
18	Cost per KW of Installed Capacity (line 17/5) Including	1048.6403	1070.3026
19	Production Expenses: Oper, Supv, & Engr	1182851	82543
20	Fuel	70452647	2864536
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	4709895	150715
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	4621901	283451
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	690	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	5311	0
30	Maintenance of Structures	69641	71
31	Maintenance of Boiler (or reactor) Plant	1343336	0
32	Maintenance of Electric Plant	-2684716	1670266
33	Maintenance of Misc Steam (or Nuclear) Plant	6780032	535065
34	Total Production Expenses	86481588	5586647
35	Expenses per Net KWh	0.0288	0.0686

Line No.	Item (a)	Palomar (b)			Miramar (c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	20527311	0	0	798092	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	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	3.432	0.000	0.000	3.589	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.358	0.000	0.000	3.512	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.035	0.000	0.000
44	Average BTU per KWh Net Generation	7030.000	0.000	0.000	10065.000	0.000	0.000

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	/ /	End of 2015/Q4

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: *Desert Star* (d)	Plant Name: *Cuyamaca* (e)	Plant Name: (f)	Line No.
Combined Cycle	Gas Turbine		1
Semi-Outdoor	Semi-Outdoor		2
2000	2002		3
2000	2002		4
536.00	47.00	0.00	5
485	47	0	6
8760	261	0	7
450	47	0	8
450	47	0	9
450	47	0	10
23	1	0	11
2184594000	10281000	0	12
0	0	0	13
30781723	1865081	0	14
296115627	15008162	0	15
1264472	0	0	16
328161822	16873243	0	17
612.2422	359.0052	0	18
1027079	0	0	19
55647446	524454	0	20
0	0	0	21
1886160	9828	0	22
0	0	0	23
0	0	0	24
895205	109323	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	1275	0	30
2975494	0	0	31
16253030	235890	0	32
1211457	-97885	0	33
79895871	782885	0	34
0.0366	0.0761	0.0000	35

(d)			(e)			(f)			Line No.
GAS			GAS						36
MCF			MCF						37
15852987	0	0	113799	0	0	0	0	0	38
0	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
3.510	0.000	0.000	4.609	0.000	0.000	0.000	0.000	0.000	41
3.435	0.000	0.000	4.509	0.000	0.000	0.000	0.000	0.000	42
0.025	0.000	0.000	0.051	0.000	0.000	0.000	0.000	0.000	43
7453.000	0.000	0.000	11368.000	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	/ /	End of 2015/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

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	/ /	End of 2015/Q4

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)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
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			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	/ /	End of 2015/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	J & D Labs Fuel Cell	2012	0.40	0.4	2,634	3,041,785
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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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	/ /	End of 2015/Q4

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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
7,604,463		102,612		Gas	424	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
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						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	/ /	End of 2015/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		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	East County	500.00	500.00	3,1s	52.96		1
2	Imperial Valley		500.00	500.00	3	51.50		1
3		Colorado River	500.00	500.00	1S	24.00		1
4	Colorado River	North Gila	500.00	500.00	1S	5.63		1
5	North Gila	Palo Verde	500.00	500.00	3	114.45		1
6	Suncrest	Ocotillo Switchyard	500.00	500.00	3	67.46		1
7	East County	Imperial Valley	500.00	500.00	3,1S	30.94		1
8	Ocotillo Switchyard	Imperial Valley	500.00	500.00	3	21.60		1
9	Ocotillo Switchyard	Ocotillo Express Sub	500.00	500.00	3	0.06		1
10	Total 500KV Pole Line Miles					368.60		9
11								
12	San Luis Rey Tap		230.00	230.00	3		5.29	2
13			230.00	230.00	3	26.45		2
14		Mission	230.00	230.00	2W	3.26		1
15	San Luis Rey		230.00	230.00	3	0.11		1
16			230.00	230.00	2S	0.49		2
17			230.00	230.00	2W	1.00		1
18		San Onofre	230.00	230.00	3	16.26		2
19	San Luis Rey		230.00	230.00	3	5.75		1
20		Encina	230.00	230.00	3	1.47		1
21	San Luis Rey		230.00	230.00	2W	2.34		1
22			230.00	230.00	3		26.58	2
23		Mission	230.00	230.00	2W		3.26	1
24	San Luis Rey	San Onofre	230.00	230.00	3	18.12		2
25	San Onofre		230.00	230.00	2S	0.47		2
26			230.00	230.00	3	6.00		2
27		Talega	230.00	230.00	3	0.43		1
28	San Onofre		230.00	230.00	3		16.82	2
29			230.00	230.00	2W	0.78		1
30			230.00	230.00	1S	0.63		2
31		Encina	230.00	230.00	3		1.90	2
32	Encina	Encina Hub	230.00	230.00	1S		1.44	2
33	Encina Hub	San Luis Rey	230.00	230.00	3		5.87	2
34	Encina Hub		230.00	230.00	1S,3		0.73	2
35			230.00	230.00	1S		0.06	2
36					TOTAL	1,706.80	414.63	583

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	/ /	End of 2015/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1			230.00	230.00	3		0.90	2
2			230.00	230.00	3		5.96	2
3		Palomar	230.00	230.00	1S		0.80	2
4	Encina		230.00	230.00	1S		1.44	2
5			230.00	230.00	3		1.00	1
6			230.00	230.00	3		3.43	2
7			230.00	230.00	1S		10.34	2
8			230.00	230.00	1S		2.00	2
9		Penasquitos	230.00	230.00	1S	0.10		1
10	Penasquitos		230.00	230.00	1S	11.05		1
11		Old Town	230.00	230.00	1S	0.47		1
12	Palomar		230.00	230.00	1S		0.16	1
13		Escondido	230.00	230.00	1S		0.22	1
14	Palomar Generator		230.00	230.00	1S	0.16	0.16	2
15		Escondido	230.00	230.00	1S	0.21	0.22	2
16	East County	ECO GEN 1	230.00	230.00	1S	0.15	0.15	2
17	Miguel		230.00	230.00	3	23.91		2
18			230.00	230.00	3	3.42		1
19		Sycamore Canyon	230.00	230.00	1S	0.56		1
20	Miguel		230.00	230.00	3		23.91	2
21			230.00	230.00	3	3.02		1
22		Mission	230.00	230.00	1S	6.70		1
23	Miguel		230.00	230.00	3	7.52		1
24			230.00	230.00	1S	14.78		1
25		Mission	230.00	230.00	3	9.11		1
26			230.00	230.00	3	2.04		1
27	Old Town	Mission	230.00	230.00	1S	3.86		2
28	Old Town	Mission	230.00	230.00	1S		3.85	2
29	Silvergate		230.00	230.00	4	0.69		1
30			230.00	230.00	4	0.31		1
31			230.00	230.00	4	5.04		1
32			230.00	230.00	4	0.26		1
33		Old Town	230.00	230.00	4	0.99		1
34	Silvergate		230.00	230.00	4	0.69		1
35			230.00	230.00	4	0.31		1
36					TOTAL	1,706.80	414.63	583

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
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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	4	5.04		1
2			230.00	230.00	4	0.26		1
3		Old Town	230.00	230.00	4	0.99		1
4	Escondido		230.00	230.00	1S	5.02		1
5		Talega	230.00	230.00	3	46.03		1
6	Otay Mesa		230.00	230.00	1S	0.10		1
7		Tijuana	230.00	230.00	3	1.61		1
8	Otay Mesa	Miguel	230.00	230.00	3, 1S		8.92	2
9	Miguel		230.00	230.00	1S		24.61	2
10			230.00	230.00	3		0.67	2
11		Sycamore	230.00	230.00	3		3.62	2
12	Otay Mesa	Miguel	230.00	230.00	3, 1S		8.92	2
13	Miguel		230.00	230.00	1S		9.59	2
14			230.00	230.00	4	2.26		1
15			230.00	230.00	4	0.76		1
16			230.00	230.00	4	0.03		1
17			230.00	230.00	3		3.85	1
18		Silver Gate	230.00	230.00	4	0.40		1
19	Imperial Valley		230.00	230.00	1S	0.04		1
20		IV Gen 3	230.00	230.00	1S	1.36		1
21	Imperial Valley		230.00	230.00	2W	0.82		1
22		La Rosita	230.00	230.00	3	4.64		1
23	Palomar		230.00	230.00	1S		0.80	1
24			230.00	230.00	3		5.96	2
25			230.00	230.00	3	10.12		1
26			230.00	230.00	1S	4.75		1
27			230.00	230.00	3	1.55		1
28		Sycamore Canyon	230.00	230.00	1S	0.17		1
29	San Onofre		230.00	230.00	2S		0.47	2
30	San Onofre	Talega	230.00	230.00	3		6.43	1
31	Penasquitos		230.00	230.00	1S		10.04	2
32		Encina	230.00	230.00	3		8.09	2
33	Sycamore Canyon	Suncrest	230.00	230.00	3	21.77		2
34	Sycamore Canyon	Suncrest	230.00	230.00	3	21.77		2
35	Imperial Valley	Drew Switchyard	230.00	230.00	3, 1S	5.33		2
36					TOTAL	1,706.80	414.63	583

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
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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	Drew Switchyard		230.00	230.00	1S	1.10		1
2		DW Gen 1	230.00	230.00	1S	0.12		1
3	Drew Switchyard	DW Gen 3	230.00	230.00	1S	1.39		1
4	Total 230kV Pole Line Miles					316.34	208.46	139
5	Encina		138.00	230.00	1S	0.05		2
6		Cannon	138.00	230.00	1S	0.08		2
7	Encina		138.00	138.00	1S	0.63		2
8			138.00	138.00	3	0.70		2
9			138.00	138.00	2W	19.58		1
10			138.00	138.00	4	0.60		1
11		Penasquitos	138.00	138.00	3	1.64		1
12	Palomar		138.00	138.00	1S	0.23		1
13			138.00	138.00	4	0.71		1
14		Batiquitos	138.00	138.00	1S		1.81	2
15	Encina		138.00	138.00	1S	0.02		1
16			138.00	138.00	1S		2.00	2
17			138.00	138.00	3		0.01	2
18		Palomar	138.00	138.00	1S		1.05	2
19	Telegraph Canyon	Proctor Valley	138.00	230.00	1S	2.60		2
20	Friars		138.00	138.00	4	0.16		1
21			138.00	230.00	1S	1.82		2
22		Doublet Tap	138.00	230.00	3		10.22	2
23	Doublet Tap	Doublet Substation	138.00	138.00	1S, 1W	1.81		2
24	Doublet Tap	Penasquitos	138.00	138.00	3		0.70	2
25	Chicarita		138.00	138.00	3,1S,1W		10.89	1
26			138.00	138.00	3, 1S		0.96	2
27		Shadowridge	138.00	138.00	1S		3.74	2
28			138.00	138.00	1W, 1S	0.41		1
29		NC Metering	138.00	138.00	1W	0.39		1
30	Main		138.00	138.00	3	0.21		1
31			138.00	138.00	3	6.43		1
32		South Bay	138.00	138.00	1W	0.08		1
33	Main	South Bay	138.00	138.00	3, 1W		6.90	3
34	South Bay		138.00	138.00	3		3.60	3
35			138.00	138.00	1W,1S		1.44	3
36					TOTAL	1,706.80	414.63	583

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	/ /	End of 2015/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1		Grant Hill	138.00	138.00	4	4.16		1
2	Capistrano		138.00	138.00	3, 1S, W	0.10	1.55	1
3		Pico	138.00	138.00	3, 1S		4.82	1
4	Santee		138.00	138.00	1W, 1S	2.35		1
5			138.00	138.00	1S	4.24		2
6			138.00	138.00	3, 1S	0.34		1
7		Los Coches	138.00	138.00	3	0.04		1
8	Sycamore		138.00	138.00	1W	5.71		1
9		Chicarita	138.00	138.00	4	0.06		1
10	Sycamore		138.00	138.00	1S		6.63	2
11		Santee	138.00	138.00	1W	1.56		1
12	Mission		138.00	138.00	2W		0.20	1
13			138.00	138.00	3, 1S		1.69	2
14		Carlton Hills Tap	138.00	138.00	3	1.69	8.00	2
15	Carlton Hills Tap	Carlton Hills	138.00	138.00	3, 1S		1.44	2
16	Telegraph Canyon		138.00	138.00	2S	6.66		2
17			138.00	138.00	3	0.08		1
18		South Bay	138.00	138.00	3		0.03	1
19	South Bay		138.00	138.00	3		3.75	2
20		Miguel 60 Tap	138.00	138.00	3		6.06	2
21	Miguel 60 Tap		138.00	138.00	3		0.69	2
22		Miguel	138.00	138.00	3		0.02	2
23	Miguel 60 Tap	Los Coches	138.00	138.00	3		15.38	2
24	North City Mtr Tap	Meadowlark Tap	138.00	138.00	3		7.40	2
25	Batiquitos	Meadowlark	138.00	138.00	1S	2.58		2
26	Chicarita	Meadowlark	138.00	138.00	2W	12.04		1
27	Shadowridge	Meadowlark Tap	138.00	138.00	3, 1W	3.99		2
28	Miguel		138.00	138.00	3	1.29		2
29		Proctor Valley	138.00	138.00	1W	0.05		1
30	Friars		138.00	138.00	4	0.10		
31		Mission	138.00	230.00	1S,3	1.22		2
32	Sycamore		138.00	138.00	1S	4.06	4.06	2
33			138.00	138.00	1S, 3	1.38		1
34		Carlton Hills	138.00	138.00	1S, 3	1.44	1.44	2
35	Margarita		138.00	138.00	3	1.22		2
36					TOTAL	1,706.80	414.63	583

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/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.
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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			138.00	230.00	1S	0.78		1
2		Trabuco	138.00	138.00	4	3.32		1
3	Talega	Rancho Mission Veijo	138.00	138.00	1S, 1W	7.74		1
4	Trabuco		138.00	138.00	1W	3.80		1
5			138.00	138.00	1S, 3		6.50	2
6			138.00	138.00	4	0.33		1
7		Pico	138.00	138.00	3	3.49		2
8	Trabuco		138.00	138.00	1W	3.70		1
9			138.00	138.00	1W	0.01		1
10		Capistrano	138.00	138.00	1W	0.02		1
11	San Mateo	San Mateo Tap	138.00	138.00	1W	0.66		1
12	San Mateo Tap	Z203020	138.00	138.00	3, 1W		7.08	2
13	Z203020	Z203021	138.00	138.00	4	0.33		1
14	Z203021	Z196606	138.00	138.00	1S	0.25		1
15	Z196606	Z248108	138.00	138.00	1W, 2W, 1S, 3	6.74		1
16	Z248108	Laguna Niguel	138.00	138.00	4	1.85		1
17	Talega Tap	Talega	138.00	138.00	1W	0.36		1
18	Pico		138.00	138.00	3, 1S		0.68	2
19		Talega	138.00	138.00	1W, S	0.11	0.41	1
20	Capistrano		138.00	138.00	1W	0.01		1
21			138.00	138.00	1W,1S	1.38		1
22		Laguna Niguel	138.00	138.00	4	1.82		
23	Rancho Mission Viejo	Margarita	138.00	138.00	1W, S	1.30		1
24	Mission		138.00	138.00	1S, W	2.94		2
25		Grant Hill	138.00	138.00	4	2.84		1
26	Encina	Encina Hub	138.00	138.00	1S	1.28	1.28	1
27	Encina Hub	Shadowridge	138.00	138.00	2W	6.72		1
28	East County	Boulevard East	138.00	138.00	1S	6.97		1
29	East County	Boulevard East	138.00	138.00	4	5.60		1
30	East County	Boulevard East	138.00	138.00	4	1.12		1
31	East County	Boulevard East	138.00	138.00	4	0.18		1
32	Pico		138.00	138.00	3,1s	0.90		2
33		Talega	138.00	138.00	1W	0.36		1
34			138.00	138.00	3		2.85	2
35		San Mateo	138.00	138.00	1W	0.60		1
36					TOTAL	1,706.80	414.63	583

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	/ /	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Encina		138.00	230.00	1S		0.05	2
2		Cannon	138.00	230.00	1S		0.08	2
3	Cannon	Encina Hub	138.00	138.00	1S		1.27	
4	138kV Dead					20.62		160
5	Total 138kV Length					182.64	126.68	310
6								
7	69kV Lines				1W	712.89	25.40	125
8					2W	7.11	1.38	
9					1S	37.12	1.50	
10					3	20.00	50.61	
11					4	62.10	0.60	
12	Total 69kV Pole Line Miles					839.22	79.49	125
13								
14								
15	EXPENSES, EXCEPT ISO							
16	Cost of Line							
17	ISO CHARGES							
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,706.80	414.63	583

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
2-2156 ACSR								5
3-1033.5 ACSR								6
2-2156 ACSR								7
3-1033.5 ACSR								8
2-1590 ACSR								9
								10
								11
1033.5 ACSR								12
1033.5 ACSR								13
1033.5 ACSR								14
1033.5 ACSR								15
2-1033.5 ACSR								16
1033.5 ACSR								17
1033.5 ACSR								18
2-1033.5 ACSR								19
2-1109 ACAR								20
1033.5 ACSR								21
1033.5 ACSR								22
1033.5 ACSR								23
1033.5 ACSR								24
2-1033.5 ACSR								25
1033.5 ACSR								26
2-1033.5 ACSR								27
2-1033.5 ACSR								28
1033.5 ACSR								29
1033.5 ACSR								30
1033.5 ACSR								31
2-1109 ACAR								32
2-1033.5 ACSR								33
2-1109 ACAR								34
2-1109 ACAR								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	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
2-900 ACSS								3
2-1109 ACAR								4
2-1109 ACAR								5
2-1109 ACAR								6
2-1109 ACAR								7
2-1109 ACAR								8
2-1033.5 ACSR								9
2-1109 ACAR								10
2-1033.5 ACSR								11
900 ACSS								12
605 ACSS								13
900 ACSS								14
605 ACSS								15
1113 ACSS								16
2-1033.5 ACSR								17
2-1109 ACAR								18
2-1033.5 ACSR								19
2-1033.5 ACSR								20
2-1109 ACAR								21
2-1109 ACAR								22
1109 ACAR								23
636 ACSS								24
605 ACSS								25
1033.5 ACSR								26
1109 ACAR								27
1109 ACAR								28
1-3500 KCMIL CU								29
1-2500 KCMIL CU								30
1-3500 KCMIL CU								31
1-2500 KCMIL CU								32
1-3500 KCMIL CU								33
1-3500 KCMIL CU								34
1-2500 KCMIL CU								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	36

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TRANSMISSION LINE STATISTICS (Continued)

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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.
1-3500 KCMIL CU								1
1-2500 KCMIL CU								2
1-3500 KCMIL CU								3
1033.5 ACSR								4
1033.5 ACSR								5
2-900 ACSS								6
2-1033.5 ACSR								7
2-900 ACSS								8
2-1033.5 ACSR								9
2-605 ACSR								10
2-1109 ACAR								11
2-900 ACSS								12
2-900 ACSS								13
2-3500 KCMIL CU								14
2-4000 KCMIL								15
2-3500 KCMIL CU								16
1-900 ACSS								17
2-3500 KCMIL CU								18
2-1033.5 ACSS/AW								19
2-1033.5 ACSS/TW								20
1033.5 ACSR								21
1033.5 ACSR								22
2-900 ACSS								23
2-1109 ACAR								24
2-1109 ACAR								25
2-1109 ACAR								26
2-1109 ACAR								27
2-1033.5 ACSR								28
2-1033.5 ACSR								29
1033.5 ACSR								30
1109 ACAR								31
1033.5 ACSR								32
900 ACSS								33
900 ACSS								34
900 ACSS								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	36

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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.
900 ACSS								1
636 ACSS								2
900 ACSS								3
								4
2-1033.5 ACSR								5
2-1109 ACAR								6
2-1109 ACAR								7
2-1109 ACAR								8
2-636 ACSR								9
1750 MCM AL								10
1033.5 ACSR								11
2-636 ACSR								12
1750 MCM AL								13
2-1109 ACAR								14
2-1033.5 ACSR								15
2-1109 ACAR								16
2-1109 ACAR								17
2-1109 ACAR								18
2-1109 ACAR								19
2-2500 KCMIL CU								20
400 MCM CU								21
636 ACSR/AW								22
336.4 ACSR/AW								23
636 ACSR/AW								24
636 ACSR								25
2-1033.5 ACSR								26
2-1033.5 ACSR								27
250MCM CU								28
336.4 ACSR								29
1-1033.5 ACSR								30
2-400 MCM CU								31
1-1033.5 ACSR								32
1-1033.5 ACSR								33
2-1033.5 ACSR								34
2-636 ACSR								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	36

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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.
2500 KCMIL CU								1
1033.5 ACSR								2
636 ACSR								3
1-1033.5 ACSR								4
605 ACSS								5
2-336.4 ACSR								6
1-750 MCM CU								7
636 ACSR								8
1750 KCMIL								9
900 ACSS/AW								10
636 ACSS								11
1-336.4 ACSR								12
2-336.4 ACSR								13
4-336.4 ACSR								14
900 ACSS/AW								15
1033.5 ACSR								16
1033.5 ACSR								17
1033.5 ACSR								18
2-400 MCM CU								19
2-636 ACSR								20
2-900 ACSS								21
2-636 ACSS								22
2-636 ACSS								23
636 ACSR								24
1033.5 ACSR								25
636 ACSR								26
250 MCM CU								27
250MCM CU								28
1033.5 ACSR								29
1-1750 KCMIL AL								30
1-900 ACSS/AW								31
1-900 ACSS/AW								32
4-336.4 ACSR								33
1-900 ACSS/AW								34
2-636 ACSR								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	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	/ /	End of 2015/Q4

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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1033.5 ACSR								1
1750 AL UG								2
1033.5 ACSR								3
1033.5 ACSR								4
1033.5 ACSR								5
1750 MCM CU								6
								7
394.5 5005								8
636 ACSR								9
336.4 ACSR								10
1033.5 ACSR/AW								11
336.4 ACSR/AW								12
1750 KCMIL AL								13
1033.5 ACSR/AW								14
336.4 ACSR/AW								15
1750 KCMIL AL								16
1033.5 ACSR/AW								17
900 ACSS								18
1033.5 ACSR								19
636 ACSR/AW								20
336.4 ACSR/AW								21
1750 KCMIL AL								22
1033.5 ACSR								23
2-636 ACSR								24
2500 MCM CU								25
2-1109 ACAR								26
900 ACSS								27
2-900 ACSS								28
2-2500 KCMIL CU								29
2-3000 KCMIL CU								30
2-5000 KCMIL CU								31
1033.5 ACSR								32
1033.5 ACSR								33
336.4 ACSR								34
1033.5 ACSR								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	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	/ /	End of 2015/Q4

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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-1033.5 ACSR								1
2-1109 ACAR								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
				9,443,853	19,310,883	1,616,947	30,371,683	15
	188,331,599	2,875,081,868	3,063,413,467					16
				6,339,817			6,339,817	17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	188,331,599	2,875,081,868	3,063,413,467	15,783,670	19,310,883	1,616,947	36,711,500	36

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: 422.6 Line No.: 16 Column: j

Costs available in total only.

Schedule Page: 422.6 Line No.: 16 Column: k

Costs available in total only.

Schedule Page: 422.6 Line No.: 16 Column: l

Costs available in total only.

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	/ /	End of 2015/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	Sycamore	Carlton Hills	4.06	1S	9.00	2	2
4							
5	UNDERGROUND						
6							
7	San Luis Rey	Melrose	3.13	4		1	1
8							
9	Melrose	Morro Hill	3.07	4		1	1
10							
11	Miramar	Scripps	0.46	4		1	1
12							
13	Paradise	Sunnyside	0.11	4		1	1
14	Paradise	Sunnyside	0.11	4		1	1
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
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38							
39							
40							
41							
42							
43							
44	TOTAL		10.94		9.00	7	7

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/AW	9	138	2,528,086	11,452,708	7,196,768		21,177,562	3
									4
									5
									6
3000	KCMILCU	8"	69			15,405,343		15,405,343	7
									8
3000	KCMILCU	8"	69			14,801,212		14,801,212	9
									10
1750	KCMILAL	8"	69			2,342,111		2,342,111	11
									12
1750	KCMILAL	8"	69			187,218		187,218	13
1750	KCMILAL	8"	69						14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
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									35
									36
									37
									38
									39
									40
									41
									42
									43
				2,528,086	11,452,708	39,932,652		53,913,446	44

Schedule Page: 424 Line No.: 3 Column: c
To report addition of 4.06 miles for TL13828 from Sycamore to Carlton Hills for 2015.

Schedule Page: 424 Line No.: 7 Column: c
To report addition of 3.13 miles for TL6966 from San Luis Rey to Melrose for 2015.

Schedule Page: 424 Line No.: 9 Column: c
To report addition of 3.07 miles for TL694 from Melrose to Morro Hill for 2015.

Schedule Page: 424 Line No.: 11 Column: c
To report addition of 0.46 miles for TL669 from Miramar to Scripps for 2015.

Schedule Page: 424 Line No.: 13 Column: c
To report addition of 0.11 miles for TL628 from Paradise to Sunnyside for 2015.

Schedule Page: 424 Line No.: 14 Column: c
To report addition of 0.11 miles for TL6970 from Paradise to Sunnyside for 2015.

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	/ /	End of 2015/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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ALPINE, Alpine	Dist. Unattended	69.00	12.00	
2	AMHERST, San Diego	Dist. Unattended	12.00	4.00	
3	ARTESIAN, San Diego	Dist. Unattended	69.00	12.00	
4	ASH, Escondido	Dist. Unattended	69.00	12.00	
5	AVOCADO, Fallbrook	Dist. Unattended	69.00	12.00	
6	B, San Diego	Dist. Unattended	69.00	12.00	
7	BARRETT, Barrett	Dist. Unattended	69.00	12.00	
8	BASILONE, San Clemente	Dist. Unattended	69.00	12.00	
9	BATIQUITOS, Encinitas	Dist. Unattended	138.00	12.00	
10	BERNARDO, Rancho Bernardo	Dist. Unattended	69.00	12.00	
11	BORDER, San Diego	Dist. Unattended	69.00	12.00	
12	BORREGO, Borrego Springs	Dist. Unattended	69.00	12.00	
13	BOSTONIA, El Cajon	Dist. Unattended	12.00	4.00	
14	BOULDER CREEK, Santa Ysabel	Dist. Unattended	69.00	12.00	
15	BOULEVARD EAST, Boulevard	Dist. Unattended	138.00	12.00	
16	CABRILLO, San Diego	Dist. Unattended	69.00	12.00	
17	CALAVO GARDENS, El Cajon	Dist. Unattended	12.00	4.00	
18	CAMERON, Campo	Dist. Unattended	69.00	12.00	
19	CANNON, Carlsbad	Dist. Unattended	138.00	12.00	
20	CAPISTRANO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
21	CARLTON HILLS, Santee	Dist. Unattended	138.00	12.00	
22	CENTRAL, San Diego	Dist. Unattended	12.00	4.00	
23	CHICARITA, San Diego	Dist. Unattended	138.00	12.00	
24	CHOLLAS, Lemon Grove	Dist. Unattended	69.00	12.00	
25	CHULA VISTA, San Diego	Dist. Unattended	12.00	4.00	
26	CLAIREMONT, San Diego	Dist. Unattended	69.00	12.00	
27	CORONADO, Coronado	Dist. Unattended	69.00	12.00	
28	CREELMAN, Ramona	Dist. Unattended	69.00	12.00	
29	CRESTWOOD, Campo	Dist. Unattended	69.00	12.00	
30	CRISTIANITOS, Mission Viejo	Dist. Unattended	69.00	12.00	
31	DEL MAR, Del Mar	Dist. Unattended	69.00	12.00	
32	DESCANSO, Descanso	Dist. Unattended	69.00	12.00	
33	DIVISION, San Diego	Dist. Unattended	69.00	12.00	
34	DUNHILL, San Diego	Dist. Unattended	69.00	4.00	
35	EAST OCEANSIDE, Oceanside	Dist. Unattended	12.00	4.00	
36	EASTGATE, San Diego	Dist. Unattended	69.00	12.00	
37	EL CAJON, El Cajon	Dist. Unattended	69.00	12.00	
38	ELLIOTT, San Diego	Dist. Unattended	69.00	12.00	
39	ENCANTO, San Diego	Dist. Unattended	12.00	4.00	
40	ENCINITAS, Encinitas	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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ENCINITAS, Encinitas	Dist. Unattended	12.00	4.00	
2	ESCO, Escondido	Dist. Unattended	69.00	12.00	
3	ESCO, Escondido	Dist. Unattended	12.00	4.00	
4	ESCONDIDO, Escondido	Dist. Unattended	69.00	12.00	
5	F, San Diego	Dist. Unattended	69.00	12.00	
6	FELICITA, Escondido	Dist. Unattended	69.00	12.00	
7	FENTON, San Diego	Dist. Unattended	69.00	12.00	
8	FRIARS, San Diego	Dist. Unattended	138.00	12.00	
9	GARFIELD, El Cajon	Dist. Unattended	69.00	12.00	
10	GENESEE, San Diego	Dist. Unattended	69.00	12.00	
11	GLENCLIFF-GC	Dist. Unattended	69.00	12.00	
12	GRANITE, El Cajon	Dist. Unattended	69.00	12.00	
13	GRANT HILL, San Diego	Dist. Unattended	138.00	12.00	
14	HILLTOP, San Diego	Dist. Unattended	12.00	4.00	
15	IMPERIAL BEACH, Imperial Beach	Dist. Unattended	69.00	12.00	
16	IMPERIAL BEACH, Imperial Beach	Dist. Unattended	12.00	4.00	
17	JAMACHA, Jamacha	Dist. Unattended	69.00	12.00	
18	JAPANESE MESA, San Clemente	Dist. Unattended	69.00	12.00	
19	KEARNY, San Diego	Dist. Unattended	69.00	12.00	
20	KETTNER, San Diego	Dist. Unattended	69.00	12.00	
21	KYOCERA, San Diego	Dist. Unattended	69.00	12.00	
22	LA JOLLA, La Jolla	Dist. Unattended	69.00	12.00	
23	LAGUNA NIGUEL, Laguna Niguel	Dist. Unattended	138.00	12.00	
24	LAS PULGAS, Oceanside	Dist. Unattended	69.00	12.00	
25	LILAC, Valley Center	Dist. Unattended	69.00	12.00	
26	LINCOLN ACRES, National City	Dist. Unattended	12.00	4.00	
27	LOS COCHES, Lakeside	Dist. Unattended	69.00	12.00	
28	LOVELAND, Alpine	Dist. Unattended	69.00	12.00	
29	MARGARITA, Mission Viejo	Dist. Unattended	138.00	12.00	
30	MELROSE, Vista	Dist. Unattended	69.00	12.00	
31	MESA HEIGHTS, San Diego	Dist. Unattended	69.00	12.00	
32	MESA RIM, San Diego	Dist. Unattended	69.00	12.00	
33	MIRAMAR, San Diego	Dist. Unattended	69.00	12.00	
34	MIRA SORRENTO, San Diego	Dist. Unattended	69.00	12.00	
35	MISSION, San Diego	Dist. Unattended	69.00	12.00	
36	MONSERATE, Fallbrook	Dist. Unattended	69.00	12.00	
37	MONTGOMERY, Chula Vista	Dist. Unattended	69.00	12.00	
38	MORRO HILL, Oceanside	Dist. Unattended	69.00	12.00	
39	MURRAY, La Mesa	Dist. Unattended	69.00	12.00	
40	NATIONAL CITY, National City	Dist. Unattended	69.00	4.00	12.00

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	/ /	End of 2015/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 (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NAVAL STATION Switchyard, San Diego-NSM	Dist. Unattended	69.00		
2	NORTH CITY WEST, San Diego	Dist. Unattended	69.00	12.00	
3	NORTH VISTA,Vista	Dist. Unattended	12.00	4.00	
4	OCEANSIDE, Oceanside	Dist. Unattended	69.00	12.00	
5	OLD TOWN, San Diego	Dist. Unattended	69.00	12.00	
6	OLIVENHAIN, Escondido	Dist. Unattended	69.00	12.00	
7	OTAY LAKES, Chula Vista	Dist. Unattended	69.00	12.00	
8	OTAY, Chula Vista	Dist. Unattended	69.00	12.00	
9	PACIFIC BEACH, San Diego	Dist. Unattended	69.00	12.00	
10	PALA, San Diego County	Dist. Unattended	69.00	12.00	
11	PALOMAR AIRPORT, Carlsbad	Dist. Unattended	138.00	12.00	
12	PARADISE, San Diego	Dist. Unattended	69.00	12.00	
13	PENDLETON, Oceanside	Dist. Unattended	69.00	12.00	
14	PICO, San Clemente	Dist. Unattended	138.00	12.00	
15	POINT LOMA SEWAGE, San Diego	Dist. Unattended	12.00	4.00	
16	POINT LOMA, San Diego	Dist. Unattended	69.00	12.00	
17	POMERADO, San Diego	Dist. Unattended	69.00	12.00	
18	POWAY, Poway	Dist. Unattended	69.00	12.00	
19	PROCTOR VALLEY, Bonita	Dist. Unattended	138.00	12.00	
20	RAMONA, Ramona	Dist. Unattended	12.00	4.00	
21	RANCHO CARMEL, San Diego	Dist. Unattended	69.00	12.00	
22	RANCHO MISSION VIEJO, Rancho Mission Viejo	Dist. Unattended	138.00	12.00	
23	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	12.00	
24	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	4.00	
25	RINCON, Rincon	Dist. Unattended	69.00	12.00	
26	ROLANDO, San Diego	Dist. Unattended	12.00	4.00	
27	ROSE CANYON, San Diego	Dist. Unattended	69.00	12.00	
28	ROSEVILLE, San Diego	Dist. Unattended	12.00	4.00	
29	SAMPSON, San Diego	Dist. Unattended	69.00	12.00	
30	SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
31	SAN LUIS REY, Oceanside	Dist. Unattended	69.00	12.00	
32	SAN MARCOS, San Marcos	Dist. Unattended	69.00	12.00	
33	SAN MATEO, San Clemente	Dist. Unattended	138.00	12.00	
34	SAN YSIDRO, San Ysidro	Dist. Unattended	69.00	12.00	
35	SANTA YSABEL, Santa Ysabel	Dist. Unattended	69.00	12.00	
36	SANTEE, Santee	Dist. Unattended	138.00	12.00	
37	SCRIPPS, San Diego	Dist. Unattended	69.00	12.00	
38	SEWAGE PUMP STA (3), San Diego	Dist. Unattended	12.00	4.00	
39	SHADOWRIDGE, Vista	Dist. Unattended	138.00	12.00	
40	SHORECLIFFS, San Clemente	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	/ /	End of 2015/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	SOUTH SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
2	SPRING VALLEY, Spring Valley	Dist. Unattended	69.00	12.00	
3	STREAMVIEW, San Diego	Dist. Unattended	69.00	12.00	
4	STUART, Oceanside	Dist. Unattended	69.00	12.00	
5	SUNNYSIDE, San Diego	Dist. Unattended	69.00	12.00	
6	SWEETWATER, National City	Dist. Unattended	69.00	12.00	
7	TELEGRAPH CANYON, Chula Vista	Dist. Unattended	138.00	12.00	
8	TORREY PINES, San Diego	Dist. Unattended	69.00	12.00	
9	TRABUCO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
10	UCM Switchyard, San Diego	Dist. Unattended	69.00		
11	URBAN, San Diego	Dist. Unattended	69.00	12.00	
12	VALLEY CENTER, Valley Center	Dist. Unattended	69.00	12.00	
13	VISTA, Vista	Dist. Unattended	12.00	4.00	
14	WARNERS, Warner Springs	Dist. Unattended	69.00	12.00	
15	WARREN CANYON, Poway	Dist. Unattended	69.00	12.00	
16	WARREN CANYON, Poway	Dist. Unattended	69.00	4.00	
17	WITHERBY, San Diego	Dist. Unattended	12.00	4.00	
18	DOUBLETT Switchyard, San Diego	Trans. Unattended	138.00	69.00	
19	EAST COUNTY, Boulevard	Trans. Unattended	500.00	230.00	12.00
20	EAST COUNTY, Boulevard	Trans. Unattended	230.00	138.00	
21	ENCINA Switchyard, Carlsbad	Trans. Unattended	138.00		
22	ENCINA, Carlsbad	Trans. Unattended	230.00	138.00	
23	ESCONDIDO, Escondido	Trans. Unattended	230.00	69.00	
24	GOAL LINE, Escondido	Trans. Unattended	69.00		
25	IMPERIAL VALLEY, El Centro	Trans. Unattended	500.00	230.00	12.00
26	LOS COCHES, Lakeside	Trans. Unattended	138.00	69.00	
27	MIGUEL, Bonita	Trans. Unattended	230.00	69.00	
28	MIGUEL, Bonita	Trans. Unattended	230.00	138.00	
29	MIGUEL, Bonita	Trans. Unattended	500.00	230.00	12.00
30	MIRAMAR GT, San Diego	Trans. Unattended	12.00	69.00	
31	MISSION, San Diego	Trans. Unattended	138.00	69.00	
32	MISSION, San Diego	Trans. Unattended	230.00	69.00	
33	MISSION, San Diego	Trans. Unattended	230.00	138.00	
34	NARROWS, Borrego Springs	Trans. Unattended	88.00	69.00	12.00
35	OCOTILLO Switchyard, Ocotillo	Trans. Unattended	500.00		
36	OLD TOWN, San Diego	Trans. Unattended	230.00	69.00	
37	OTAY MESA Switchyard, Chula Vista	Trans. Unattended	230.00		
38	PENASQUITOS, San Diego	Trans. Unattended	138.00	69.00	
39	PENASQUITOS, San Diego	Trans. Unattended	230.00	138.00	
40	PENASQUITOS, San Diego	Trans. Unattended	230.00	69.00	

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	/ /	End of 2015/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 (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	SILVERGATE, San Diego	Trans. Unattended	230.00	69.00	
3	SOUTH BAY, Chula Vista	Trans. Unattended	138.00	69.00	
4	SUNCREST, Japatul	Trans. Unattended	500.00	230.00	12.00
5	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	69.00	
6	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	138.00	
7	TALEGA, San Clemente	Trans. Unattended	138.00	69.00	
8	TALEGA, San Clemente	Trans. Unattended	230.00	138.00	
9	WABASH Switchyard, San Diego	Trans. Unattended	69.00		
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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	/ /	End of 2015/Q4

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
6	1					2
56	2					3
84	3	1				4
41	2					5
112	4					6
13	1					7
28	1					8
56	2	1				9
140	5					10
56	2					11
26	2					12
10	1					13
2	1					14
28	1					15
56	2					16
7	2					17
6	1					18
112	4					19
56	2					20
56	2					21
6	1					22
84	3					23
56	2	1				24
6	2					25
56	2					26
56	2					27
84	3					28
13	1					29
8	1					30
84	3					31
7	1					32
53	2					33
8	1					34
6	1					35
56	2					36
112	4					37
84	3					38
1	4					39
56	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)	
6	1					1
56	2					2
4	1					3
84	3	1				4
84	3					5
84	3					6
8	1					7
56	2					8
28	1					9
112	4					10
7	1					11
112	4					12
56	2					13
3	1					14
56	2					15
6	1					16
84	3					17
14	2					18
84	3					19
56	2					20
9	1					21
56	2					22
112	4					23
28	1					24
56	2					25
6	1					26
84	3					27
28	1					28
112	4					29
112	4					30
84	3					31
112	4					32
84	3					33
56	2					34
112	4					35
56	2					36
56	2					37
13	1					38
112	4	1				39
14	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) (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.
						1
56	2					2
3	1					3
56	2					4
84	3					5
28	1					6
5	1					7
56	2	1				8
56	2					9
28	1					10
84	3					11
56	2					12
56	2					13
56	2					14
6	1					15
84	2					16
84	3					17
56	2					18
56	2	1				19
6	1					20
84	3					21
56	2					22
41	2					23
6	1					24
25	2					25
13	2					26
56	2					27
6	1					28
112	4					29
3	1					30
112	4					31
112	4					32
45	2					33
56	2					34
12	1					35
56	2					36
84	3					37
30	6	3				38
84	3					39
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)	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)	
3	1					1
56	2					2
56	2					3
8	1					4
28	1					5
56	2					6
112	4					7
112	4					8
112	4					9
						10
84	3					11
28	1					12
10	2					13
28	1					14
8	1					15
7	1					16
6	1					17
						18
1120	1					19
392	1					20
						21
784	2					22
672	3					23
						24
2840	9	2				25
448	2					26
448	2					27
784	2					28
2240	6	1				29
50	1					30
499	5					31
224	1					32
784	2					33
10	3					34
						35
448	2					36
						37
520	3					38
392	1	1				39
448	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) (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.
672	3					1
448	2	1				2
224	1					3
2240	6	1				4
672	3	1				5
392	1	1				6
140	1	1				7
1102	4					8
						9
						10
						11
						12
						13
						14
						15
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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	/ /	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Construction Work in Progress	Sempra Energy	107	14,192,382
3	Other Utility Plant	Sempra Energy	118	4,067,123
4	Cash	Sempra Energy	131	-152,882
5	Other Accounts Receivable	Sempra Energy	143	408,352
6	Accounts Receivable from Associated Companies	Sempra Energy	146	663,537
7	Stores Expense Undistributed	Sempra Energy	163	-25,223
8	Prepayments	Sempra Energy	165	85,080,077
9	Preliminary Survey & Investigation Charges	Sempra Energy	183	133,174
10	Clearing Accounts	Sempra Energy	184	2,234,040
11	Research, Development, & Demonstration Expenditure	Sempra Energy	188	-12,611
12	Accumulated Other Comprehensive Income	Sempra Energy	219	3,208,104
13	Accumulated Provisions for Pensions and Benefits	Sempra Energy	228.3	-16,381,494
14	Accounts Payable	Sempra Energy	232	-1,019,424
15	Miscellaneous Current & Accrued Liabilities	Sempra Energy	242	-4,623,990
16	Other Deferred Credits	Sempra Energy	253	-8,757,607
17	Expend. for Civic & Political Activities	Sempra Energy	426.4	418,122
18	Other Electric Revenues	Sempra Energy	456	-3,185
19	Operation Supervision and Engineering	Sempra Energy	500	-1,846
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Sempra Energy	146	803,711
22	Depreciation Expense	Sempra Energy	146	803,380
23	Environmental Services	Sempra Energy	146	60,896
24	External Affairs	Sempra Energy	146	281,001
25	Fleet Services	Sempra Energy	146	21,592
26	Human Resources	Sempra Energy	146	17,792,467
27	Information Technology	Sempra Energy	146	4,989,247
28	Real Estate & Facilities	Sempra Energy	146	13,906,373
29	Supply Management	Sempra Energy	146	1,274,412
30	Depreciation Expense	U.S. Gas & Power Natural Gas	146	46,630
31	Environmental Services	U.S. Gas & Power Natural Gas	146	609
32	External Affairs	U.S. Gas & Power Natural Gas	146	38,100
33	Human Resources	U.S. Gas & Power Natural Gas	146	123,366
34	Information Technology	U.S. Gas & Power Natural Gas	146	195,583
35	Real Estate & Facilities	U.S. Gas & Power Natural Gas	146	134,607
36	Supply Management	U.S. Gas & Power Natural Gas	146	174,939
37	Depreciation Expense	U.S. Gas & Power Natural Gas	146	18,192
38	Environmental Services	U.S. Gas & Power Natural Gas	146	284
39	Human Resources	U.S. Gas & Power Natural Gas	146	109,093
40	Information Technology	U.S. Gas & Power Natural Gas	146	132,415
41	Real Estate & Facilities	U.S. Gas & Power Natural Gas	146	62,225
42	Supply Management	U.S. Gas & Power Natural Gas	146	12,861
1	**Non-power Goods or Services Provided by Affiliated**			
2	Miscellaneous Steam Power Expenses	Sempra Energy	506	515,100

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Operation Supervision & Engineering	Sempra Energy	546	405,248
4	Miscellaneous Other Power Generation Expenses	Sempra Energy	549	-1,816
5	Maint. of Misc. Other Power Gen. Plant- Major Only	Sempra Energy	554	-973
6	System Control & Load Dispatching (Major Only)	Sempra Energy	556	-837
7	Other Expenses	Sempra Energy	557	-5,015
8	Operation Supervision & Engineering	Sempra Energy	560	-12,042
9	Load Dispatch	Sempra Energy	561	-1,625
10	Miscellaneous Transmission Expenses	Sempra Energy	566	190,832
11	Maintenance of Structures	Sempra Energy	569	-10,440
12	Maintenance of Station Equipment (Major Only)	Sempra Energy	570	-173
13	Maintenance of Overhead Lines (Major Only)	Sempra Energy	571	-1,853
14	Operation & Engineering Supervision	Sempra Energy	580	-107,977
15	Load Dispatching (Major Only)	Sempra Energy	581	-3,208
16	Meter Expenses	Sempra Energy	586	-11,017
17	Customer Installation Expenses	Sempra Energy	587	-129
18	Miscellaneous Distribution Expenses	Sempra Energy	588	293,795
19	Rents	Sempra Energy	589	-113
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Southern California Gas Company	146	6,604,088
22	Business Planning/Bus. Solutions	Southern California Gas Company	146	367
23	Customer Services	Southern California Gas Company	146	1,158,473
24	Depreciation Expense	Southern California Gas Company	146	8,080,287
25	Engineering / Const. Services	Southern California Gas Company	146	673,178
26	Environmental Services	Southern California Gas Company	146	267,353
27	External Affairs	Southern California Gas Company	146	1,105,618
28	Fleet Services	Southern California Gas Company	146	3,187,481
29	Human Resources	Southern California Gas Company	146	-1,052,663
30	Information Technology	Southern California Gas Company	146	95,326,706
31	Real Estate & Facilities	Southern California Gas Company	146	494,108
32	Supply Management	Southern California Gas Company	146	673,945
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Maintenance Supervision & Engineering (Major Only)	Sempra Energy	590	-2,705
3	Maintenance of Energy Storage Equipment	Sempra Energy	592	-347
4	Maintenance of Overhead Lines	Sempra Energy	593	-19,082

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	Maintenance of Meters	Sempra Energy	597	-309
6	Maintenance of Miscellaneous Distribution Plant	Sempra Energy	598	-154
7	Operation Supervision and Engineering	Sempra Energy	850	-2,166
8	Compressor Station Labor and Expenses	Sempra Energy	853	-827
9	Mains Expenses	Sempra Energy	856	-1,059
10	Maintenance of Mains	Sempra Energy	863	-1,417
11	Maint. of Measuring & Regulating Station Equipment	Sempra Energy	865	-422
12	Operation Supervision & Engineering	Sempra Energy	870	-24,768
13	Mains and Services Expenses	Sempra Energy	874	-8,868
14	Measuring and Regulating Station Exp- General	Sempra Energy	875	-535
15	Customer Insallations Expenses	Sempra Energy	879	-32,625
16	Distribution Other Expenses	Sempra Energy	880	-20,076
17	Maintenance of Mains	Sempra Energy	887	-3,043
18	Meter Reading Expenses	Sempra Energy	902	-13,617
19	Customer Records and Collection Expenses	Sempra Energy	903	-40,155
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Cutomer Assistance Expenses	Sempra Energy	908	-65,712
3	Miscellaneous Customer Service and Info Expenses	Sempra Energy	910	242,208
4	Administrative and General Salaries	Sempra Energy	920	2,735,946
5	Office Supplies and Expenses	Sempra Energy	921	-825,526
6	Outside Services Employed	Sempra Energy	923	73,219,910

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	/ /	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7	Property Insurance	Sempra Energy	924	215,668
8	Injuries and Damages	Sempra Energy	925	10,101,973
9	Employee Pension and Benefits	Sempra Energy	926	3,754,913
10	Regulatory Commission Expenses	Sempra Energy	928	1,932,276
11	Miscellaneous General Expense	Sempra Energy	930.2	82,658
12	Rents	Sempra Energy	931	-61,754
13	Maintenance of General Plant	Sempra Energy	935	-14,571
14	Purchased Power	Energia Sierra Juarez	555	21,444,106
15	Construction Work in Progress	Southern California Gas Company	107	13,554,665
16	Other Utility Plant	Southern California Gas Company	118	2,902,152
17	Clearing Accounts	Southern California Gas Company	184	2,171,536
18	Miscellaneous Deferred Debits	Southern California Gas Company	186	10,675
19	Accounts Payable	Southern California Gas Company	232	61,315
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Miscellaneous Steam Power Expenses	Southern California Gas Company	506	14,281
3	Miscellaneous Transmission Expenses	Southern California Gas Company	566	201,676
4	Miscellaneous Distribution Expenses	Southern California Gas Company	588	17,945
5	Operation Supervision & Engineering	Southern California Gas Company	850	2,006,692
6	System Control & Load Dispatching	Southern California Gas Company	851	663,546
7	Compressor Station Labor and Expenses	Southern California Gas Company	853	37,951
8	Other Expenses	Southern California Gas Company	859	47,392

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
9	Maintenance Supervision and Engineering	Southern California Gas Company	861	17,172
10	Maintenance of Mains	Southern California Gas Company	863	136,686
11	Maintenance of Communication Equipment	Southern California Gas Company	866	-639
12	Maintenance of other Equipment	Southern California Gas Company	867	-90
13	Gas Trans Maintenance Operation Super& Engineering	Southern California Gas Company	870	3,223,246
14	TIMP-MAINS & SVCS EX	Southern California Gas Company	874	2,407
15	Meter and Hour Regulator Expenses	Southern California Gas Company	878	667
16	Distribution Other Expenses	Southern California Gas Company	880	159,878
17	Maintenance of Mains	Southern California Gas Company	887	249,575
18	Maint. of Measuring & Regulating Stat. Equip- Gen	Southern California Gas Company	889	-287
19	Maintenance of Meters and House Regulators	Southern California Gas Company	893	156,868
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Meter Reading Expenses	Southern California Gas Company	902	74,077
3	Customer Records and Collection Expenses	Southern California Gas Company	903	2,581,885
4	Supervison	Southern California Gas Company	907	30,477
5	Customer Assistance Expenses	Southern California Gas Company	908	322,533
6	Misc. Customer Service and Information Expenses	Southern California Gas Company	910	204,135
7	Outside Services Employed	Southern California Gas Company	923	60,655,421
8	Injuries and Damages	Southern California Gas Company	925	325,163
9	Employee Pension and Benefits	Southern California Gas Company	926	72,943
10	Regulatory Commission Expenses	Southern California Gas Company	928	1,838,966

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	/ /	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
11	Rents	Southern California Gas Company	931	944,144
12	Miscellaneous General Expeneses	Southern California Gas Company	930.2	145,087
13	Maintenance of General Plant	Southern California Gas Company	935	664,139
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20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 Column: a

Per the FERC Audit, Docket No. FA12-8-000, the following disclosure is required: There has been a lack of reporting cost allocation methods since the issuance of Order No. 715 on page 429 relating to the footnote only.

This issue has no financial impact on our financial statements.

San Diego Gas and Electric previously provided footnotes on FERC Page 429 per Order No. 715. However, based on FERC audit findings and detailed information now provided, footnotes in years prior to 2013 were not fully descriptive for cost allocation methods of affiliate support to San Diego Gas and Electric, and San Diego Gas and Electric support to affiliates. In 2013, complete and detailed cost allocation methodology footnotes were provided and will continue to be described in such manner each year.

All non-power goods and services provided by affiliated companies are billed to San Diego Gas and Electric at fully loaded cost.

Schedule Page: 429 Line No.: 2 Column: b

Fully loaded costs include all direct expenses, indirect overheads and shared service billing. Shared service non-power goods and service support cost are based on allocation process methodologies for Sempra Energy Corporate Center cost centers. The following information regarding multi-factor and causal-beneficial relationship information was provided by the Sempra Energy Corporate Center Budget and Reporting Manager, and is a summary of the varying methodologies used: Multi-factor basic, also known as "Four-Factor", this method is used by a department for which there is no causal relationship. The Multi-factor basic weights four factors equally for each business unit: Revenues, Operating Expenses, Gross Plant and Investment, and Employees; Multi-factor split, this method divides costs 50% to Utilities, 50% to Global. The Multi-factor (basic) percentages are the basis for the allocation between Southern California Gas Company and San Diego Gas and Electric, and between Global Business Units; Multi-factor Utility, this method uses the same four factors that appear in Multi-factor (basic), but calculates ratios for California utility business units only; Shared asset allocation of depreciation expense associated with capitalized assets at each shared service entity are allocated uniquely depending on its allocation of benefit or supporting purpose; Causal – Headquarters Occupancy, rent, depreciation & ROR related to new headquarters this is allocated based on the square footage directly occupied by the business units. Sempra Energy Corporate Center's direct occupation, except for an executive portion which is retained, is reallocated based on the Multi-Factor Basic. Average – CFO, this method is a weighted average of annual labor budget for departments that report to the CFO; Average – Controller, this method is a weighted average of annual labor budget for departments that report to the Controller; Average – Senior Vice President Human Resources, this method is a weighted average of annual labor budget for departments that report to the Senior Vice President of Human Resources; Average – Senior Vice President of Treasury, this method is a weighted average of annual labor budget for departments that report to the Senior Vice President of Treasury; Average – Vice President External Affairs, this method is a weighted average of annual labor budget for departments that report to the Vice President of External Affairs; Causal – Audit US, this method is based on audit hours planned for each business unit in the coming year. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Corporate Responsibility, this method uses the Multi-factor (basic) allocation as a starting point, and then reduces the percentages to exclude a portion attributed to managing costs which are Retained; Causal CCURE System, this allocation is a weighted average of the number of card readers used per business unit for depreciation of the CCURE 9000 Security System. Sempra Energy Corporate Center units are reallocated using Multi-factor Basic, resulting in a blended percentage; Causal – Executive Benefits (Southern California Gas Company), direct restricted stock and stock options expense for Southern California Gas Company executives is allocated because some executives are shared by more than one business unit. The percentages reflect a weighted average of each executive's work distribution among business units; Causal – Executive Benefits (San Diego Gas and Electric), direct restricted stock and stock options expense for San Diego Gas and Electric executives is allocated because some executives are shared by more than one business unit. The percentages reflect a weighted average of each executive's work distribution among business units; Causal – Executive Full Time Employee Equivalents, this method allocated the support and administration cost for executive related services using a weighted average of participating officers. Executives are heavily weighted (75%) compared to Directors and Vice Presidents (25%). The Sempra Energy Corporate Center shared service Executives are then Multi-factored (basic) resulting in a blended percentage for each business unit; Causal – Executive Security, this method accounts for the transportation services available to Sempra Energy Corporate Center officers and considers their allocation methods in general. The CEO (retained) has one dedicated driver, while the other 3 drivers are available to other executives and assumes an even allocation of Utility, Global and additional Retained. The result is 25% Utility, 25% Global and 50% Retained for 4 drivers; Causal – Finance, for the Project Finance department, the Director estimates percentages of effort for the business units based on significant projects to be financed in the upcoming period; Causal – Fire Insurance, this method allocates all costs for Fire Insurance based on miles of electrical lines in wildland areas per business unit; Causal – FLP (Financial Leadership Program), this allocation is a weighted average of the employees in the Financial Leadership Program based on the business units they support. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Full Time Employee Equivalents, total Full Time Employee equivalents (FTE’s) are used as the basis for allocation of most Human Resource departmental services provided on behalf of all the business units. The Sempra Energy Corporate Center FTE’s are re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Global Risk, Energy Risk Management estimates the percentage of hours worked on both market risk (energy risk and Dodd Frank) and the credit risk by business unit; Causal – Group Executive Insurance, this method allocates the group executive insurance policy using a weighted average of covered officers, per their assigned business unit. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Headquarter Security, this method allocates the costs of Sempra Energy Corporate Center security, excluding the Headquarter guard service contract, by the Causal - Full Time Employee Equivalent method, and allocates the Headquarter guard service contract by the ratio of employees occupying the Sempra Energy Corporate Center Headquarter building; Causal – Hyperion Financial Management and Consolidation System, this allocation is a weighted average of the headcount of Hyperion Financial Management and Consolidation System users. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Major Projects & Controls, the Major Projects and Controls group allocates its overall costs based on a percentage of direct labor charges for each month; and overall average is estimated for the Plan years. Causal – MyInfo Services Contract, MyInfo services cost is allocated by the number of people in the MyInfo system. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Pension, this method allocates based on the relative value of Sempra’s three major pension funds: San Diego Gas & Electric, Southern California Gas, and Sempra Energy Corporate/Global. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal – Tax Services, this allocation is a weighted average of the workload of each employee within the Tax department based on an annual time study. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; and, Causal – Treasury, for the Finance department, the Assistant Treasurer estimates percentages of effort for the business units based on significant projects requiring financing or advisory work.

Schedule Page: 429 Line No.: 21 Column: a

All non-power goods and services provided by San Diego Gas and Electric are billed at fully loaded cost.

Affiliate companies charged by San Diego Gas and Electric for less than $250,000 include: Sempra International, South America.

Fully loaded costs include all direct expenses, indirect overheads and, where applicable, a labor premium required by the Enova/Pacific Enterprises Merger Decision (D.98-03-073) for shared service billing. The Merger Decision also requires San Diego Gas and Electric to charge employee transfer fees to an affiliated company. Shared service non-power goods and service support cost are based on allocation process methodologies for 118 San Diego Gas and Electric cost centers. The following causal-beneficial relationship information is a summary of the 20 varying methodologies used: 39 cost centers used a form of LAN ID counts to determine the shared allocation; 18 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 11 cost centers used a form of prior year project assignments as a base for the current year distribution, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 9 cost centers used a form of an allocation of space study identifying building square footage assigned; 8 cost centers used a current year study of budgeted activities by Affiliate; 7 cost centers used a form of the current year budgeted activities and/or dollars study, which is adjusted as necessary when there are changes that impact the current allocation; 4 cost centers used a form of Full Time Employee equivalent statistics for support; 4 cost centers used a form of assigning 100% of costs to Southern California Gas Company in support of business case decisions approved for Southern California Gas Company’s sole benefit; 4 cost centers used an allocation of application software login activity and statistics for active accounts; 3 cost centers used the existing current year Sempra Energy Corporate Center four factor multi-factor allocation which includes weighted averages of operating revenue, operating expenses, gross plant and investment and Full Time Employee equivalent numbers; 2 cost centers used a form of an allocation of computer and/or server system and resource usage statistics; there was one use by a cost center of each of the remaining allocation methodologies: a ratio of miles of pipe installed existing and/or current year by service territory allocations; an allocation of time by Director’s assessment of planned current year project assignments within the cost center, which is adjusted as necessary when current year projects begin or change and impact the current allocation; assigning 100% of costs to Sempra Energy Corporate Center for facilities maintenance support of Sempra Energy Corporate Center buildings and other facilities; an allocation using a study of the annual Capital dollars spent for SDG&E Sempra Energy Corporation Center; electric and gas meter counts and service territory allocations; a weighted average allocation of Sempra Energy Utility (including both Southern California Gas Company and San Diego Gas and Electric) gas revenue; a study of the existing current billing cycle support covering the computer resource maintenance contract agreement(s); and, a study based on the amount charges to direct billing orders; a Workload Distribution Study.

Schedule Page: 429.1   Line No.: 21   Column: a

Fully loaded costs include all direct expenses, indirect overheads and shared service billing. Shared service non-power goods and service support cost are based on allocation process methodologies for 109
Southern California Gas Company cost centers. The following causal-beneficial relationship information is a summary of the 26 varying methodologies used: 44 cost centers used a form of LAN ID counts to determine the shared allocation; 34 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 13 cost centers used a form of the current year budgeted activities and/or dollars study; 12 cost centers used a form of prior year project assignments as a base for the current year distribution, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 11 cost centers used a form of Full Time Employee equivalent statistics for support; 9 cost centers used a form of miles of pipe installed existing and/or current year by service territory allocations; 8 cost centers used a form of gas meter counts and service territory allocations; 8 cost centers used a form of an allocation based on cases worked by regulated and non-regulated companies; 6 cost centers used an internal departmental multi-factor using LAN ID counts and voice phone or other electronic device counts; 6 cost

centers used an allocation of voice phone or other electronic device counts; 5 cost centers used a form of an allocation of space study identifying building square footage assigned; 4 cost centers used a form of weighted average allocation of the share service employees and activities planned for current year project assignments within the cost center, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 3 cost centers used an allocation of computer and/or server system and resource usage statistics; 2 cost centers used a current year study of dedicated shared support activities, which is adjusted as necessary when current year dedicated shared support activities begin or change and impact the current allocation; 2 cost centers used an internal department multi-factor applying meter ratio to specific budgeted activities; 2 cost centers used a form of weighted average of LAN id's; 2 cost centers used an internal departmental multi-factor using contract volume activity; 2 cost centers used a ratio of miles of distribution;
there was one use by a cost center of each of the remaining allocation methodologies: an allocation of Full Time Employee equivalent statistics for benefit; an internal departmental multi-factor using customer count, employee count and miles of existing pipe installed; a weighted average allocation of Sempra Energy Utility (including both Southern California Gas Company and San Diego Gas and Electric) gas revenue; a unit of allocation using ratio of horsepower in compressors and engines; a form of allocation using number of stakeholders to be reached; an assessment by the Pipeline Safety and Compliance Manager of time spent on Southern California Gas and San Diego Gas and Electric work activities; a current year study of budgeted activities by Affiliate; a weighted average of fleet activity related to maintenance repair units serviced in the prior year; an allocation of time based on volume of items mailed and payments processed; an allocation based on the weighted average of SEU Gas revenue; and, an allocation based on the combination of meters and ratio of miles of pipe.