THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR ☒ Resubmission No. ____	

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2017/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/forms/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/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.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 1,168 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 168 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent San Diego Gas & Electric Company	02 Year/Period of Report End of 2017/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 Eric Dalton	06 Title of Contact Person Regulatory Reporting Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 8330 Century Park Court, San Diego, CA 92123	

08 Telephone of Contact Person,*Including Area Code* (858) 503-5130	09 This Report Is (1) ☐ An Original (2) ☒ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 10/26/2018

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 Bruce A. Folkmann	03 Signature Bruce A. Folkmann	04 Date Signed *(Mo, Da, Yr)* 10/26/2018
02 Title VP, Controller, CFO, CAO, Treasurer		

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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: [ ] 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) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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) ☒ No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/Q4

CONTROL OVER RESPONDENT

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	N/A			
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	President	Scott D. Drury	400,000
2	Chief Development Officer	James P. Avery	375,200
3	Chief Information Officer	J. Chris Baker	368,400
4	Chief Human Resources Officer and Chief Administrative	Randall L. Clark	300,000
5	Vice President, Chief Financial Officer,	Bruce A. Folkmann	320,000
6	Chief Accounting Officer, Treasurer, Controller		
7	Chief Risk Officer and General Counsel	Erbin B. Keith	370,200
8	Chief Regulatory Officer	Lee Schavrien	376,900
9	Chief Operating Officer	Caroline A. Winn	370,000
10	Corporate Secretary	Kari McCulloch	231,138
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	Steven D. Davis, Director and Non-Executive Chairman (1)	San Diego, CA
2	Scott D. Drury, Director and President	San Diego, CA
3	Jeffrey W. Martin, Director (1)	San Diego, CA
4	Trevor I. Mihalik, Director (1)	San Diego, CA
5	G. Joyce Rowland, Director (1)	San Diego, CA
6	Caroline A. Winn, Director and Chief Operating Officer	San Diego, CA
7	Martha B. Wyrsch, Director (1)	San Diego, CA
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10	(1) Does not hold any offices with SDG&E but are officers	
11	of SDG&E's ultimate parent, Sempra Energy.	
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San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	ER17-470-000
3		
4		
5	FERC Electric Tariff, Volume No.11	ER17-1696-000
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8	FERC Electric Tariff, Volume No.11	ER17-1899-000
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11	FERC Electric Tariff, Volume No.11	ER17-1865-000
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14	FERC Electric Tariff, Volume No.11	ER17-547-000
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17	FERC Electric Tariff, Volume No.11	ER17-279-000
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20	FERC Electric Tariff, Volume No.11	ER17-551-000
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San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	20161201-5434	12/01/2016	ER17-470-000	TO4 Cycle 4 Formula Rate	FERC Electric Tariff, Volume No.11
3				Annual Informational Filing	
4					
5	20170526-5210	05/26/2017	ER17-1696-000	Cycle 6 Appendix X	FERC Electric Tariff, Volume No.11
6				Annual Informational Filing	
7					
8	20170626-5071	06/26/2017	ER17-1899-000	Post-Employment Benefits Other Than	FERC Electric Tariff, Volume No.11
9				Pensions ("PBOP") Filing	
10					
11	20170619-5129	06/19/2017	ER17-1865-000	TO4 Formula Depreciation	FERC Electric Tariff, Volume No.11
12				Rate Change Filing	
13					
14	20161214-5197	12/14/2016	ER17-547-000	2017 Reliability Service Balancing	FERC Electric Tariff, Volume No.11
15				Account ("RSBA") Filing	
16					
17	20161101-5188	11/01/2016	ER17-279-000	2017 Transmission Revenue Balancing	FERC Electric Tariff, Volume No.11
18				Account Adjustment	
19					
20	20161215-5114	12/15/2016	ER17-551-000	2017 Transmission Access Charge	FERC Electric Tariff, Volume No.11
21				Balancing Account Adjustment	
22				("TACBAA") Filing	
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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		
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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. SDGE amended its existing Greencraig I lease (effective 10/31/17) removing approximately 68,309 square feet of the premises while reducing rent by approximately 40%

   SDGE has vacated property located at: 10939 Technology Place, San Diego, CA 92127.

   SDGE has vacated property located at: 10949 Technology Place, San Diego, CA 92127.

   SDGE has vacated property located at: 6555 Nancy Ridge Drive, San Diego, CA 92121.

   SDGE has renewed its existing Market Creek Plaza Payment Branch Office on December 5, 2017.

   SDGE entered into a new office lease for the same building, approximately 45,021 square feet, located on 8690 Balboa Ave., San Diego, CA 92123.

   SDGE amended its existing Caspian lease, effective 12/31/2017, adding two additional five year options.

   SDGE amended its existing Greencraig II lease, effective 10/31/2017, increasing the size of the Premises by approximately 68,309 square feet while increasing rent by approximately 5%.

5. New TL13850 a Short Generator Interconnection was added at Boulevard East Substation. This consisted of a short segment, approximately 300 feet, of underground cable that SDG&E will own.

   New TL23080 and TL23081 each of which is a short section of underground cable, approximately 500 feet, connecting a new GIS Substation Terminal to the San Luis Rey Substation.

6. During 2017, San Diego Gas & Electric issued commercial paper with an average daily balance of $220.1 million and a maximum outstanding balance of $453.6 million. The year-end balance was $252.8 million.

   SDG&E had no long term debt issuances or maturities during the quarter ending 12/31/2017.

7. None

8. On September 1, 2017, SDG&E employees represented by the International Brotherhood of Electrical Workers (IBEW) Local 465 received a negotiated base rate increase of 3.25% affecting 1200 employees:

   Total annualized base wages for represented employees in 2017 were $4.38 million above 2016 base wages.

   Total annualized wages for represented employees including overtime in 2017 were $13.72 million above 2016 wages including overtime.

9. Please refer to the Legal Proceedings section of the Notes to the Financial Statements on page 123.64

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
Scott D. Drury	Chief Energy Supply Officer changed to President	Changed, 01/01/2017
Caroline A. Winn	Chief Energy Delivery Officer changed to Chief Operating Officer	Changed, 01/01/2017
John D. Jenkins	Elected as Vice President – Electric Engineering and Construction	Elected, 03/11/2017
Randall L. Clark	Vice President – Human Resources, Diversity and Inclusion changed to Chief Administrative Officer and Chief Human Resources Officer	Changed, 03/11/2017
David L. Geier	Vice President – Electric Transmission and Engineering changed to Senior Vice President – Electric Operations	Changed, 03/11/2017
Erbin B. Keith	Chief Regulatory & Risk Officer and General Counsel changed to Chief Risk Officer and General Counsel, and Assistant Secretary	Changed, 03/11/2017
Lee Schavrien	Chief Administrative Officer changed to Chief Regulatory Officer	Changed, 03/11/2017
John A. Sowers	Vice President – Electric Distribution changed to Senior Vice President – Asset Management	Changed, 03/11/2017
Katherine M. Speirs	Elected Vice President – Electric System Operations	Elected, 03/31/2017
James P. Avery	Resigned as Chief Development Officer	Resigned, 03/31/2017
Kenneth J. Deremer	Resigned as Assistant Treasurer	Resigned, 06/30/2017
Donny Widjaja	Elected as Assistant Treasurer	Elected, 07/01/2017
Rodger R. Schwecke	Vice President – Gas Transmission changed to Senior Vice President – Gas Transmission	Changed, 07/01/2017
Emily C. Shults	Vice President – Energy Procurement	Changed, 07/01/2017

	changed to Vice President - Energy Supply	
Erbin B. Keith	Resigned as Chief Risk Officer and General Counsel, and Assistant Secretary	Resigned, 09/15/2017
Diana L. Day	Elected as Acting General Counsel and Assistant Secretary	Elected, 09/16/2017
Neil P. Navin	Elected as Vice President - Gas Transmission	Elected, 10/07/2017
David L. Buczkowski	Vice President - Gas Engineering changed to Vice President - Gas Engineering & System Integrity	Changed, 10/07/2017
Jimmie I. Cho	Senior Vice President - Gas Operations and System Integrity changed to Senior Vice President - Gas Engineering and Distribution	Changed, 10/07/2017
Guillermina Orozco-Mejia	Vice President - Gas Operations changed to Vice President - Gas Distribution	Changed, 10/07/2017
Douglas M. Schneider	Vice President - Gas System Integrity and Gas Asset Management changed to Vice President - Gas Enterprise Asset Management	Changed, 10/07/2017
Rodger R. Schwecke	Senior Vice President - Gas Transmission changed to Senior Vice President - Gas Transmission & System Operations	Changed, 10/07/2017
Douglas M. Schneider		Deceased, 12/15/2017

Changes in Directors:

Scott D. Drury	Elected, 01/01/2017
Trevor I. Mihalik	Elected, 01/30/2017
Caroline A. Winn	Elected, 01/30/2017

14. None

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	18,390,733,610	16,560,921,577
3	Construction Work in Progress (107)	200-201	1,450,531,198	1,307,453,482
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		19,841,264,808	17,868,375,059
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,284,565,920	5,810,907,185
6	Net Utility Plant (Enter Total of line 4 less 5)		13,556,698,888	12,057,467,874
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)		13,556,698,888	12,057,467,874
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,790,994	5,946,616
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	82,663,273	182,186,711
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)		1,033,106,611	1,026,292,476
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		102,971,280	74,686,837
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,224,167,858	1,288,748,340
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		8,098,377	1,666,494
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		500	500
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		297,487,258	290,548,308
41	Other Accounts Receivable (143)		77,944,781	16,989,164
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,178,412	4,268,739
43	Notes Receivable from Associated Companies (145)		0	31,230,276
44	Accounts Receivable from Assoc. Companies (146)		426,650	875,047
45	Fuel Stock (151)	227	3,447,152	2,289,968
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	136,123,860	112,815,264
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	198,803,755	198,409,740

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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		82,663,273	182,186,711
54	Stores Expense Undistributed (163)	227	1,070,047	0
55	Gas Stored Underground - Current (164.1)		299,024	239,265
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		7,563	4,618
57	Prepayments (165)		60,107,301	188,552,215
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		2,427,536	714,901
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		69,780,000	67,615,000
62	Miscellaneous Current and Accrued Assets (174)		2,294,000	2,294,000
63	Derivative Instrument Assets (175)		145,375,780	132,560,020
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		102,971,280	74,686,837
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)		813,880,619	785,662,493
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,399,333	32,459,597
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	1,366,481	200,234,376
72	Other Regulatory Assets (182.3)	232	1,814,742,422	2,602,605,694
73	Prelim. Survey and Investigation Charges (Electric) (183)		355,845	117,519
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)		-1,743,983	2,015,793
77	Temporary Facilities (185)		87,692	0
78	Miscellaneous Deferred Debits (186)	233	150,127,818	23,389,953
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)		8,933,154	12,069,663
82	Accumulated Deferred Income Taxes (190)	234	193,614,853	316,952,547
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,200,883,615	3,189,845,142
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		17,795,630,980	17,321,723,849

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

The 13-month Average Electric Prepayments for 2017 is $44,443,462.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	end of 2017/Q4

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	479,665,369
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	4,266,831,380	4,310,137,617
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)	-8,217,268	-7,479,065
16	Total Proprietary Capital (lines 2 through 15)		5,596,415,214	5,640,459,654
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,573,220,000	4,348,934,000
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	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		11,674,567	10,660,618
24	Total Long-Term Debt (lines 18 through 23)		4,561,545,433	4,338,273,382
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,032,560,214	588,687,033
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		22,886,561	25,181,795
29	Accumulated Provision for Pensions and Benefits (228.3)		185,844,199	235,792,423
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		150,086,691	176,818,615
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		837,158,537	828,608,319
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,228,536,202	1,855,088,185
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		252,634,005	0
38	Accounts Payable (232)		533,763,816	496,331,988
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		40,399,413	43,228,051
41	Customer Deposits (235)		79,450,451	76,071,281
42	Taxes Accrued (236)	262-263	9,592,822	2,924,576
43	Interest Accrued (237)		41,258,087	44,771,962
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)		4,921,676	4,842,783
48	Miscellaneous Current and Accrued Liabilities (242)		284,219,634	191,563,413
49	Obligations Under Capital Leases-Current (243)		53,696,924	43,031,527
50	Derivative Instrument Liabilities (244)		199,865,892	224,679,048
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		150,086,691	176,818,615
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)		1,349,716,029	950,626,014
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		62,987,727	59,214,600
57	Accumulated Deferred Investment Tax Credits (255)	266-267	17,640,050	16,035,272
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	294,302,384	389,435,074
60	Other Regulatory Liabilities (254)	278	1,993,036,666	963,593,974
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)		1,588,514,956	2,236,989,173
64	Accum. Deferred Income Taxes-Other (283)		102,936,319	872,008,521
65	Total Deferred Credits (lines 56 through 64)		4,059,418,102	4,537,276,614
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		17,795,630,980	17,321,723,849

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	4,631,183,368	4,675,441,554		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,033,572,828	2,813,748,005		
5	Maintenance Expenses (402)	320-323	143,578,144	147,675,353		
6	Depreciation Expense (403)	336-337	514,716,512	476,502,991		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	76,951,462	72,759,995		
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)		46,619,051	59,819,081		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,510,600	381,765		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	133,981,724	130,167,481		
15	Income Taxes - Federal (409.1)	262-263	100,049,127			
16	- Other (409.1)	262-263	65,007,563	22,002,634		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	372,504,341	627,850,891		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	418,232,160	366,146,724		
19	Investment Tax Credit Adj. - Net (411.4)	266	1,604,778	-2,693,659		
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)		4,071,879,714	3,982,083,557		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		559,303,654	693,357,997		

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
4,088,935,308	4,175,564,018	547,004,881	504,127,587	-4,756,821	-4,250,051	2
						3
2,675,271,008	2,496,491,349	362,711,028	322,195,577	-4,409,208	-4,938,921	4
125,325,445	127,767,903	18,252,699	19,907,450			5
457,420,476	426,807,240	56,289,863	48,222,822	1,006,173	1,472,929	6
						7
64,357,703	61,447,582	12,593,759	11,312,413			8
15,744	15,744					9
46,619,051	59,819,081					10
						11
719,044	188,697	791,556	193,068			12
						13
116,043,046	114,403,679	17,258,690	15,129,316	679,988	634,486	14
147,421,808		-47,372,681				15
62,007,746	16,395,774	2,999,817	5,606,860			16
306,770,489	570,947,490	65,733,852	56,903,401			17
416,737,107	329,833,167	1,495,053	36,313,557			18
2,117,707	-2,180,730	-512,929	-512,929			19
						20
						21
						22
						23
						24
3,587,352,160	3,542,270,642	487,250,601	442,644,421	-2,723,047	-2,831,506	25
501,583,148	633,293,376	59,754,280	61,483,166	-2,033,774	-1,418,545	26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		559,303,654	693,357,997		
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)		35,206	10,231		
34	(Less) Expenses of Nonutility Operations (417.1)			-12,707		
35	Nonoperating Rental Income (418)		32,897	33,467		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		6,968,304	5,785,275		
38	Allowance for Other Funds Used During Construction (419.1)		63,269,244	46,452,775		
39	Miscellaneous Nonoperating Income (421)		355,197	3,203,447		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		70,660,848	55,497,902		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		250,048	250,048		
45	Donations (426.1)		5,758,393	7,234,648		
46	Life Insurance (426.2)		-6,138,140	-5,578,007		
47	Penalties (426.3)		113,152	1,942		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,461,950	1,916,220		
49	Other Deductions (426.5)		3,034,371	-682,248		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,479,774	3,142,603		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	657,648	647,229		
53	Income Taxes-Federal (409.2)	262-263	-295,350			
54	Income Taxes-Other (409.2)	262-263	-169,532	230,873		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	12,484,363	17,722,396		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,509,344	19,449,488		
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)		7,167,785	-848,990		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		59,013,289	53,204,289		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		185,808,926	176,236,940		
63	Amort. of Debt Disc. and Expense (428)		3,445,542	3,332,177		
64	Amortization of Loss on Reaquired Debt (428.1)		3,334,760	3,264,017		
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)			8,883		
68	Other Interest Expense (431)		13,446,610	9,283,327		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		21,031,665	15,132,370		
70	Net Interest Charges (Total of lines 62 thru 69)		185,004,173	176,992,974		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		433,312,770	569,569,312		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)		-549,655			
75	Net Extraordinary Items (Total of line 73 less line 74)		549,655			
76	Income Taxes-Federal and Other (409.3)	262-263	27,168,662			
77	Extraordinary Items After Taxes (line 75 less line 76)		-26,619,007			
78	Net Income (Total of line 71 and 77)		406,693,763	569,569,312		

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

Total Operating Revenues exludes amounts associated with interdepartmental transfers.

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

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

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

Eliminates interdepartmental transfers	$ (5,762,994)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	1,006,173
	$ (4,756,821)

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

Eliminates interdepartmental transfers	$ (6,284,095)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	2,034,044
	$ (4,250,051)

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

Total Operating Revenues 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: k

Eliminates interdepartmental transfers	$ (5,762,994)
Citizens Energy Corporation Operating Expenses	1,353,786
	$ (4,409,208)

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

Eliminates interdepartmental transfers	$ (6,284,096)
Citizens Energy Corporation Operating Expenses	1,345,175
	$ (4,938,921)

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	(1,830,787)
	$ 1,006,173

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	(1,364,031)
	$ 1,472,929

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

Citizens Energy Corporation Property Tax	$ 650,880
Citizens Energy Corporation Payroll Tax	29,108
	$ 679,988

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

Citizens Energy Corporation Property Tax	$ 604,652
Citizens Energy Corporation Payroll Tax	29,834
	$ 634,486

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

Modification of the Allowance 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 debt associated with the financing of the net revenue under-collections recorded in its regulatory balancing and memo accounts.

During the year, the average amount of short-term debt directly related to its balancing and memo accounts net under-collections excluded from the calculation of AFUDC rate, amount to $130.6 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $12.3 million.

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

Modification of the Allowance 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 debt associated with the financing of the net revenue under-collections recorded in its regulatory balancing and memo accounts.

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

Modification of the Allowance 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 debt associated with the financing of the net revenue under-collections recorded in its regulatory balancing and memo accounts.

During the year, the average amount of short-term debt directly related to its balancing and memo accounts net under-collections excluded from the calculation of AFUDC rate, amount to $130.6 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $12.3 million.

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

Modification of the Allowance 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 debt associated with the financing of the net revenue under-collections recorded in its regulatory balancing and memo accounts.

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

The extraordinary deduction for the SONGS impairment on line 74 of ($549,655) has a related tax amount of $223,962 and is included in 409.3.

As part of the income tax accounting subsequent to the 2017 Tax Cuts and Jobs Act tax reform legislation, SDG&E remeasured its deferred tax liabilities and deferred tax assets at the new federal corporate tax rate of 21%. Pursuant to this remeasurement, any items which were attributable to shareholders were recorded/offset to the income statement. SDG&E had a deferred tax asset on its books related to the SONGS book impairment losses recorded in 2014 and 2015. These impairment losses were attributable to shareholders, therefore the corresponding deferred tax asset was attributable to shareholders. The re-measurement of $26,944,700 related to this SONGS deferred tax asset is recorded as extraordinary taxes on line 76. On page 274, this amount is included in account 410.1.

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		4,310,137,617	3,892,862,778
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	ASU 2016-09 Stock Comp Adjustment			22,705,527
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			22,705,527
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		406,693,763	569,569,312
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			-450,000,000	(175,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-450,000,000	(175,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		4,266,831,380	4,310,137,617
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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)		4,266,831,380	4,310,137,617
	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) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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)	406,693,763	569,569,312
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	514,716,512	476,502,991
5	Impairment of Wildfire Asset	351,067,753	
6	Amortization of Unrecovered Plant and Regulatory Study Costs	123,586,257	132,594,820
7	Impairment of SONGS asset	-549,655	
8	Deferred Income Taxes (Net)	-11,808,100	259,977,075
9	Investment Tax Credit Adjustment (Net)	1,604,778	-2,693,659
10	Net (Increase) Decrease in Receivables	-69,701,497	-23,172,075
11	Net (Increase) Decrease in Inventory	-25,598,530	-4,904,978
12	Net (Increase) Decrease in Allowances Inventory	-14,715,000	-57,675,353
13	Net Increase (Decrease) in Payables and Accrued Expenses	37,179,517	3,353,668
14	Net (Increase) Decrease in Other Regulatory Assets	-724,150,341	613,871,664
15	Net Increase (Decrease) in Other Regulatory Liabilities	997,902,218	-413,530,027
16	(Less) Allowance for Other Funds Used During Construction	63,269,244	46,452,775
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: Net (Increase) Decrease in Prepayments and Other	135,712,144	-119,080,971
19	Net Increase (Decrease) in Accrued Interest and Taxes	1,520,629	2,060,789
20			
21	Other - Net	-159,481,176	-94,299,532
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,500,710,028	1,296,120,949
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,618,087,731	-1,439,047,600
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	-63,269,244	-46,452,775
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,554,818,487	-1,392,594,825
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	31,242,113	-30,916,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	COLI - Corporate Owned Life Insurance - Net	5,859,427	
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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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			
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	Decommissioning Trust Fund Purchase	-1,313,621,571	-1,033,971,880
54	Decommissioning Trust Fund Sales	1,313,621,571	1,133,846,875
55	Increase (Decrease) in Customer Advances for Construction	1,802,797	3,235,232
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,515,914,150	-1,320,400,598
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	398,216,000	498,375,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Other: LTD Issuance Cost Amortization	-3,500,000	-3,250,000
66	Net Increase in Short-Term Debt (c)	252,634,005	-114,260,980
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	647,350,005	380,864,020
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-175,714,000	-194,364,000
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	-450,000,000	-175,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	21,636,005	11,500,020
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	6,431,883	-12,779,629
87			
88	Cash and Cash Equivalents at Beginning of Period	1,666,994	14,446,623
89			
90	Cash and Cash Equivalents at End of period	8,098,877	1,666,994

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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

A. Notes for Statement of Cash Flows

Supplemental Disclosure of Cash Flow Information:	12/31/2017
Income tax payments (refunds), net	$ 27,082,264
Interest payments, net of amounts capitalized	$ 173,000,832
Reconciliation of cash and cash equivalents at December 31, 2017:	
Account 131 Cash	$ 8,098,377
Account 135 Working Funds	500
Account 136 Temporary Cash Investments	0
	$ 8,098,877

Supplemental Disclosure of Non-Cash Investing Activities:	
Nuclear facility plant reclassified to regulatory asset, net of depreciation and amortization	$ 0
Increase (Decrease) in capital lease obligation for investments in property, plant and equipment	$ 500,000,000
Accrued Capital Expenditures	$ 216,827,000

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, 2017, as filed with the Securities and Exchange Commission (SEC) on February 27, 2018. 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 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 573-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, 2017, the capital lease was valued at $595 million, and the corresponding capital lease obligation with a 10-year term was valued at $354 million.

At December 31, 2017, the future minimum lease payments and present value of the net minimum lease payments under these capital leases were as follows:

(Dollars in millions)		
2018	$	67
2019		331
Total minimum lease payments(1)		398
Less: interest(2)		(44)
Present value of net minimum lease payments(3)	$	354

(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 $41 million in Current Portion of Capital Lease Obligation and $313 million in Long-Term Capital Lease Obligation on the Balance Sheet at December 31, 2017.*

The annual amortization charge for the OMEC power purchase agreement was $38 million for 2017 and $35 million for 2016.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

BASIS OF PRESENTATION

This is a report of San Diego Gas & Electric Company (SDG&E). SDG&E's common stock is wholly owned by Enova Corporation, which is a wholly owned subsidiary of Sempra Energy. References in this report to "we" and "our" are to SDG&E, unless otherwise indicated by the context.

Balance Sheet Reclassifications

We have made certain balance sheet reclassifications at December 31, 2016 to conform to the current year presentation. Line item captions for various types of regulatory assets and liabilities have been combined or separated into four new line items: current and noncurrent regulatory assets and current and noncurrent regulatory liabilities. The details of regulatory assets and liabilities are provided in Note 11. Additionally, greenhouse gas allowances have been separated from other current assets and sundry assets and greenhouse gas obligations have been separated from other current liabilities and deferred credits and other into four new line items: current and noncurrent greenhouse gas allowances and current and noncurrent greenhouse gas obligations. These reclassifications and related disclosures had no effect on our financial position as of December 31, 2016 and are intended to provide additional clarity into our financial position. The following table summarizes the balance sheet line items affected by these reclassifications:

SDG&E – BALANCE SHEET RECLASSIFICATIONS AT DECEMBER 31, 2016

(Dollars in millions)

	As previously presented	As currently presented
Current assets:		
Regulatory assets	$ 81	$ 340
Greenhouse gas allowances	—	16
Regulatory balancing accounts – net undercollected	259	—
Other	19	3
Other assets:		
Regulatory assets	—	2,012
Greenhouse gas allowances	—	182
Deferred taxes recoverable in rates	1,014	—
Other regulatory assets	998	—
Sundry	358	176
Current liabilities:		
Greenhouse gas obligations	—	16
Other	81	65
Deferred credits and other liabilities:		
Regulatory liabilities	—	1,725
Greenhouse gas obligations	—	72
Regulatory liabilities arising from removal obligations	1,725	—
Deferred credits and other	416	344

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.

Subsequent Events

We evaluated events and transactions that occurred after December 31, 2017 through the date the financial statements were issued, and in the opinion of management, the accompanying statements reflect all adjustments and disclosures necessary for a fair presentation.

EFFECTS OF REGULATION

Our accounting policies and financial statements reflect the application of U.S. GAAP provisions governing rate-regulated operations and the policies of the CPUC and the FERC. 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.

Determining probability of recovery of regulatory assets 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;
- 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 in Notes 10 and 11.

FAIR VALUE MEASUREMENTS

We measure certain assets and liabilities at fair value on a recurring basis, primarily nuclear decommissioning and benefit plan trust assets and derivatives. We also measure certain assets at fair value on a non-recurring basis in certain circumstances. These assets can include goodwill, intangible assets, equity method investments and other long-lived assets.

"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 – Pricing inputs are quoted prices 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, primarily in the NDT and benefit plan trusts, 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 listed equities, domestic corporate bonds, municipal bonds and other foreign bonds, primarily in the NDT and benefit plan trusts, and non-exchange-traded derivatives such as interest rate instruments and over-the-counter 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 consist of CRRs and fixed-price electricity positions at SDG&E.

CASH AND CASH EQUIVALENTS

Cash equivalents are highly liquid investments with original 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,		
	2017	2016	2015
Allowances for collection of receivables at January 1	$ 8	$ 9	$ 7
Provisions for uncollectible accounts	8	6	7
Write-offs of uncollectible accounts	(7)	(7)	(5)
Allowances for collection of receivables at December 31	$ 9	$ 8	$ 9

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 collection allowances 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 using the LIFO method. As inventories are sold, differences between the LIFO valuation and the estimated replacement cost are reflected in customer rates. These differences are generally temporary, but may become permanent if the natural gas inventory withdrawn from storage during the year is not replaced by year end. We generally value materials and supplies at the lower of average cost or net realizable value.

The components of inventories are as follows:

INVENTORY BALANCES AT DECEMBER 31 *(Dollars in millions)*	Natural gas		Materials and supplies		Total	
	2017	2016	2017	2016	2017	2016
SDG&E	$ 4	$ 2	$ 97	$ 75	$ 101	$ 77

INCOME TAXES

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

Under the regulatory accounting treatment required for flow-through temporary differences, as discussed in Note 4, 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 ETR.

We provide additional information about income taxes in Note 4.

GREENHOUSE GAS ALLOWANCES AND OBLIGATIONS

SDG&E is required by California AB 32 to acquire GHG allowances for every metric ton of carbon dioxide equivalent emitted into the atmosphere during electric generation and natural gas transportation. Many GHG allowances are allocated to us on behalf of our customers at no cost. We record purchased and allocated GHG allowances at the lower of weighted-average cost or market. 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 balance costs and revenues associated with the GHG program through regulatory balancing accounts. We remove the assets and liabilities from the balance sheets as the allowances are surrendered.

RENEWABLE ENERGY CERTIFICATES

RECs are energy rights established by governmental agencies for the environmental and social promotion 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 energy PPAs, internal generation or separate purchases in the market to comply with the RPS established by the governmental agencies. RECs provide documentation for the generation of a unit of renewable energy that is used to verify compliance with the RPS. The cost of RECs at SDG&E is recorded in Cost of Electric Fuel and Purchased Power, which is recoverable in rates, on the Statements of Operations.

PROPERTY, PLANT AND EQUIPMENT

PP&E primarily represents the buildings, equipment and other facilities used to provide natural gas and electric utility services, including construction work in progress. PP&E also includes lease improvements and other equipment, which we discuss further in Note 12.

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 other PP&E 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.

We discuss assets collateralized as security for certain indebtedness in Note 3.

PROPERTY, PLANT AND EQUIPMENT BY MAJOR FUNCTIONAL CATEGORY

(Dollars in millions)

	PP&E at December 31,		Depreciation rates for years ended December 31,		
	2017	2016	2017	2016	2015

SDG&E:					
Natural gas operations	$ 2,186	$ 1,897	2.40%	2.40%	2.52%
Electric distribution	6,975	6,497	3.92	3.86	3.79
Electric transmission(1)	5,626	5,152	2.71	2.66	2.62
Electric generation(2)	2,470	1,937	4.05	4	3.89
Other electric(3)	1,114	1,059	5.54	5.66	5.73
Construction work in progress(1)	1,451	1,307	NA	NA	NA
Total SDG&E	19,822	17,849			

(1) At December 31, 2017, includes $440 million in electric transmission assets and $29 million in construction work in progress related to SDG&E's 92-percent interest in the Southwest Powerlink 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. SDG&E's share of operating expenses is included in its Statements of Operations.

(2) Includes capital lease assets of $1,352 million and $853 million at December 31, 2017 and 2016, respectively.

(3) Includes capital lease assets of $22 million and $21 million at December 31, 2017 and 2016, respectively.

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 our Statement of Operations is as follows:

DEPRECIATION EXPENSE
(Dollars in millions)

	Years ended December 31,		
	2017	2016	2015
SDG&E	$ 593	$ 548	$ 518

Accumulated depreciation on our Balance Sheet is as follows:

ACCUMULATED DEPRECIATION
(Dollars in millions)

	December 31,	
	2017	2016
Accumulated depreciation:		
Electric(1)	$ 4,195	$ 3,841
Natural gas	756	721
Total accumulated depreciation	$ 4,951	$ 4,562

(1) *Includes accumulated depreciation for capital lease assets of $288 million and $242 million at December 31, 2017 and 2016, respectively. Includes $241 million at December 31, 2017 related to SDG&E's 92-percent interest in the Southwest Powerlink transmission line, jointly owned by SDG&E and other utilities.*

We finance our construction projects with debt 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 PP&E. 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.

We capitalize interest costs incurred to finance capital projects. We also capitalize interest on equity method investments that have not commenced planned principal operations.

Interest capitalized and AFUDC are as follows:

CAPITALIZED FINANCING COSTS
(Dollars in millions)

	Years ended December 31,		
	2017	2016	2015
SDG&E	$ 85	$ 62	$ 51

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 may be 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 the asset is placed into service), and accreting the obligation until the liability is settled. Our 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 transmission systems
- natural gas distribution systems
- hazardous waste storage facilities
- asbestos-containing construction materials
- decommissioning of nuclear power facilities
- electric distribution and transmission systems
- energy storage 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)

	SDG&E	
	2017	2016
Balance as of January 1[1]	$ 828	$ 826
Accretion expense	39	38
Liabilities incurred and acquired	17	—
Deconsolidation and reclassification	—	—
Payments	(61)	(46)
Revisions[2]	14	10
Balance at December 31[1]	$ 837	$ 828

(1) *The 2016 reported amount changed from the prior year to remove consolidated OMEC ARO.*

(2) *In 2017, revised estimates were primarily related to underground natural gas storage facilities and wells. In 2016, revised estimates were related to changes in the cost of removal rates primarily for natural gas assets based on updated cost studies approved in the 2016 GRC FD.*

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 and amounts are estimable.

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:

- certain hedging activities
- 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

The Statement of Comprehensive Income (Loss) shows the changes in the components of OCI. The following table presents the changes in 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 (1)
(Dollars in millions)

	Pension and other postretirement benefits	Total accumulated other comprehensive income (loss)
SDG&E:		
Balance as of December 31, 2014	$ (12)	$ (12)
OCI before reclassifications	3	3
Amounts reclassified from AOCI	1	1
Net OCI	4	4
Balance as of December 31, 2015	(8)	(8)
OCI before reclassifications	(1)	(1)
Amounts reclassified from AOCI	1	1
Net OCI	—	—
Balance as of December 31, 2016	(8)	(8)
OCI before reclassifications	(1)	(1)
Amounts reclassified from AOCI	1	1
Net OCI	—	—
Balance as of December 31, 2017	$ (8)	$ (8)

(1) All amounts are net of income tax, if subject to tax.

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

Details about accumulated	Amounts reclassified from accumulated	Affected line item on

other comprehensive income (loss) components	other comprehensive income (loss)			Statement of Operations
	Years ended December 31,			
	2017	2016	2015	
Pension and other postretirement benefits:				
Amortization of actuarial loss(1)	$ 1	$ 1	$ 1	
Total reclassifications for the period, net of tax	$ 1	$ 1	$ 1	

(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 our customers of electricity, natural gas, and from other 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 a subsequent period. 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 their 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 a subsequent period. SDG&E may also record revenue from CPUC-approved incentive awards, some of which require approval by the CPUC prior to being recognized. SDG&E bids and self-schedules its generation into the CAISO energy market on a day-ahead and real-time basis and self-schedules power to serve the demand of its customers. Generally, SDG&E is a net purchaser of power. The CAISO settles SDG&E costs and revenues on an hourly and real-time net basis.

OPERATION AND MAINTENANCE EXPENSES

Operation and Maintenance includes O&M 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 unconsolidated affiliates at SDG&E are as follows:

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

	December 31, 2017	December 31, 2016
Sempra Energy[1]	$ —	$ 3
Various affiliates	—	1
Total due from unconsolidated affiliates – current	$ —	$ 4
Sempra Energy	$ (30)	$ —
SoCalGas	(4)	(8)
Various affiliates	(6)	(7)
Total due to unconsolidated affiliates – current	$ (40)	$ (15)
Income taxes due from Sempra Energy[2]	$ 27	$ 159

(1) *At December 31, 2016, net receivable included outstanding advances to Sempra Energy of $31 million at an interest rate of 0.68 percent.*

(2) *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 having always filed a separate return.*

Revenues and cost of sales from unconsolidated affiliates are as follows:

REVENUES AND COST OF SALES FROM UNCONSOLIDATED AFFILIATES
(Dollars in millions)

	Years ended December 31, 2017	2016	2015
Revenues:	$ 8	$ 7	$ 10
Cost of Sales:	$ 71	$ 64	$ 49

California Utilities

Sempra Energy, 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 the federal funds rate plus a margin of 13 to 20 bps, depending on the loan balance.

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 O&M.

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 presented net in SoCalGas' Statements of Operations.

SDG&E has a 20-year contract for up to 155 MW of renewable power supplied from the Energía Sierra Juárez wind power 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 of the our capital structure limits the amount available for dividends and loans to Sempra Energy. At December 31, 2017, Sempra Energy could have received combined loans and dividends of approximately $469 million, funded by long-term debt issuance from SDG&E.

The payment and amount of future dividends are at the discretion of our board 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 our authorized capital structure. The authorized percentage at December 31, 2017 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, 2017, SDG&E's restricted net assets were $5.1 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,		
	2017	2016	2015
Allowance for equity funds used during construction	$ 63	$ 46	$ 37
Interest on regulatory balancing accounts, net	3	3	3
Sundry, net	(2)	1	(4)
Total	$ 64	$ 50	$ 36

NOTE 2. NEW ACCOUNTING STANDARDS

We describe below recent pronouncements that have had or may have a significant effect on our financial condition, results of operations, cash flows or disclosures.

ASU 2014-09, "Revenue from Contracts with Customers," ASU 2015-14, "Deferral of the Effective Date," ASU 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)," ASU 2016-10, "Identifying Performance Obligations and Licensing" and ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients": ASU 2014-09 adds ASC 606 to provide accounting guidance for the recognition of 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. Amending ASU 2014-09, ASU 2016-08 clarifies the implementation guidance on principal versus agent considerations, ASU 2016-10 clarifies the determination of whether a good or service is separately identifiable from other promises and revenue recognition related to licenses of intellectual property, and ASU 2016-12 provides guidance on transition, collectability, noncash consideration, and the presentation of sales and other similar taxes. The ASUs are codified in ASC 606.

ASU 2015-14 defers the effective date of ASC 606 by one year for all entities and permits early adoption on a limited basis. For public entities, ASC 606 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 adopted ASC 606 on January 1, 2018, applying the modified retrospective transition method to all contracts as of January 1, 2018 and elected to use certain practical expedients available under the transition guidance. The impact from adoption was not material to our financial statements, and the timing of our revenue recognition has remained materially consistent before and after the adoption of ASC 606. Our additional disclosures about the nature, amount, timing and uncertainty of revenues arising from contracts with customers will be included in our Notes to Financial Statements beginning in the first quarter of 2018.

ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities": In addition to the presentation and disclosure requirements for financial instruments, ASU 2016-01 requires entities to measure equity investments, other than those accounted for under the equity method, at fair value and recognize changes in fair value in net income. Entities will no longer be able to use the cost method of accounting for equity securities. However, for equity investments without readily determinable fair values that do not qualify for the practical expedient to estimate fair value using net asset value per share, entities may elect a measurement alternative that will allow those investments to be recorded at cost, less impairment, and adjusted for subsequent observable price changes. 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, except for equity investments without readily determinable fair values, for which the guidance will be applied prospectively. There is an outstanding FASB exposure draft which clarifies that the prospective transition approach for equity investments without readily determinable fair values is meant only for instances in which the measurement alternative is elected.

For public entities, ASU 2016-01 is effective for fiscal years beginning after December 15, 2017. We adopted ASU 2016-01 on January 1, 2018 and it will not materially affect our financial condition, results of operations or cash flows.

ASU 2016-02, "Leases" and ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842": 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 exclude from the balance sheet those 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 provisions of U.S. GAAP, other than certain changes to align lessor accounting to specific changes made to lessee accounting and ASC 606. ASU 2016-02 also requires new qualitative and quantitative disclosures for both lessees and lessors. ASU 2018-01 allows entities to elect a transition practical expedient that would exclude application of ASU 2016-02 to land easements that existed prior to its adoption, if they were not accounted for as leases under previous U.S. GAAP.

For public entities, these ASUs are effective for fiscal years beginning after December 15, 2018, with early adoption permitted, and are effective for interim periods in the year of adoption. ASU 2016-02 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 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 begin recognizing right-of-use assets and lease liabilities for all operating leases on the balance sheet at the reporting date. We are currently evaluating the effect of the standards on our ongoing financial reporting and plan to adopt the standards on January 1, 2019. As part of our evaluation, we formed a steering committee, are compiling our population of contracts and are preparing our lease accounting assessments. Based on our assessment to date, we have determined that we will elect the practical expedients available under the transition guidance described above. We continue to monitor outstanding issues currently being addressed by the FASB, including guidance under a FASB exposure draft that would allow entities an optional transition method to apply ASU 2016-02 in the period of adoption rather than in the earliest period presented. Conclusions that the FASB reaches on outstanding issues may impact our application of these ASUs.

ASU 2016-13, "Measurement of Credit Losses on Financial Instruments": ASU 2016-13 changes how entities will measure credit losses for most financial assets and certain other instruments. The standard introduces an "expected credit loss" impairment model that requires immediate recognition of estimated credit losses expected to occur over the remaining life of most financial assets measured at amortized cost, including trade and other receivables, loan commitments and financial guarantees. ASU 2016-13 also requires use of an allowance to record estimated credit losses on available-for-sale debt securities and expands disclosure requirements regarding an entity's assumptions, models and methods for estimating the credit losses.

For public entities, ASU 2016-13 is effective for fiscal years beginning after December 15, 2019, with early adoption permitted for fiscal years beginning after December 15, 2018. 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.

ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments" and ASU 2016-18, "Restricted Cash": ASU 2016-15 provides guidance on how certain cash receipts and cash payments are to be presented and classified in the statement of cash flows to reduce diversity in practice. Of the eight issues addressed in ASU 2016-15, we were impacted by the following issues:

- Issue 1 – debt prepayment or debt extinguishment costs
- Issue 3 – contingent consideration payments made after a business combination
- Issue 5 – proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies)

ASU 2016-18 requires amounts classified as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. A reconciliation between the balance sheet and the statement of cash flows must be disclosed when the balance sheet includes more than one line item for cash, cash equivalents, restricted cash and restricted cash equivalents. ASU 2016-15 and ASU 2016-18 must be adopted retrospectively. We early adopted ASU 2016-15 and ASU 2016-18 in the fourth quarter of 2017

Upon adoption of ASU 2016-15 and ASU 2016-18, for SEC reporting purposes, the SDG&E Consolidated Statement of Cash Flows for the years ended December 31, 2016 and 2015 were impacted as follows:

IMPACT FROM ADOPTION OF ASU 2016-15 AND ASU 2016-18(1)
(Dollars in millions)

	Years ended December 31,					
	2016			2015		
	As previously reported	Effect of adoption	As adjusted	As previously reported	Effect of adoption	As adjusted
SDG&E Consolidated Statements of Cash Flows:						
Cash flows from operating activities:						
Changes in other assets	$ (16)	$ (4)	$ (20)	$ (122)	$ (3)	$ (125)
Net cash provided by operating activities	1,327	(4)	1,323	1,664	(3)	1,661
Cash flows from investing activities:						
Increases in restricted cash	(49)	49	—	(39)	39	—
Decreases in restricted cash	60	(60)	—	35	(35)	—
Other	—	6	6	—	5	5
Net cash used in investing activities	(1,319)	(5)	(1,324)	(1,086)	9	(1,077)
Cash flows from financing activities:						
Other(2)	(4)	(2)	(6)	(2)	(2)	(4)
Net cash used in financing activities	(20)	(2)	(22)	(566)	(2)	(568)
(Decrease) increase in cash and cash equivalents	(12)	12	—	12	(12)	—
(Decrease) increase in cash, cash equivalents, and restricted cash	—	(23)	(23)	—	16	16
Cash and cash equivalents, January 1	20	(20)	—	8	(8)	—
Cash, cash equivalents and restricted cash, January 1	—	43	43	—	27	27
Cash and cash equivalents, December 31	8	(8)	—	20	(20)	—
Cash, cash equivalents and restricted cash, December 31	—	20	20	—	43	43

(1) *Table is based on the SDG&E Consolidated Statement of Cash Flows, which includes OMEC as a consolidated entity, for purposes of SEC reporting.*

(2) *Previously labeled "Debt issuance costs."*

ASU 2017-01, "Clarifying the Definition of a Business": ASU 2017-01 narrows the definition of a business and provides a framework to assist entities in determining whether a transaction involves an asset or a business. Specifically, the ASU provides a "screen" for determining when an integrated set of assets and activities (collectively referred to as a "set") is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or group of similar identifiable assets, the set is not a business. If the screen threshold is not met, a set cannot be considered a business unless it includes an input and a substantive process that together significantly contribute to the ability to create outputs. ASU 2017-01 must be applied prospectively on or after the effective date. Early adoption is permitted. We early adopted ASU 2017-01 on July 1, 2017.

ASU 2017-05, "Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets": ASU 2017-05 clarifies the scope of accounting for the derecognition or partial sale of nonfinancial assets to exclude all businesses and nonprofit activities. ASU 2017-05 also provides a definition for in-substance nonfinancial assets and additional guidance on partial sales of nonfinancial assets. For public entities, ASU 2017-05 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. Entities may apply a full retrospective or modified retrospective approach. Under a modified retrospective approach, entities are required to apply the guidance to any transactions that are not completed as of the adoption date. We adopted the standard in conjunction with our adoption of ASC 606 on January 1, 2018 using the modified retrospective transition method. We do not expect it to have a material impact on our financial condition, results of operations or cash flows.

ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost": ASU 2017-07 requires the service cost component of net periodic benefit costs to be presented in the same income statement line item as other employee compensation costs arising from services rendered during the period and the other components of net periodic benefit costs to be presented separately outside of operating income. The guidance also allows only the service cost component to be eligible for capitalization. For public entities, ASU 2017-07 is effective for annual reporting periods beginning after December 15, 2017, with early adoption permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. Amendments are to be applied retrospectively for presentation of costs and prospectively for capitalization of service costs. The guidance allows a practical expedient that permits use of previously disclosed service costs and other costs from the pension and other postretirement benefit plan note in the comparative periods as appropriate estimates when retrospectively changing the presentation of these costs in the statement of operations. We adopted the standard on January 1, 2018 and elected the practical expedient available under the transition guidance.

In 2018, we expect the adoption of ASU 2017-07 to have the following impact on our Statement of Operations for the years ended December 31, 2017 and 2016:

EXPECTED IMPACT FROM ADOPTION OF ASU 2017-07
(Dollars in millions)

	Years ended December 31,			
	2017		2016	
	As reported	Recast	As reported	Recast
Statement of Operations:				
Operation and maintenance	$ 1,003	$ 1,007	$ 1,019	$ 1,033
Operating income	680	676	975	961
Other income, net	64	68	50	64

ASU 2017-12, "Targeted Improvements to Accounting for Hedging Activities": ASU 2017-12 changes the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge accounting results. More specifically, the guidance expands the exposures that can be hedged to align with an entity's risk management strategies, alleviates documentation requirements, eliminates the concept of recognizing periodic hedge ineffectiveness for cash flow and net investment hedges and requires entities to present the entire change in the fair value of a hedging instrument in the same income statement line item as the earnings effect of the hedged item. For public entities, ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. If an entity early adopts ASU 2017-12 in an interim period, any transition adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. Entities will adopt ASU 2017-12 by applying a modified retrospective approach to the accounting for existing hedging relationships and will prospectively apply the new presentation and disclosure requirements. Transition elections are available for all hedges that exist at the date of adoption. We early adopted ASU 2017-12 on January 1, 2018, and it will not materially affect our financial condition, results of operations or cash flows.

ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income": ASU 2018-02 contains amendments that allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the TCJA. Under ASU 2018-02, an entity will be required to provide certain disclosures regarding stranded tax effects, including its accounting policy related to releasing the income tax effects from AOCI. The amendments in this update can be applied either as of the beginning of the period of adoption or retrospectively as of the date of enactment of the TCJA and to each period in which the effect of the TCJA is recognized. For public entities, ASU 2018-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods therein, with early adoption permitted. We are currently evaluating the effect of the standard on our financial reporting and have not yet selected the adoption method or the year in which we will adopt the standard.

NOTE 3. DEBT AND CREDIT FACILITIES

LINES OF CREDIT

SDG&E and SoCalGas have a combined $1 billion, five-year syndicated revolving credit agreement expiring in October 2020.

PRIMARY U.S. COMMITTED LINES OF CREDIT
(Dollars in millions)

	At December 31, 2017		
	Total facility	Commercial paper outstanding(1)	Available unused credit
California Utilities(2):			
SDG&E	$ 750	$ (253)	$ 497
SoCalGas	750	(116)	634
Less: subject to a combined limit of $1 billion for both utilities	(500)	—	(500)
Total	$ 1,000	$ (369)	$ 631

(1) Because the commercial paper programs are supported by these lines, we reflect the amount of commercial paper outstanding as a reduction to the available unused credit.
(2) The facility 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. No letters of credit were outstanding at December 31, 2017.

Related to the committed lines of credit in the table above:

- JPMorgan Chase Bank, N.A. serves as administrative agent for the California Utilities combined facility.
- Each facility has a syndicate of 21 lenders. No single lender has greater than a 7-percent share in any facility.
- SDG&E must maintain a ratio of indebtedness to total capitalization (as defined in each agreement) of no more than 65 percent at the end of each quarter. SDG&E is in compliance with this and all other financial covenants under its respective credit facility at December 31, 2017.
- Borrowings bear interest at benchmark rates plus a margin that varies with the borrowing utility's credit rating.
- The California Utilities' obligations under their 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.

WEIGHTED-AVERAGE INTEREST RATES

The weighted-average interest rate on total short-term debt at SDG&E was 1.65 percent at December 31, 2017.

LONG-TERM DEBT

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

LONG-TERM DEBT

(Dollars in millions)

	December 31, 2017	December 31, 2016
First mortgage bonds (collateralized by plant assets):		
Bonds at variable rates (1.151% at December 31, 2016) March 9, 2017	$ —	$ 140
1.65% July 1, 2018(1)	161	161
3% August 15, 2021	350	350
1.914% payable 2015 through February 2022	161	197
3.6% September 1, 2023	450	450
2.5% May 15, 2026	500	500
6% June 1, 2026	250	250
5.875% January and February 2034(1)	176	176
5.35% May 15, 2035	250	250
6.125% September 15, 2037	250	250
4% May 1, 2039(1)	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
3.75% June 1, 2047	400	—
	$ 4,573	$ 4,349
Capital lease obligations:		
Purchased-power contracts	1,085	631
Other	1	1
	$ 1,086	$ 632
	5,659	4,981
Current portion of long-term debt	(251)	(219)
Unamortized discount on long-term debt	(11)	(11)
Unamortized debt issuance costs	(33)	(32)
Total SDG&E	$ 5,364	$ 4,719

(1) Callable long-term debt not subject to make-whole provisions

MATURITIES OF LONG-TERM DEBT(1) *(Dollars in millions)*	
2018(2)	$ 197
2019(2)	36
2020	36
2021	385
2022	18
Thereafter	3,901
Total	$ 4,573

(1) *Excludes capital lease obligations, build-to-suit lease, market value adjustments for interest rate swaps, discounts, premiums and debt issuance costs.*

(2) *The amounts reported in 2016 included debt held by OMEC which have been removed from the reported table above.*

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, 2017 is callable subject to premiums:

CALLABLE LONG-TERM DEBT *(Dollars in millions)*	
Not subject to make-whole provisions	$ 412
Subject to make-whole provisions	4,161

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 our 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 additional first mortgage bonds of $4.7 billion at December 31, 2017.

In June 2017, SDG&E publicly offered and sold $400 million of 3.75-percent, first mortgage bonds maturing in June 2047. SDG&E used the proceeds from the offering to repay outstanding commercial paper.

OTHER LONG-TERM DEBT

In 2015, SDG&E entered into a CPUC-approved 25-year PPA with a peaker plant facility. Construction of the peaker plant facility was completed and delivery of contracted power commenced in June 2017, at which time we recorded a $500 million capital lease obligation on SDG&E's Balance Sheet.

INTEREST RATE SWAPS

We discuss our fair value and cash flow hedging interest rate swaps in Note 7.

NOTE 4. INCOME TAXES

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

RECONCILIATION OF FEDERAL INCOME TAX RATES TO EFFECTIVE INCOME TAX RATES

	Years ended December 31,		
	2017	2016	2015
U.S. federal statutory income tax rate	35%	35%	35%
Depreciation	7	5	4
Effects of the TCJA	5	—	—
State income taxes, net of federal income tax benefit	3	5	5
Repairs expenditures	(8)	(4)	(4)
Self-developed software expenditures	(6)	(3)	(3)
Allowance for equity funds used during construction	(4)	(2)	(2)
Resolution of prior years' income tax items	(4)	(1)	(2)
Share-based compensation	—	(1)	—
Other, net	—	(1)	—
Effective income tax rate	28%	33%	33%

On December 22, 2017, the TCJA was signed into law. This legislation significantly changes the IRC. Under U.S. GAAP, certain effects of the TCJA are required to be recognized upon enactment, and, as a result, SDG&E recorded the related effects in 2017.

The TCJA reduces the U.S. statutory corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018, which will be applied to future U.S. earnings. U.S. GAAP requires that deferred income tax assets and liabilities, including NOLs, be remeasured at the income tax rate expected to apply when those temporary differences reverse and that the effects of any change to such income tax rate be recognized in the period when the change was enacted. This remeasurement resulted in significant reductions in deferred income tax balances at SDG&E.

The remeasurement of deferred income tax balances at SDG&E resulted in excess deferred income taxes that previously have been collected from ratepayers at the higher rate. These excess deferred income taxes have been recorded as regulatory liabilities as of December 31, 2017 and will be refunded to ratepayers in accordance with the IRC's normalization provisions and as determined by the CPUC and FERC.

SDG&E's impact was primarily offset with adjustments to regulatory liabilities, however, SDG&E recorded $28 million of income tax expense for the year ended December 31, 2017 associated with the TCJA.

EFFECTS OF THE TAX CUTS AND JOBS ACT OF 2017 *(Dollars in millions)*		
Balance Sheet:		
Decrease in net deferred income tax liabilities due to remeasurement	$	(1,400)
Increase in net regulatory liabilities from remeasurement of deferred income tax assets and liabilities	$	1,428
Statement of Operations:		
Income tax expense related to remeasurement of deferred Income tax assets and liabilities	$	28
Total increase in income tax expense	$	28

We recorded the effects of the TCJA in 2017 using our best estimates and the information available to us through the date the financial statements were issued. However, our analysis is ongoing and as such, the income tax effects that we have recorded are provisional.

As permitted by and in accordance with the guidance issued by the SEC, we may adjust our provisional estimates in future reporting periods throughout 2018 as we complete our analysis and as more information becomes available, and these adjustments may affect earnings. Events and information that may result in adjustments to our provisional estimates include interpretations or rulings by the U.S. Department of the Treasury or states, and the filing of our 2017 income tax.

For SDG&E, 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 ETR. As a result, changes in the relative size of these items compared to pretax income, from period to period, can cause variations in the ETR. 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 2016 GRC FD issued by the CPUC in June 2016 required SDG&E to establish a two-way income tax expense memorandum account to track certain revenue variances resulting from certain differences between the income tax expense forecasted in the GRC and the income tax expense incurred from 2016 through 2018. The tracking accounts will remain open until the CPUC decides to close the accounts, which we expect will be reviewed in the 2019 GRC proceedings. We expect that certain amounts recorded in the tracking accounts may give rise to regulatory assets or liabilities. We discuss the tracking accounts further in Note 11.

Pretax book income decreased in 2016 compared to 2015 at SDG&E primarily due to the reallocation of 2012-2015 income tax benefits generated from income tax repairs deductions to ratepayers pursuant to the 2016 GRC FD, as we discuss in Note 11. Also, pretax income remained lower in 2017 due to the write-off of SDG&E's wildfire regulatory asset, as we discuss in Note 12.

The components of income tax expense are as follows:

INCOME TAX EXPENSE (BENEFIT)
(Dollars in millions)

	Years ended December 31,		
	2017	2016	2015
Current:			
U.S. federal	$ 100	$ —	$ 12
U.S. state	65	22	77
Total	165	22	89
Deferred:			
U.S. federal	29	223	233
U.S. state	(41)	38	(35)
Total	(12)	261	198
Deferred investment tax credits	2	(3)	(3)
Total income tax expense	$ 155	$ 280	$ 284

We show the components of deferred income taxes, which reflect the effects of the TCJA, at December 31 for SDG&E in the table below:

DEFERRED INCOME TAXES

(Dollars in millions)

	December 31, 2017	December 31, 2016
Deferred income tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 1,472	$ 2,549
Regulatory balancing accounts	113	379
Property taxes	26	42
Other	10	10
Total deferred income tax liabilities	1,621	2,980
Deferred income tax assets:		
Net operating losses	—	—
Tax credits	7	27
Postretirement benefits	43	98
Compensation-related items	5	8
State income taxes	14	—
Accrued expenses not yet deductible	3	7
Other	19	11
Total deferred income tax assets	91	151
Net deferred income tax liability	$ 1,530	$ 2,829

Following is a reconciliation of the changes in unrecognized income tax benefits and the potential effect on our ETR for the years ended December 31:

RECONCILIATION OF UNRECOGNIZED INCOME TAX BENEFITS
(Dollars in millions)

	2017	2016	2015
Balance at January 1	$ 22	$ 20	$ 14
Increase in prior period tax positions	9	—	5
Decrease in prior period tax positions	(11)	—	—
Increase in current period tax positions	—	2	2
Settlements with taxing authorities	(10)	—	(1)
Balance at December 31	$ 10	$ 22	$ 20
Of December 31 balance, amounts related to tax positions that if recognized in future years would			
decrease the effective tax rate(1)	$ (7)	$ (19)	$ (16)
increase the effective tax rate(1)	1	13	11

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

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,		
	2017	2016	2015
Expiration of statutes of limitations on tax assessments	$ —	$ (1)	$ (1)
Potential resolution of audit issues with various U.S. federal, state and local taxing authorities	(6)	(10)	(8)
	$ (6)	$ (11)	$ (9)

Amounts accrued for interest and penalties associated with unrecognized income tax benefits are included in Income Tax Expense on the Statement of Operations. SDG&E accrued negligible amounts of interest expense and penalties at December 31, 2017 and 2016 on the Balance Sheet and recorded negligible amounts of interest income and penalties in 2017, 2016 and 2015 on the Statement of Operations.

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 2013 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 PBOP plans in the year in which the changes occur. Generally, those changes are reported in OCI and as a separate component of shareholders' equity.

The detailed information presented below covers the employee benefit plans of Sempra Energy and its consolidated 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 PBOP plans, 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. 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 $455 million and $430 million at December 31, 2017 and 2016, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Special Termination Benefits Affecting 2017 and 2016

In 2017, certain represented and in 2016, certain nonrepresented employees age 62 or older with 5 years of service or age 55 to 61 with 10 years of service that retired under the Voluntary Retirement Enhancement Program offered in either of those years received an additional postretirement health benefit in the form of a $100,000 Health Reimbursement Account. We treated the benefit obligation attributable to the Health Reimbursement Account as a special termination benefit. This resulted in increases to the recorded liability for PBOP and net periodic benefit cost of $14 million for SDG&E in 2016.

The Voluntary Retirement Enhancement Program resulted in a higher than expected number of retirements in 2017 and 2016. As a result, the total lump sum benefits paid from the SDG&E qualified pension plan in 2016, exceeded the settlement threshold, which triggered settlement accounting. This resulted in a reduction of the recorded pension liability and pension plan assets of $75 million in

2016. This also resulted in settlement charges in net periodic benefit cost of $16 million in 2016. The settlement charges at SDG&E in 2016, were recorded as regulatory assets on the Balance Sheet. Measurement dates of December 31, 2017 and 2016 were used for the respective settlement accounting triggered in each year, as the year-to-date lump sum benefit payments first exceeded the settlement threshold in December of both of those years.

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 2017 and 2016, and a statement of the funded status at December 31, 2017 and 2016:

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

	Pension benefits		Other postretirement benefits	
	2017	2016	2017	2016
CHANGE IN PROJECTED BENEFIT OBLIGATION				
Net obligation at January 1	$ 935	$ 965	$ 190	$ 165
Service cost	29	29	5	5
Interest cost	38	41	8	7
Contributions from plan participants	—	—	7	7
Actuarial loss (gain)	50	7	(9)	6
Benefit payments	(83)	(25)	(16)	(14)
Special termination benefits	—	—	—	14
Settlements	—	(75)	—	—
Transfer of liability from (to) other plans	2	(7)	—	—
Net obligation at December 31	971	935	185	190
CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	714	752	169	161
Actual return on plan assets	120	59	30	13
Employer contributions	22	3	5	2
Contributions from plan participants	—	—	7	7
Benefit payments	(83)	(25)	(16)	(14)
Settlements	—	(75)	—	—
Transfer of assets from other plans	3	—	—	—
Fair value of plan assets at December 31	776	714	195	169
Funded status at December 31	$ (195)	$ (221)	$ 10	$ (21)
Net recorded (liability) asset at December 31	$ (195)	$ (221)	$ 10	$ (21)

Actuarial losses (gains) fluctuate based on changes in assumptions that we describe below in "Assumptions for Pension and Other Postretirement Benefit Plans" and updates to census data. In 2017, 2016 and 2015, the Society of Actuaries released updated mortality improvement projection scales, reflecting changes to projected observed longevity improvements in its mortality tables. We have incorporated these assumptions, adjusted for the SDG&E's actual mortality experience, in our calculations for each of those years. Actuarial losses in pension plans were driven primarily by a decrease in discount rates. Actuarial gains in PBOP plans in 2017 were driven primarily by a reduction in the 2018 expected health care costs.

Net Assets and Liabilities

The assets and liabilities of the pension and PBOP 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. We recognize realized and unrealized investment gains and losses during the current year.

We use 10-percent corridor accounting method. 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 our 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 PBOP 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 PBOP 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	
	2017	2016	2017	2016
Noncurrent assets	$ —	$ —	$ 10	$ —
Current liabilities	(13)	(10)	—	—
Noncurrent liabilities	(182)	(211)	—	(21)
Net recorded (liability) asset	$ (195)	$ (221)	$ 10	$ (21)

Amounts recorded in AOCI at December 31, 2017 and 2016, 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		Other postretirement benefits	
	2017	2016	2017	2016
Net actuarial loss	$ (8)	$ (8)	$ —	$ —

The accumulated benefit obligation for the defined benefit pension plan at December 31, 2017 and 2016 was as follows:

ACCUMULATED BENEFIT OBLIGATION
(Dollars in millions)

	2017	2016
Accumulated benefit obligation	$ 930	$ 904

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)

	2017	2016
Projected benefit obligation	$ 939	$ 902
Accumulated benefit obligation	900	874
Fair value of plan assets	776	714

Net Periodic Benefit Cost

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

NET PERIODIC BENEFIT COST AND AMOUNTS RECOGNIZED IN OCI
(Dollars in millions)

	Pension benefits			Other postretirement benefits		
	2017	2016	2015	2017	2016	2015
NET PERIODIC BENEFIT COST						
Service cost	$ 29	$ 29	$ 29	$ 5	$ 5	$ 7
Interest cost	38	41	39	8	7	8
Expected return on assets	(47)	(49)	(54)	(11)	(12)	(11)
Amortization of:						
Prior service cost	1	1	8	3	3	3
Actuarial loss (gain)	9	10	2	—	(1)	—
Settlement charge	—	16	—	—	—	—
Special termination benefits	—	—	—	—	14	—
Regulatory adjustment	(8)	(45)	(20)	—	(14)	—
Total net periodic benefit cost	22	3	4	5	2	7
CHANGES IN PLAN ASSETS AND BENEFIT OBLIGATIONS RECOGNIZED IN OCI						
Net loss (gain)	2	1	(6)	—	—	—
Amortization of actuarial loss	(1)	(1)	(1)	—	—	—
Total recognized in OCI	1	—	(7)	—	—	—
Total recognized in net periodic benefit cost and OCI	$ 23	$ 3	$ (3)	$ 5	$ 2	$ 7

The estimated net loss for the pension and PBOP plans that will be amortized from AOCI into net periodic benefit cost in 2018 is $1 million for SDG&E. Negligible amount of estimated prior service cost will be similarly amortized in 2018.

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

We develop the discount rate assumptions based on the results of a third party modeling tool that matches each plan's expected 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 that:

- 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 allocation as of the measurement date and the expected returns for those asset types.

We amortize prior service cost using straight line amortization over average future service (or average expected lifetime for plans where participants are substantially inactive employees), which is an alternative method allowed under U.S. 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	
	2017	2016	2017	2016
Discount rate	3.64%	4.08%	3.65%	4.15%
Rate of compensation increase	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00

WEIGHTED-AVERAGE ASSUMPTIONS USED TO DETERMINE NET PERIODIC BENEFIT COST

YEARS ENDED DECEMBER 31	Pension benefits			Other postretirement benefits		
	2017	2016	2015	2017	2016	2015
Discount rate	4.08%	4.35%	4.00%	4.15%	4.50%	4.15%
Expected return on plan assets	7.00	7.00	7.00	6.91	6.90	6.91
Rate of compensation increase	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00

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		
	2017	2016	2015	2017	2016	2015
Health care cost trend rate assumed for next year	7.00%	8.00%	8.10%	5.00%	5.50%	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	2022	2022	2022	2022	2022

A one-percent change in assumed health care cost trend rates would have had the following effects in 2017:

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	$ —
Effect on the health care component of the accumulated other postretirement benefit obligations	3	(2)

Plan Assets

Investment Allocation Strategy for Sempra Energy's Pension Master Trust

Sempra Energy's pension master trust holds the investments for our pension plans and a portion of the investments for our PBOP plans. We maintain additional trusts as we discuss below for certain of the California Utilities' PBOP 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
- 8 percent ultra-long duration government securities
- 5 percent return-seeking credit
- 5 percent real assets

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 asset 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 of Return Assumption

The expected return on assets in our pension and PBOP 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 the SDG&E other postretirement benefit plan are subject to taxation, which impacts the expected after-tax return on assets in the plan.

Concentration of Risk

Plan assets are diversified across global equity and bond markets, and concentration of risk in any one economic, industry, maturity or geographic sector is limited.

Investment Strategy for SDG&E's Other Postretirement Benefit Plans

SDG&E's PBOP 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 trusts. The assets in the Voluntary Employee Beneficiary Association trusts are invested at an allocation similar to the pension master trust, with 74 percent invested in return-seeking and 26 percent invested in risk-mitigating assets. These allocations are 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 investments in the trusts for SDG&E's PBOP plans based on the fair value hierarchy, except for certain investments measured at net asset value (NAV).

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. Where the value is a quoted price in an active market, the investment is classified within Level 1 of the fair value hierarchy. Investments in certain fixed income securities 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 NAV of units owned, which is based on the current fair value of the funds' underlying assets.

Private Equity Funds – These funds consist of investments in private equities that are held by limited partnerships following various strategies, including private equity and corporate finance. These partnerships generally have limited lives of 10 years, after which liquidating distributions will be received. The value is determined based on the NAV of the proportionate share of an ownership interest in partners' capital. Holdings in these types of private equity funds are negligible, as the funds are well past their expected investment term and have distributed the bulk of proceeds from investment sales.

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.

While management believes the valuation methods described above 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 during the periods presented and there were no changes in the valuation techniques used.

SDG&E holds a proportionate share of investment assets in the pension master trust at Sempra Energy Consolidated. 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, 2017

	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Equity securities:			
Domestic	$ 946	$ —	$ 946
International	538	—	538
Registered investment companies	102	—	102
Fixed income securities:			
Domestic government bonds	242	27	269
International government bonds	—	12	12
Domestic corporate bonds	—	338	338
International corporate bonds	—	64	64
Registered investment companies	—	6	6
Other	—	1	1
Total investment assets in the fair value hierarchy	$ 1,828	$ 448	$ 2,276
Investments measured at NAV:			
Common/collective trusts			384
Private equity funds			4
Total investment assets(1)			$ 2,664
SDG&E's proportionate share of investment assets			$ 777
SoCalGas' proportionate share of investment assets			$ 1,697

	Fair value at December 31, 2016		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Equity securities:			
Domestic	$ 884	$ —	$ 884
International	522	—	522
Registered investment companies	127	—	127
Fixed income securities:			
Domestic government bonds	214	32	246
International government bonds	—	9	9
Domestic corporate bonds	—	346	346
International corporate bonds	—	94	94
Registered investment companies	—	14	14
Total investment assets in the fair value hierarchy	$ 1,747	$ 495	$ 2,242
Investments measured at NAV:			
Common/collective trusts			223
Private equity funds			4
Total investment assets(2)			$ 2,469
SDG&E's proportionate share of investment assets			$ 717
SoCalGas' proportionate share of investment assets			$ 1,585

(1) *Excludes cash and cash equivalents of $13 million and accounts payable of $18 million.*

(2) *Excludes cash and cash equivalents of $14 million and accounts payable of $24 million.*

The fair values by asset category of SDG&E's PBOP plan trusts are as follows:

FAIR VALUE MEASUREMENTS – INVESTMENT ASSETS OF OTHER POSTRETIREMENT BENEFIT PLANS

(Dollars in millions)

	Fair value at December 31, 2017		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 46	$ —	$ 46
International	26	—	26
Registered investment companies	52	—	52
Fixed income securities:			
Domestic government bonds	12	1	13
International government bonds	—	1	1
Domestic corporate bonds	—	17	17
International corporate bonds	—	3	3
Registered investment companies	—	17	17
Total investment assets in the fair value hierarchy	136	39	175
Investments measured at NAV – Common/collective trusts			20
Total investment assets(1)			195

(1) *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, 2016		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 41	$ —	$ 41
International	24	—	24
Registered investment companies	46	—	46
Fixed income securities:			
Domestic government bonds	10	1	11
Domestic corporate bonds	—	16	16
International corporate bonds	—	3	3
Registered investment companies	—	17	17
Total investment assets in the fair value hierarchy	121	37	158
Investments measured at NAV – Common/collective trusts			11
Total investment assets(1)			169

(1) *Excludes cash and cash equivalents of $1 million and accounts payable of $1 million held in SDG&E PBOP plan trusts.*

Future Payments

We expect to contribute the following amounts to our pension and PBOP plans in 2018:

EXPECTED CONTRIBUTIONS *(Dollars in millions)*		
Pension plans	$	48
Other postretirement benefit plans		3

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
2018	$ 90	$ 10
2019	76	10
2020	74	10
2021	71	11
2022	68	11
2023-2027	314	52

SAVINGS PLANS

SDG&E offers trusteed savings plans to all employees. Employee participation, employee contributions and employer matching contributions are subject to the provisions of the respective plans, and for employee contributions, limits imposed by governmental authorities.

Employer contributions to the savings plans were as follows:

EMPLOYER CONTRIBUTIONS TO SAVINGS PLANS *(Dollars in millions)*	2017	2016	2015
SDG&E	$ 14	$ 15	$ 17

The market value of Sempra Energy common stock held by the savings plans was $1.1 billion at both December 31, 2017 and 2016.

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 awards
- 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 the three years ended December 31, 2017, Sempra Energy had the following types of equity awards outstanding:

- *Non-Qualified Stock Options:* Options to purchase common stock 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 RSU awards generally vest in Sempra Energy common stock at the end of three-year (for awards granted during or after 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 EPS. The comparative market indices for the awards that vest based on total return to shareholders are the S&P 500 Utilities Index and the S&P 500 Index. We primarily use long-term analyst consensus growth estimates for S&P 500 Utilities Index peer companies to develop our targets for awards that vest based on EPS growth.
  - 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 RSUs may be issued.
  - For awards granted during or after 2014, up to an additional 100 percent of the granted RSUs may be issued if total return to shareholders or EPS growth exceeds target levels.
  - For awards granted in 2015 and 2016, and certain awards granted in 2017, 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 RSUs 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.

  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.
- *Other Performance-Based Restricted Stock Units:* RSUs 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.

- *Service-Based Restricted Stock Units:* RSUs may also be service-based; these generally vest at the end of three-year (for awards granted during or after 2015) or four-year service periods.
- *Restricted Stock Awards:* RSAs are solely service-based and generally vest at the end of four years of service. Accelerated vesting of RSAs may occur upon eligibility for retirement. Holders of RSAs have full voting rights.

For RSA and RSU awards, 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 RSAs and RSUs are reinvested to purchase additional common shares that become subject to the same vesting conditions as the RSAs and RSUs to which the dividends relate.

SHARE-BASED AWARDS AND COMPENSATION EXPENSE

At December 31, 2017, 5,589,925 common 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.

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, RSAs and RSUs 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. Beginning in 2016, we recognize in earnings the tax benefits (or deficiencies) resulting from tax deductions that are in excess of (or less than) tax benefits related to compensation cost recognized for share-based payments. In 2015, $52 million in excess tax benefits was recorded within Sempra Energy's Shareholders' Equity.

Sempra Energy subsidiaries record an expense for the plans to the extent that employees participate in the plans and/or SDG&E is allocated a portion of the Sempra Energy plans' corporate staff costs. Total share-based compensation expense for all of Sempra Energy's share-based awards was comprised as follows:

SHARE-BASED COMPENSATION EXPENSE

(Dollars in millions)

	Years ended December 31,		
	2017	2016	2015
Share-based compensation expense, before income taxes	$ 13	$ 7	$ 8
Income tax benefit	(5)	(3)	(3)
	$ 8	$ 4	$ 5
Capitalized share-based compensation cost	$ 5	$ 4	$ 4
Excess income tax benefit	$ —	$ (7)	$ —

SEMPRA ENERGY NON-QUALIFIED STOCK OPTIONS

We use a Black-Scholes option-pricing 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 Sempra Energy's common 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 stock options were granted in 2017, 2016, or 2015.

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 and foreign exchange rate exposures. 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 natural gas and electricity derivatives, 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 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 and GHG allowances.

We summarize net energy derivative volumes at December 31, 2017 and 2016 as follows:

NET ENERGY DERIVATIVE VOLUMES
(Quantities in millions)

Commodity	Unit of measure	December 31, 2017	December 31, 2016
Natural gas	MMBtu	39	48
Electricity	MWh	3	4
Congestion revenue rights	MWh	59	48

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 Balance Sheet reflects the offsetting of net derivative positions and cash collateral with the same counterparty when a legal right of offset exists. The following table provides the fair values of derivative instruments on the Balance Sheet at December 31, 2017 and

2016, including the amount of cash collateral receivables that were not offset, as the cash collateral was in excess of liability positions.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET

(Dollars in millions)

	December 31, 2017			
	Current assets: Fixed-price contracts and other derivatives	Other assets: Sundry	Current liabilities: Fixed-price contracts and other derivatives	Deferred credits and other liabilities: Fixed-price contracts and other derivatives
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	26	101	(63)	(120)
Associated offsetting commodity contracts	—	(1)	—	1
Associated offsetting cash collateral	—	—	19	4
Net amounts presented on the balance sheet	26	100	(44)	(115)
Additional cash collateral for commodity contracts subject to rate recovery	16	—	—	—
Total(1)	$ 42	$ 100	$ (44)	$ (115)

(1) Normal purchase contracts previously measured at fair value are excluded.

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET

(Dollars in millions)

	December 31, 2016			
	Current assets: Fixed-price contracts and other derivatives	Other assets: Sundry	Current liabilities: Fixed-price contracts and other derivatives	Deferred credits and other liabilities: Fixed-price contracts and other derivatives
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	33	73	(51)	(150)
Associated offsetting commodity contracts	(6)	(1)	6	1
Associated offsetting cash collateral	—	—	3	13
Net amounts presented on the balance sheet	27	72	(42)	(136)
Additional cash collateral for commodity contracts not subject to rate recovery	1	—	—	—
Additional cash collateral for commodity contracts subject to rate recovery	30	—	—	—
Total(1)	$ 58	$ 72	$ (42)	$ (136)

(1) 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 gain (loss) on derivatives recognized in earnings

Years ended December 31,

	Location	2017	2016	2015
Commodity contracts subject to rate recovery	Cost of Electric Fuel and Purchased Power	$ 54	$ (53)	$ (126)

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.

For SDG&E, the total fair value of this group of derivative instruments in a net liability position at December 31, 2017 and 2016 is $1 million and negligible, respectively. At December 31, 2017, if the credit ratings of SDG&E were reduced below investment grade, $1 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 table below, by level within the fair value hierarchy, sets forth our financial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2017 and 2016. 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.

The fair value of commodity derivative assets and liabilities is presented in accordance with our netting policy, as we discuss in Note 7 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, 2017 and 2016 in the tables below include the following:

- Nuclear decommissioning trusts reflect the assets of SDG&E’s NDT, 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. 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 securities are valued based on yields that are currently available for comparable securities of issuers with similar credit ratings (Level 2).

- For commodity contracts, 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 in “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). These investments in marketable securities were negligible at both December 31, 2017 and 2016.

There were no transfers into or out of Level 1, Level 2 or Level 3 for SDG&E during the periods presented.

RECURRING FAIR VALUE MEASURES – SDG&E

(Dollars in millions)

	Fair value at December 31, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts:				
Equity securities	$ 491	$ 5	$ —	$ 496
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	9	—	54

Municipal bonds		—		250		—		250
Other securities		—		217		—		217
Total debt securities		45		476		—		521
Total nuclear decommissioning trusts(1)		536		481		—		1017
Commodity contracts subject to rate recovery		—		—		126		126
Effect of netting and allocation of collateral(2)		11		—		5		16
Total	$	547	$	481	$	131	$	1,159
Liabilities:								
Commodity contracts subject to rate recovery		23		5		154		182
Effect of netting and allocation of collateral(2)		(23)		—		—		(23)
Total	$	—	$	5	$	154	$	159

	Fair value at December 31, 2016							
	Level 1		Level 2		Level 3		Total	
Assets:								
Nuclear decommissioning trusts:								
Equity securities	$	508	$	—	$	—	$	508
Debt securities:								
Debt securities issued by the U.S. Treasury and other								
U.S. government corporations and agencies		36		16		—		52
Municipal bonds		—		206		—		206
Other securities		—		141		—		141
Total debt securities		36		363		—		399
Total nuclear decommissioning trusts(1)		544		363		—		907
Commodity contracts not subject to rate recovery		—		—		—		—
Effect of netting and allocation of collateral(2)		1		—		—		1
Commodity contracts subject to rate recovery		1		2		96		99
Effect of netting and allocation of collateral(2)		25		—		5		30
Total	$	571	$	365	$	101	$	1,037
Liabilities:								
Commodity contracts subject to rate recovery		17		7		170		194
Effect of netting and allocation of collateral(2)		(16)		—		—		(16)
Total	$	1	$	7	$	170	$	178

(1) Excludes cash balances and cash equivalents.

(2) 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.

Level 3 Information

The following table sets forth reconciliations of changes in the fair value of CRRs and long-term, fixed-price electricity positions classified as Level 3 in the fair value hierarchy for SDG&E:

LEVEL 3 RECONCILIATIONS(1)
(Dollars in millions)

	Years ended December 31,					
	2017		2016		2015	
Balance at January 1	$	(74)	$	19	$	107
Realized and unrealized gains (losses)		34		(120)		(134)

Allocated transmission instruments	6	8	12
Settlements	6	19	34
Balance at December 31	$ (28)	$ (74)	$ 19
Change in unrealized gains (losses) relating to			
instruments still held at December 31	$ 30	$ (101)	$ (27)

(1) *Excludes the effect of contractual ability to settle contracts under master netting agreements.*

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 CAISO, an objective source. Annual auction prices are published once a year, typically in the middle of November, and are the basis for valuing CRRs settling in the following year. For the CRRs settling from January 1 to December 31, the auction price inputs, at a given location, are in the following ranges:

CONGESTION REVENUE RIGHTS AUCTION PRICE INPUTS

Settlement year	Price per MWh		
2018	$ (7.25)	to	$ 11.99
2017	(11.88)	to	6.93
2016	(23.81)	to	10.23

The impact associated with discounting is negligible. Because these 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. 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. These inputs range from $22.55 per MWh to $51.01 per MWh at December 31, 2017, and $17.40 per MWh to $56.67 per MWh at December 31, 2016. A significant increase or decrease in market electricity forward prices would result in a significantly higher or lower fair value, respectively. We summarize long-term, fixed-price electricity position volumes in Note 7.

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.

Fair Value of Financial Instruments

The fair values of certain of our financial instruments (cash, accounts and notes receivable, short-term 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, 2017 and 2016:

FAIR VALUE OF FINANCIAL INSTRUMENTS
(Dollars in millions)

	December 31, 2017				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 4,573	$ —	$ 5,073	$ —	$ 5,073

	December 31, 2016				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 4,349	$ —	$ 4,727	$ —	$ 4,727

(1) Before reductions for unamortized discount and debt issuance costs of $44 million and $43 million at December 31, 2017 and 2016, respectively, and excluding capital lease obligations of $1,086 million and $632 million at December 31, 2017 and 2016, respectively.

We determine the fair value of certain long-term amounts due from/to unconsolidated affiliates and long-term debt based on a market approach using quoted market prices for identical or similar securities in thinly-traded markets (Level 2). 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 NDT funds related to SONGS in Note 10.

NOTE 9. PREFERRED STOCK

SDG&E is authorized to issue up to 45 million shares of preferred stock. At December 31, 2017 and 2016, SDG&E had no preferred stock outstanding. The rights, preferences, privileges and restrictions for any new series of preferred stock would be established by each company's board of directors at the time of issuance.

NOTE 10. SAN ONOFRE NUCLEAR GENERATING STATION

SDG&E has 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, after an extended outage beginning in 2012, 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 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 costs. SDG&E's share of operating expenses is included in SDG&E's Statement of Operations.

SONGS STEAM GENERATOR REPLACEMENT PROJECT

As part of the 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 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 recovery of damages. The other SONGS co-owners, SDG&E and the City of Riverside, participated as claimants and respondents.

On March 13, 2017, the Tribunal overseeing the arbitration found MHI liable for breach of contract, subject to a contractual limitation of liability, and rejected claimants' other claims. The Tribunal awarded $118 million in damages to the SONGS co-owners, but determined that MHI was the prevailing party and awarded it 95 percent of its arbitration costs. The damage award is offset by these costs, resulting in a net award of approximately $60 million in favor of the SONGS co-owners. SDG&E's specific allocation of the damage award is $24 million reduced by costs awarded to MHI of approximately $12 million, resulting in a net damage award of $12 million, which was paid by MHI to SDG&E in March 2017. These amounts include certain adjustments to calculations supporting the Tribunal's findings. In accordance with the Amended Settlement Agreement discussed below, SDG&E recorded the proceeds from the MHI arbitration by reducing Operation and Maintenance for previously incurred legal costs of $11 million, and shared the remaining $1 million equally between ratepayers and shareholders.

SETTLEMENT AGREEMENT TO RESOLVE THE CPUC'S ORDER INSTITUTING INVESTIGATION INTO THE SONGS OUTAGE

In November 2012, in response to the outage, the CPUC issued the SONGS OII, which was intended to determine the ultimate recovery of the investment in SONGS and the costs incurred since the commencement of this outage.

In November 2014, the CPUC issued a final decision approving an Amended and Restated Settlement Agreement (Amended Settlement Agreement) in the SONGS OII proceeding executed by SDG&E along with Edison, TURN, ORA and two other intervenors. The Amended Settlement Agreement does not affect ongoing or future proceedings before the NRC, or any litigation or arbitration related to potential future recoveries from third parties (except for the allocation to ratepayers of any recoveries addressed in the final decision) or any proceedings addressing decommissioning activities and costs.

The Amended Settlement Agreement provides for various disallowances, refunds and rate recoveries, including authorizing SDG&E to recover in rates its remaining investment in SONGS, including base plant and construction work in progress, but excluding its investment in the SGRP, 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 (discussed in Note 14) proceeding then in effect (collectively, SONGS return on rate base)

In May 2016, following the filing of petitions for modification by various parties, the CPUC issued a procedural ruling reopening the record of the OII to address the issue of whether the Amended Settlement Agreement is reasonable and in the public interest.

In December 2016, the CPUC issued another procedural ruling directing parties to the SONGS OII to determine whether an agreement could be reached to modify the Amended Settlement Agreement previously approved by the CPUC, to resolve allegations that unreported *ex parte* communications between Edison and the CPUC resulted in an unfair advantage at the time the settlement agreement was negotiated. Pursuant to the December ruling and a subsequent procedural ruling, the parties met to confer, engaged a mediator and held confidential mediation discussions in June, July and August of 2017.

In August 2017, the parties filed status reports providing their recommendations for resolving the OII given their unsuccessful efforts at reaching a settlement through mediation. SDG&E and Edison recommended that the Amended Settlement Agreement, as adopted by the CPUC, should be affirmed and the pending intervenor petitions dismissed. Intervening parties recommended various alternative courses of action, including modifying the Amended Settlement Agreement or rejecting it in favor of litigation. In October 2017, the CPUC issued a ruling establishing a process to bring the proceeding to a conclusion. This ruling establishes a status conference and includes a preliminary schedule for additional testimony, hearings and briefings.

On January 30, 2018, SDG&E, Edison, ORA, TURN and other intervenors entered into a settlement agreement (Revised Settlement Agreement). On the same date, a Joint Motion for Adoption of the Settlement Agreement was filed with the CPUC. If approved by the CPUC, the Revised Settlement Agreement will resolve all issues under consideration in the SONGS OII and will modify the Amended Settlement Agreement approved by the CPUC in November 2014. The Revised Settlement Agreement was the result of multiple mediation sessions in 2017 and January 2018 and was signed following a settlement conference in the SONGS OII, as required under CPUC rules. On February 1, 2018, the parties filed a motion to stay the proceedings in the OII pending the CPUC's consideration of the Revised Settlement Agreement. On February 6, 2018, the CPUC granted the parties' motion to stay the proceedings and established a tentative procedural schedule with public participation hearings in April and July, evidentiary hearings in April and May, and briefing in June of 2018.

The Revised Settlement Agreement is subject to CPUC approval. The parties to the Revised Settlement Agreement have agreed to exercise their best efforts to obtain CPUC approval. In the event that the CPUC fails to approve the Revised Settlement Agreement, the proceeding will remain open and subject to previous rulings in the SONGS OII, and the Amended Settlement Agreement will remain in effect, unless it is modified or set aside by the CPUC as a result of the OII proceeding.

In connection with the Revised Settlement Agreement, and in exchange for the release of certain SONGS-related claims, SDG&E and Edison entered into the Utility Shareholder Agreement, described below, in which Edison has agreed to pay for the amounts that SDG&E would have received in rates under the Amended Settlement Agreement but will not receive upon implementation of the Revised Settlement Agreement. The Utility Shareholder Agreement is not subject to the approval of the CPUC. However, it is not effective unless and until the CPUC approves the Revised Settlement Agreement.

The timing of a ruling by the CPUC on the Joint Motion for Adoption of the Revised Settlement Agreement is unclear. There is no assurance that the Revised Settlement Agreement will be adopted or that the Amended Settlement Agreement will not be modified or set aside as a result of the OII proceeding, which could result in a substantial reduction in our expected recovery or in payments to customers. These outcomes could have a material adverse effect on SDG&E's results of operations, financial condition and cash flows.

Disallowances, Refunds and Recoveries

If the Revised Settlement Agreement is approved by the CPUC, SDG&E and Edison will cease rate recovery of SONGS costs as authorized under the Amended Settlement Agreement as of the date their combined remaining SONGS regulatory assets equal $775 million (the Cessation Date). Currently, the estimated Cessation Date is December 19, 2017. The Cessation Date is partly dependent on the outcome of Edison's pending request to the CPUC, in a separate proceeding, for approval to apply certain proceeds received from the DOE to reduce Edison's SONGS regulatory asset. If this request is rejected by the CPUC, then the estimated Cessation Date will be April 21, 2018. In either case, under the Utility Shareholder Agreement, Edison is obligated to pay SDG&E the full amount of SDG&E's revenue requirement not recovered from ratepayers, as described below. SDG&E and Edison will refund to customers SONGS-related amounts recovered in rates after the Cessation Date.

In the event that the CPUC takes an action that has the effect of invalidating the Utility Shareholder Agreement, SDG&E may, in its discretion, withdraw from the Revised Settlement Agreement, in which case Edison shall remain a party to the Revised Settlement Agreement, but the Revised Settlement Agreement shall be terminated as to SDG&E. In such a scenario, SDG&E would return to its litigation position before the CPUC in the SONGS OII that existed prior to the Revised Settlement Agreement.

Pursuant to the CPUC's rules, no settlement becomes binding unless the CPUC approves the settlement based on a finding that it is reasonable in light of the whole record, consistent with law, and in the public interest. The CPUC has discretion to approve or disapprove a settlement, or to condition its approval on changes to the settlement, which the parties may accept or reject, negotiating in good faith to seek a resolution acceptable to all parties. CPUC rules do not provide for any fixed time period for the CPUC to act on proposed settlements.

Utility Shareholder Agreement

On January 10, 2018, SDG&E and Edison entered into the Utility Shareholder Agreement. Under the terms of the Utility Shareholder Agreement, Edison has an obligation to compensate SDG&E for the revenue requirement amounts that SDG&E will no longer recover because of the Revised Settlement Agreement. In exchange for Edison's reimbursement, the parties will mutually release each other from the "SONGS Issues," a defined term that consists of 18 broad categories. The effect of the agreement is that SDG&E will release Edison from any and all claims that SDG&E had or could have asserted related to the steam generator replacement failure and its aftermath. The Utility Shareholder Agreement becomes effective only upon CPUC approval of the Revised Settlement Agreement. Edison's payment obligation commences 30 days after the first fiscal quarter in which the CPUC approves the Revised Settlement Agreement, and amounts are due to SDG&E quarterly thereafter until April 2022, which approximates the amounts and timing of amounts of what would have been SDG&E's recoveries from ratepayers contemplated under the Amended Settlement Agreement.

Accounting and Financial Impacts

As a result of the Revised Settlement Agreement by the settling parties and the Utility Shareholder Agreement, SDG&E recorded a receivable from Edison totaling $152 million, $32 million classified as current and $120 million classified as noncurrent, as of December 31, 2017. This receivable reflects amounts Edison is obligated to pay to SDG&E in lieu of amounts SDG&E would have collected from ratepayers associated with the SONGS regulatory asset, which SDG&E believes is now no longer probable of recovery.

Assuming the Revised Settlement Agreement is approved, SDG&E does not expect that implementation of the Revised Settlement Agreement in combination with the Utility Shareholder Agreement will have a material adverse impact on either company. However, until the CPUC approves the Revised Settlement Agreement as proposed, there can be no assurance that the SONGS OII proceeding will conclude as contemplated by SDG&E in accordance with the Revised Settlement Agreement and the Utility Shareholder Agreement, or that the CPUC will not order refunds to customers above those contemplated by the Amended Settlement Agreement, or take other action that may be adverse to SDG&E. Such alternative outcomes could have a material adverse effect on SDG&E's results of operations, financial condition and cash flows.

SETTLEMENT WITH NEIL

As we discuss below, 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, SDG&E's share of which was $80 million. Pursuant to the terms of the 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 the ERRA.

NUCLEAR DECOMMISSIONING AND FUNDING

As a result of Edison's decision to permanently retire SONGS Units 2 and 3, Edison began the decommissioning phase of the plant. Decommissioning of Unit 1, removed from service in 1992, is largely complete. The remaining work for Unit 1 will be done once Units 2 and 3 are dismantled. In December 2016, Edison announced that, following a 10-month competitive bid process, it had contracted with a joint venture of AECOM and EnergySolutions (known as SONGS Decommissioning Solutions) as the general contractor to complete the dismantlement of SONGS. The majority of the dismantlement work is expected to take 10 years. SDG&E is responsible for approximately 20 percent of the total contract price.

In accordance with state and federal requirements and regulations, SDG&E has assets held in the NDT to fund its share of decommissioning costs for SONGS Units 1, 2 and 3. The amounts collected in rates for SONGS' decommissioning are invested in the NDT, which is comprised of externally managed trust funds. Amounts held by the NDT are invested in accordance with CPUC regulations. The NDT assets are presented on the SDG&E Balance Sheet at fair value with the offsetting credits recorded in noncurrent Regulatory Liabilities.

In April 2016, the CPUC adopted a decision approving a total decommissioning cost estimate for SONGS Units 2 and 3 of $4.4 billion (in 2014 dollars), of which SDG&E's share is $899 million. 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. SDG&E has received authorization from the CPUC to access NDT funds of up to $362 million for 2013 through 2018 (2018 forecasted) SONGS decommissioning costs. This includes up to $60 million authorized by the CPUC in January 2018 to be withdrawn from the NDT for forecasted 2018 SONGS Units 2 and 3 costs as decommissioning costs are incurred.

In December 2016, the IRS and the U.S. Department of the Treasury issued proposed regulations that clarify the definition of "nuclear decommissioning costs," which are costs that may be paid for or reimbursed from a qualified trust fund. The proposed regulations state that costs related to the construction and maintenance of independent spent fuel management installations are included in the definition of "nuclear decommissioning costs." The proposed regulations will be effective prospectively once they are finalized; however, the IRS has stated that it will not challenge taxpayer positions consistent with the proposed regulations for taxable years ending on or after the date the proposed regulations were issued. SDG&E is awaiting the adoption of, or additional refinement to, the proposed regulations before determining whether the proposed regulations will allow SDG&E to access the NDT funds for reimbursement or payment of the spent fuel management costs that were or will be incurred in 2016 and subsequent years. Further clarification of the proposed regulations could enable SDG&E to access the NDT to recover spent fuel management costs before Edison reaches final settlement with the DOE regarding the DOE's reimbursement of these costs. Historically, the DOE's reimbursements of spent fuel storage costs have not resulted in timely or complete recovery of these costs. We discuss the DOE's responsibility for spent nuclear fuel below. The IRS held public hearings on the proposed regulations in October 2017. It is unclear when clarification of the proposed regulations might be provided or when the proposed regulations will be finalized.

Nuclear Decommissioning Trusts

The amounts collected in rates for SONGS' decommissioning are invested in the NDT, which is comprised of externally managed trust funds. Amounts held by the trusts are invested in accordance with CPUC regulations. These trusts are shown on the SDG&E Balance Sheet at fair value with the offsetting credits recorded in noncurrent Regulatory Liabilities.

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 10.

NUCLEAR DECOMMISSIONING TRUSTS
(Dollars in millions)

	Cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value
At December 31, 2017:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies(1)	$ 54	$ —	$ —	$ 54
Municipal bonds(1)	245	7	(2)	250
Other securities(2)	215	3	(1)	217
Total debt securities	514	10	(3)	521
Equity securities	171	326	(1)	496
Cash and cash equivalents	16	—	—	16
Total	$ 701	$ 336	$ (4)	$ 1,033
At December 31, 2016:				

Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	$ 52	$ —	$ —	$ 52
Municipal bonds	203	4	(1)	206
Other securities	141	2	(2)	141
Total debt securities	396	6	(3)	399
Equity securities	143	366	(1)	508
Cash and cash equivalents	119	—	—	119
Total	$ 658	$ 372	$ (4)	$ 1,026

(1) *Maturity dates are 2018-2048.*

(2) *Maturity dates are 2018-2064.*

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,		
	2017	2016	2015
Proceeds from sales(1)	$ 1,314	$ 1,134	$ 577
Gross realized gains	157	111	29
Gross realized losses	(14)	(29)	(15)

(1) *Excludes securities that are held to maturity.*

Net unrealized gains and losses, as well as realized gains and losses that are reinvested in the NDT, are included in noncurrent Regulatory Liabilities on SDG&E’s Balance Sheet. We determine the cost of securities in the trusts on the basis of specific identification. In 2017 and 2016, sale and purchase activities in our NDT increased significantly compared to 2015 as a result of continuing changes to our asset allocations initiated in the fourth quarter of 2016 to reduce our equity volatility, lower our duration risk, and increase exposure to municipal bonds and intermediate credit. This shift in our asset mix is intended to reduce the overall risk profile of the NDT in anticipation of significant cash withdrawals over the next 10 years to fund the SONGS decommissioning.

ASSET RETIREMENT OBLIGATION AND SPENT NUCLEAR FUEL

SDG&E’s asset retirement obligation related to decommissioning costs for the SONGS units was $607 million at December 31, 2017. 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, 2017 for Unit 1 is based on a cost study prepared in 2016 that is pending CPUC approval. The asset retirement obligation at December 31, 2017 for Units 2 and 3 is based on a CPUC-approved cost study prepared in 2014 that reflects the acceleration of the start of decommissioning of these units as a result of the early closure of the plant. SDG&E’s share of total decommissioning costs in 2017 dollars is approximately $1 billion.

U.S. Department of Energy Nuclear Fuel Disposal

Spent nuclear fuel from SONGS is currently stored on-site in an ISFSI licensed by the NRC or temporarily in spent fuel pools. In October 2015, the CCC approved Edison's application for the proposed expansion of the ISFSI at SONGS. The ISFSI expansion began construction in 2016 and is expected to be fully loaded with spent fuel by 2019 and to operate until 2049, when it is assumed that the DOE will have taken custody of all the SONGS spent fuel. The ISFSI would then be decommissioned, and the site restored to its original environmental state. Until then, SONGS owners are responsible for interim storage of spent nuclear fuel at SONGS.

The Nuclear Waste Policy Act of 1982 made the DOE responsible for accepting, transporting, and disposing 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 continue to support Edison in its pursuit of claims on behalf of the SONGS co-owners against the DOE for its failure to timely accept the spent nuclear fuel. In April 2016, Edison executed a spent fuel settlement agreement with the DOE for $162 million covering damages incurred from 2006 through 2013. In May 2016, Edison refunded SDG&E $32 million for its respective share of the damage award paid. In applying this refund, SDG&E recorded a $23 million reduction to the SONGS regulatory asset, an $8 million reduction of its nuclear decommissioning balancing account and a $1 million reduction in its SONGS O&M cost balancing account.

In September 2016, Edison filed claims with the DOE for $56 million in spent fuel management costs incurred in 2014 and 2015 on behalf of the SONGS co-owners under the terms of the 2016 spent fuel settlement agreement. In February 2017, the DOE reduced the request to approximately $43 million primarily due to reductions to the claimed fuel canister costs. SDG&E received its $9 million respective share of the claim from Edison in May 2017 and recorded the proceeds in balancing accounts or as reductions to regulatory assets for the benefit of ratepayers.

In October 2017, Edison filed claims with the DOE for $58 million in spent fuel management costs incurred in 2016 on behalf of the SONGS co-owners under the terms of the 2016 spent fuel settlement agreement. SDG&E's respective share of the claim is $12 million. It is unclear whether the claim will be resolved through settlement or arbitration, when resolution is expected, and whether Edison will receive an award for the full claim amount.

The 2016 spent fuel settlement agreement governs the submission of claims for costs incurred through December 31, 2016. It is unclear whether Edison will enter into a new settlement with the DOE or pursue litigation claims for spent fuel management costs incurred on or after January 1, 2017.

NUCLEAR INSURANCE

Edison requested and was granted approval in January 2018 by the NRC to reduce the nuclear liability and property damage insurance requirement, as described below. However, these changes in SONGS nuclear insurance levels require approval from all SONGS owners, which has not yet been obtained. We expect a decision in the first quarter of 2018.

SDG&E and the other owners of SONGS have insurance to cover claims from nuclear liability incidents arising at SONGS. Currently, this insurance provides $450 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 billion of SFP. If a nuclear liability loss occurring at any U.S. licensed/commercial reactor exceeds the $450 million insurance limit, all nuclear reactor owners could be required to contribute to the SFP. In such case, SDG&E's contribution would be up to $50.9 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, SDG&E could be subject to an additional assessment. Effective January 5, 2018, the NRC approved Edison's request to reduce the nuclear liability insurance requirement from $450 million to $100 million and withdraw from participation in the SFP for SONGS.

The SONGS owners, including SDG&E, also maintain nuclear property damage insurance that exceeds the minimum federal requirements of $1.06 billion. This insurance coverage is provided through 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 $10.4 million of retrospective premiums based on overall member claims. All of SONGS' insurance claims arising out of the failures of the MHI replacement steam generators have been settled with NEIL, as we discuss above. Effective January 10, 2018, the NRC approved Edison's request to reduce its property damage insurance requirement for SONGS from $1.06 billion to $50 million.

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

NOTE 11. REGULATORY MATTERS

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)

(Dollars in millions)		
	December 31,	
	2017	2016
Fixed-price contracts and other derivatives	$ 96	$ 141
Costs related to SONGS plant closure(1)	—	183
Costs related to wildfire litigation	—	353
Deferred income taxes (refundable) recoverable in rates	(281)	1,014
Pension and other postretirement benefit plan obligations	153	210
Removal obligations	(1,846)	(1,725)
Unamortized loss on reacquired debt	9	12
Environmental costs	29	48
Legacy meters(1)	—	16
Sunrise Powerlink fire mitigation	119	118
Regulatory balancing accounts(2)		
Commodity – electric	82	35
Gas transportation	22	61
Safety and reliability	48	20
Public purpose programs	(70)	(106)
Other balancing accounts	233	249
Other regulatory liabilities	(70)	(2)
Total SDG&E	(1,476)	627

(1) *Regulatory assets earning a rate of return.*

(2) *At December 31, 2017, the noncurrent portion of regulatory balancing accounts – net undercollected for SDG&E was $63 million.*

In the table 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. We discuss these fixed-price contracts and other derivatives further in Note 7.
- Regulatory assets arising from the 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. Pursuant to the Revised Settlement Agreement, rate recovery of SONGS costs remaining as a regulatory asset as of the Cessation Date will cease. Under the Utility Shareholder Agreement, SDG&E recorded a receivable from Edison in lieu of amounts SDG&E would have collected from ratepayers. We discuss these matters further in Note 10.
- Regulatory assets for CPUC-related costs for wildfire litigation are costs in excess of liability insurance coverage and amounts recovered from third parties. In December 2017, the CPUC issued a final decision, denying SDG&E's request to recover these costs. In 2017, SDG&E wrote off the wildfire regulatory asset resulting in a charge of $351 million, as we discuss in Note 12 in "SDG&E – 2007 Wildfire Litigation and Net Cost Recovery Status."
- Deferred income taxes refundable/recoverable in rates are based on current regulatory ratemaking and income tax laws. SDG&E expects to refund/recover net regulatory liabilities/assets related to deferred income taxes over the lives of the assets that give rise to the related accumulated deferred income tax balances. Regulatory assets include certain income tax benefits associated with

flow-through repair allowance deductions, which we discuss further below. In 2017, as a result of the TCJA, lowering the U.S. statutory corporate federal income tax from 35 percent to 21 percent resulted in excess deferred income tax balances that we expect to refund to ratepayers in accordance with the IRS normalization rules and as determined by the CPUC and the FERC. We discuss the TCJA and the impacts on SDG&E in more detail in Note 4.

- Regulatory assets/liabilities related to pension and other postretirement benefit plan obligations are offset by corresponding liabilities/assets and are being recovered in rates as the plans are funded.
- Regulatory liabilities from removal obligations represent cumulative amounts collected in rates for future asset removal costs.
- 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 1 year to 10 years.
- 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. We discuss environmental issues further in Note 12.
- The regulatory asset related to the legacy meters removed from service and replaced under the Smart Meter Program is their undepreciated value. SDG&E has fully recovered this asset 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 52-year period. We discuss the trust further in Note 12.
- The regulatory asset related to workers' compensation represents accrued costs for future claims that will be recovered from customers in future rates as expenditures are made.
- Over- and undercollected regulatory balancing accounts reflect the difference between customer billings and recorded or CPUC-authorized costs, including commodity costs. Depreciation and return on rate base may also be included in certain accounts. Amounts in the balancing accounts are recoverable (receivable) or refundable (payable) in future rates, subject to CPUC approval. Absent balancing account treatment, variations in covered costs, such as the cost of fuel supply and certain O&M costs, from amounts approved by the CPUC would increase volatility in utility earnings. Balancing account treatment eliminates the volatility in earnings that would otherwise result from variances in the covered costs compared to the authorized amounts.

Amortization expense on regulatory assets for the years ended December 31, 2017, 2016 and 2015 was $49 million, $63 million and $60 million, respectively, at SDG&E.

CALIFORNIA UTILITIES MATTERS

CPUC General Rate Case

The CPUC uses a GRC proceeding to set sufficient rates to allow SDG&E to recover their reasonable cost of O&M and to provide the opportunity to realize their authorized rates of return on their investment.

2019 General Rate Case

On October 6, 2017, SDG&E filed its 2019 GRC application requesting CPUC approval of test year revenue requirement for 2019 and attrition year adjustments for 2020 through 2022. SDG&E requested revenue requirement for 2019 of $2.199 billion, which is an increase of $217 million over their 2018 revenue requirement (the 2018 revenue requirement reflect the impact of updated testimony filed in January 2018). SDG&E is proposing post-test year revenue requirement changes using various adjustment factors which are estimated to result in annual increases of approximately 5 percent to 7 percent at SDG&E. The 2019 GRC application does not reflect the impact of the TCJA, which we discuss in Note 4. In April 2018, SDG&E will be updating its application to reflect the impact of the TCJA. SDG&E is assessing the impact of the new tax law on its 2018 operations and have a tax tracking mechanism for net tax benefits that will flow to ratepayers. SDG&E intends to work with the CPUC to determine the mechanism for passing on the savings to ratepayers.

As part of the 2019 GRC, the CPUC will review SDG&E's interim accountability report, which compares the authorized and actual spending for certain safety-related activities for 2014 through 2016. In June 2017, SDG&E filed its first interim accountability report comparing authorized and actual spending in 2014 and 2015 for certain safety-related activities. Similar data for 2016 was provided with the 2019 GRC filings in a second interim accountability report. The stated purpose of the interim accountability reports is to provide data and metrics for key safety and risk mitigation areas that will be considered in the 2019 GRC.

The results of the rate case may materially and adversely differ from what is contained in the GRC applications.

Risk Assessment Mitigation Phase Reporting and Impact on the 2019 GRC Filings

In December 2014, the CPUC issued a decision incorporating a risk-based decision-making framework into all future GRC application filings for major natural gas and electric utilities in California. The framework is intended to assist in assessing safety risks and the utilities' plans to help ensure that such risks are adequately addressed. In advance of filing SDG&E's 2019 GRC application discussed above, two proceedings occurred: the Safety Model Assessment Proceeding and the RAMP. In the Safety Model Assessment Proceeding, SDG&E demonstrated the models used to prioritize and mitigate risks in order for the CPUC to establish guidelines and standards for these models.

In November 2016, as part of the new framework, SDG&E filed its first RAMP report presenting a comprehensive assessment of its key safety risks and proposed activities for mitigating such risks. The report details these key safety risks, which include critical operational issues such as natural gas pipeline safety and wildfire safety, and addresses their classification, scoring, mitigation, alternatives, safety culture, quantitative analysis, data collection and lessons learned.

In March 2017, the CPUC's Safety and Enforcement Division issued its evaluation report providing generally favorable feedback on SDGE's RAMP report, but recommending more detailed analysis of the risks presented in the report. The new GRC framework does not require the CPUC to adopt the RAMP report. However, SDG&E included funding requests in their 2019 GRC filing for proposed projects or activities outlined in their RAMP report.

Senate Bill 549. In September 2017, SB 549 was signed into law, requiring that SDG&E (as an electric and gas corporation) annually notify the CPUC when revenue authorized by the CPUC for maintenance, safety or reliability is redirected to other purposes. This requirement is effective beginning January 1, 2018. The form of this reporting is not yet defined by the CPUC, though it could be incorporated into an ongoing proceeding or report otherwise required to be submitted to the CPUC.

2016 General Rate Case

In June 2016, the CPUC issued a final decision in the 2016 GRC. The 2016 GRC FD adopted a 2016 revenue requirement of $1.791 billion for SDG&E. The 2016 GRC FD was effective retroactive to January 1, 2016, and SDG&E recorded the retroactive impacts in the second quarter of 2016. The 2016 GRC FD also required certain refunds to be paid to customers and establishes a two-way income tax expense memorandum account, each discussed below.

The 2016 GRC FD also adopted subsequent annual escalation of the adopted revenue requirements by 3.5 percent for years 2017 and 2018 and continuation of the Z-Factor mechanism for qualifying cost recovery. The Z-Factor mechanism allows SDG&E to seek cost recovery of significant cost increases, under certain unforeseen circumstances, incurred between GRC filings, subject to a $5 million deductible per event. Also, the 2016 GRC FD denied a separate request for a four-year GRC period and instead adopted a three-year GRC period (through 2018).

The 2016 GRC FD results in certain accounting impacts associated with flow-through income tax repairs deductions. In general, the 2016 GRC FD considers that the income tax benefits obtained from income tax repairs deductions exceeded amounts forecasted by SDG&E 2011 to 2015, and that they were attributed to shareholders during that time. The 2016 GRC FD reallocated the economic benefit of this tax deduction forecasting difference to ratepayers. Accordingly, revenues corresponding to income tax repair deductions that exceeded forecasted amounts relating to 2015, which were tracked in memorandum accounts, were ordered to be refunded to customers. The 2015 estimated amounts in the memorandum accounts totaled $37 million for SDG&E. Pursuant to this refund requirement, SDG&E recorded regulatory liabilities for these amounts, resulting in after-tax charges to earnings of $22 million, in the second quarter of 2016 (summarized below). In addition, the 2016 GRC FD reduced rate base by $55 million at SDG&E. The corresponding reductions in the 2016 revenue requirement was $7 million at SDG&E (which reductions are included in the adopted 2016 revenue requirement amounts described above). The rate base reductions reallocate to ratepayers the economic benefits associated with tax repair deductions that were previously provided to the shareholders for the period of 2011-2014 for SDG&E. The rate base reductions did not result in an impairment of any of our reported assets, but have impacted our revenues and earnings prospectively.

The 2016 GRC FD also requires us to notify the CPUC if the 2012-2015 repairs deductions estimated in this GRC are different from the actual repairs deductions for SDG&E. SDG&E recorded regulatory liabilities of $15 million related to 2012-2014, resulting in after-tax charges to earnings for these differences of $9 million in the second quarter of 2016 for SDG&E (summarized below). In the third quarter of 2016, SDG&E completed its 2015 calendar year tax returns, and final tax deductions associated with tax repair benefits to be refunded to ratepayers associated with the 2015 memo account were lower than the amounts estimated in 2015. Accordingly, the amounts to be refunded decreased by $5 million for SDG&E. In October 2016, SDG&E filed a regulatory account update with the CPUC to reflect their final total 2015 repair allowance deductions of $32 million. After recording the related income tax effect and corresponding regulatory revenue adjustments for income tax purposes, there was no net impact to earnings from the adjustments to the 2015 tax repairs deductions recorded in the third quarter of 2016. Accordingly, the earnings impacts in the table below are also the earnings impacts for the year ended December 31, 2016.

Following is a summary of the 2016 earnings impacts from the 2016 GRC FD:

EARNINGS IMPACTS IN 2016 FROM THE 2016 GRC FD
(Dollars in millions)

	Pretax earnings (charge)	After-tax earnings (charge)
Adjustments to revenue related to tax repairs deductions:		
2015 memorandum account balance	$ (37)	$ (22)
True-up of 2012-2014 estimates to actuals	(15)	(9)
Total	$ (52)	$ (31)

As discussed above, the 2016 GRC FD required the establishment of two-way income tax expense memorandum accounts to track any revenue variances resulting from certain differences between the income tax expense forecasted in the GRC and the income tax expense incurred by SDG&E from 2016 through 2018. The variances to be tracked include tax expense differences relating to:

- net revenue changes;
- mandatory tax law, tax accounting, tax procedural, or tax policy changes; and
- elective tax law, tax accounting, tax procedural, or tax policy changes.

Starting in the second quarter of 2016, SDG&E began tracking the differences in the income tax expense forecasted in the GRC proceedings and the income tax expense incurred. At December 31, 2017, the recorded regulatory liability associated with these tracked amounts totaled $65 million for SDG&E. The recorded liability is primarily related to lower income tax expense incurred than was forecasted in the GRC relating to tax repairs deductions, self-developed software deductions and certain book-over-tax depreciation. We are currently assessing the impact of federal tax reform on 2018 operations and will track such impacts in the tracking accounts. The tracking accounts will remain open, and we expect they will be reviewed in the 2019 GRC proceedings. Federal tax reform, which we discuss in Note 4, could result in significant amounts recorded in these tracking accounts beginning in 2018.

CPUC Cost of Capital

In July 2017, the CPUC issued a final decision adopting, with certain modifications, the joint petition filed in February 2017 by SDG&E, SoCalGas, PG&E and Edison, along with ORA and TURN. The final decision provides a two-year extension for each of the utilities to file its next respective cost of capital application, extending the filing date to April 2019 for a 2020 test year. The final decision also reduces the ROE for SDG&E from 10.30 percent to 10.20 percent, effective from January 1, 2018 through December 31, 2019. SDG&E's ratemaking capital structure will remain at current levels until modified, if at all, by a future cost of capital decision by the CPUC. In September 2017, SDG&E filed advice letter to update their cost of capital for the actual cost of long-term debt through August 2017 and forecasted cost through 2018. SDG&E did not file for changes to preferred stock costs, because no issuances of preferred stock through 2018 are anticipated.

In October 2017, the CPUC approved the embedded cost of debt presented in the filed advice letters, resulting in a revised return on rate base for SDG&E from 7.79 percent to 7.55 percent, effective January 1, 2018, as depicted in the table below:

AUTHORIZED COST OF CAPITAL AND RATE STRUCTURE – CPUC

	Authorized weighting	Return on rate base	Weighted return on rate base
Long-Term Debt	45.25 %	4.59 %	2.08 %
Preferred Stock	2.75	6.22	0.17
Common Equity	52.00	10.20	5.30
	100.00 %		**7.55 %**

As a result of the updates included in the filed advice letter, the impact of the changes to the embedded cost of debt and return on rate base is summarized below:

IMPACT OF THE EMBEDDED COST OF DEBT

	Cost of debt	Return on rate base
Current	5.00%	7.79%
Authorized, effective January 1, 2018	4.59%	7.55%
Differences	(41) bps	(24) bps

The automatic CCM will be in effect to adjust 2019 cost of capital, if necessary. Unless changed by the operation of the CCM, the updated costs of long-term debt and the new ROEs will remain in effect through December 31, 2019. The cost of capital changes will also apply to capital expenditures in 2018 and 2019 for incremental projects not funded through the GRC revenue requirement.

SDG&E MATTERS

FERC Rate Matters and Cost of Capital

SDG&E files separately with the FERC for its authorized ROE on FERC-regulated electric transmission operations and assets.

SDG&E's current estimated FERC return on rate base under the TO4 formula rate request filing is 7.51 percent based on its capital structure as follows:

SDG&E COST OF CAPITAL AND RATE STRUCTURE – FERC

	Weighting	Return on rate base	Weighted return on rate base
Long-Term Debt	43.44%	4.21%	1.83%
Common Equity	56.56	10.05	5.68
	100%		**7.51%**

SDG&E expects to file its TO5 formula rate request with the FERC by June 2018, to be effective January 1, 2019.

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, 2017, loss contingency accruals for legal matters, including associated legal fees, that are probable and estimable were $3 million for SDG&E. We discuss our policy regarding accrual of legal fees in Note 1.

SDG&E

2007 Wildfire Litigation and Net Cost Recovery Status

SDG&E has resolved all litigation associated with three wildfires that occurred in October 2007, except one appeal that remains pending after judgment in the trial court. SDG&E does 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. SDG&E maintains reserves for the wildfire litigation and adjusts these reserves as information becomes available and amounts are estimable.

SDG&E recorded regulatory assets for CPUC-related costs incurred to resolve wildfire claims in excess of its liability insurance coverage and the amounts recovered from third parties. In September 2015, SDG&E filed an application with the CPUC seeking authority to recover these CPUC-related costs in rates over a six- to ten-year period. The requested amount was the net estimated CPUC-related cost incurred by SDG&E after deductions for insurance reimbursement and third-party settlement recoveries, and reflected a voluntary 10-percent shareholder contribution applied to the net regulatory asset for wildfire costs. In August 2017, the CPUC issued a proposed decision denying SDG&E's request to recover the 2007 wildfire costs submitted in our application. In consideration of the proposed decision (including the actions not taken through the October 26, 2017 CPUC meeting), we concluded that the wildfire regulatory asset no longer met the probability threshold for recovery required by U.S. GAAP. Accordingly, SDG&E wrote off the wildfire regulatory asset, resulting in a charge of $351 million ($208 million after-tax) in the third quarter of 2017, in Write-off of Wildfire Regulatory Asset on the Statement of Operations. In December 2017, the CPUC issued a final decision upholding the proposed decision. SDG&E will continue to vigorously pursue recovery of these costs, which were incurred through settling claims brought under the doctrine of inverse condemnation. SDG&E applied to the CPUC for rehearing of its decision on January 2, 2018. The CPUC may grant a rehearing, modify its decision, or deny the request and affirm its original decision. We will appeal the decision with the California Courts of Appeal seeking to reverse the CPUC's decision, if necessary.

Concluded Matter

SDG&E participated as a claimant and respondent in an arbitration proceeding initiated by Edison in October 2013 against MHI seeking damages stemming from the failure of the MHI replacement steam generators at the SONGS nuclear power plant. In March 2017, the Tribunal found MHI liable for breach of contract, subject to a contractual limitation of liability, but determined that MHI was the prevailing party and awarded it 95 percent of its arbitration costs. We discuss this arbitration and decision further in Note 10.

CONTRACTUAL COMMITMENTS

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 2017, we had no payments under natural gas contracts.

Purchased-Power Contracts

For 2018, SDG&E expects to meet its customer power requirements from the following resource types:

- Long-term contracts: 43 percent (of which 37 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: 1 percent

At December 31, 2017, the future estimated payments under long-term purchased-power contracts are as follows:

FUTURE ESTIMATED PAYMENTS – PURCHASED-POWER CONTRACTS *(Dollars in millions)*	
2018	$ 577
2019	571
2020	510
2021	510
2022	496
Thereafter	5,457
Total estimated payments(1)(2)	$ 8,121

(1) *Excludes purchase agreements accounted for as capital leases .*

(2) *Includes $5.4 billion of expected payments under purchase agreements accounted for as operating leases at SDG&E, comprising renewable energy PPAs for which there are no future minimum operating lease payments.*

Payments on these contracts represent capacity charges and minimum energy and transmission purchases that exceed the minimum commitment. SDG&E is required to pay additional amounts for actual purchases of energy that exceed the minimum energy commitments. Total payments under purchased-power contracts were as follows:

PAYMENTS UNDER PURCHASED-POWER CONTRACTS *(Dollars in millions)*			
	Years ended December 31,		
	2017	2016	2015
SDG&E	$ 781	$ 752	$ 715

Operating Leases

We have operating leases on real and personal property expiring at various dates from 2018 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.

The California Utilities have operating lease agreements for future acquisitions of fleet vehicles with an aggregate maximum lease limit of $250 million, $133 million of which has been utilized as of December 31, 2017.

Rent expense for operating leases was as follows:

RENT EXPENSE – OPERATING LEASES *(Dollars in millions)*			
	Years ended December 31,		
	2017	2016	2015
SDG&E	$ 28	$ 28	$ 27

At December 31, 2017, the rental commitments payable in future years under all noncancelable operating leases, including estimated payments, are as follows:

FUTURE RENTAL PAYMENTS – OPERATING LEASES
(Dollars in millions)

	2018	2019	2020	2021	2022	Thereafter	Total
Future minimum lease payments	$ 22	$ 21	$ 20	$ 19	$ 18	$ 54	$ 154
Future estimated rental payments	2	2	2	2	2	3	13
Total future rental commitments	$ 24	$ 23	$ 22	$ 21	$ 20	$ 57	$ 167

Capital Leases

Power Purchase Agreements

SDG&E has five PPAs with peaker plant facilities, one of which went into commercial operation in June 2017. All five are accounted for as capital leases, four with a 25-year term and one with a 9-year term. At December 31, 2017, the aggregate carrying value of these capital lease obligations is $731 million.

In 2017, SDG&E satisfied all of the conditions precedent for a CPUC-approved 20-year PPA with a 500-MW power plant facility that is under construction. Beginning with the initial delivery of the contracted power, scheduled in June 2018, the PPA 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. SDG&E does not have any additional implicit or explicit financial responsibility related to these VIEs.

At December 31, 2017, the future minimum lease payments and present value of the net minimum lease payments under these capital leases for SDG&E are as follows:

FUTURE MINIMUM PAYMENTS – POWER PURCHASE AGREEMENTS
(Dollars in millions)

2018	$ 259
2019	540
2020	210
2021	210
2022	210
Thereafter	3,299
	4,728
Total minimum lease payments(1)	
Less: estimated executory costs	(502)
Less: interest(2)	(2,591)
Present value of net minimum lease payments(3)	$ 1,635

(1) *This amount will be recorded over the lives of the leases as Cost of Electric Fuel and Purchased Power on 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 $54 million in Current Portion of Long-Term Debt and $1,031 million in Long-Term Debt on the Balance Sheet at December 31, 2017. The remaining present value of net minimum lease payments of $550 million will be recorded as a capital lease obligation when construction of the power plant facility is completed and delivery of contracted power commences, which is scheduled to occur in June 2018.*

The annual amortization charges for the PPAs were $46 million, $39 million, and $36 million in 2017, 2016 and 2015, respectively.

Other Capital Leases

SDGE entered into new capital leases in 2017 for additional fleet vehicles. At December 31, 2017, the related capital lease obligations were $1 million, payable in 2018.

The annual depreciation charge for fleet vehicles and other assets in 2017, 2016 and 2015 was $1 million, $1 million and $2 million, respectively.

Construction and Development Projects

At December 31, 2017, SDG&E has commitments to make future payments of $117 million for construction projects that include

- $72 million for infrastructure improvements for natural gas and electric transmission and distribution operations;
- $35 million for the engineering, material procurement and construction costs primarily associated with the Sycamore-Peñasquitos Transmission Project; and
- $10 million related to spent fuel management at SONGS.

SDG&E expects future payments under these contractual commitments to be $78 million in 2018, $9 million in 2019, $19 million in 2020, $5 million in 2021, $1 million in 2022 and $5 million thereafter.

At December 31, 2017, SDG&E has commitments to make future payments of $3 million for contracts related to the procurement of gas rotary meters. SDG&E expects the future payments under these contractual commitments to approximate $1 million each year in 2018 through 2020.

OTHER COMMITMENTS

We discuss nuclear insurance and nuclear fuel disposal related to SONGS in Note 10.

In connection with the completion of the Sunrise Powerlink project in 2012, the CPUC required that SDG&E 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 $3 million per year in 2018 through 2022 and $104 million thereafter, subject to escalation of 2 percent per year, for a remaining 52-year period. At December 31, 2017, the present value of these future payments of $119 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 $119 million.

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 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,		
	2017	2016	2015
SDG&E	$ 46	$ 17	$ 24

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 include (1) investigation and remediation of 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 table below shows the status at December 31, 2017 of the 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 complete	# Sites in process
Manufactured-gas sites	3	—
Third-party waste-disposal sites	2	1

(1) There may be ongoing 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, 2017:

ACCRUED LIABILITIES FOR ENVIRONMENTAL MATTERS
(Dollars in millions)

	Manufactured - gas sites	Waste disposal sites (PRP)	Other hazardous waste sites	Total(2)
SDG&E(3)	$ —	$ 2	$ 2	$ 4

(1) Sites for which we have been identified as a PRP.

(2) Includes $1 million classified as current liabilities, and $3 million classified as noncurrent liabilities on SDG&E's Balance Sheet.

(3) Does not include SDG&E's liability for SONGS marine environment 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 SDG&E's mitigation obligation. SDG&E's share of the estimated mitigation costs is $68 million, of which $44 million has been incurred through December 31, 2017 and $24 million is accrued for remaining costs through 2050, which is recoverable in rates and included in noncurrent Regulatory Assets on SDG&E's Balance Sheet. The requirements for enhanced fish protection and restoration of coastal wetlands for the SONGS mitigation are in process. Work on the artificial reef that was dedicated in 2008 continues. The CCC has stated that it now requires an expansion of the reef because the existing reef may be too small to consistently meet the performance standards. In December 2016, SDG&E and Edison filed a joint application with the CPUC seeking rate recovery of the costs of the reef expansion. In October 2017, SDG&E, Edison, TURN and ORA filed a joint motion requesting approval of a settlement agreement that amends the rate recovery application and allows costs to be recorded to a memorandum account until rate recovery is approved in the second half of 2018. Rates, if approved, would be effective January 2019. SDG&E's share of the reef expansion costs currently forecasted through 2020 is $4 million. We expect a decision on the settlement agreement in the first half of 2018.

CONCENTRATION OF CREDIT RISK

We maintain credit policies and systems designed 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.

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

GLOSSARY

2016 GRC FD	final decision in the California Utilities' 2016 General Rate Case
AB	Assembly Bill
AFUDC	allowance for funds used during construction
AOCI	accumulated other comprehensive income (loss)
ARO	asset retirement obligation
ASC	Accounting Standards Codification

ASU	Accounting Standards Update
bps	basis points
CAISO	California Independent System Operator
California Utilities	San Diego Gas & Electric Company and Southern California Gas Company, collectively
CCC	California Coastal Commission
CCM	cost of capital adjustment mechanism
CPUC	California Public Utilities Commission
CRR	congestion revenue right
DOE	U.S. Department of Energy
Edison	Southern California Edison Company, a subsidiary of Edison International
EPS	earnings per common share
ERRA	Energy Resource Recovery Account
ETR	effective income tax rate
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GRC	General Rate Case
IRS	Internal Revenue Service
ISFSI	independent spent fuel storage installation
IRC	U.S. Internal Revenue Code of 1986 (as amended)
ITC	investment tax credit
LIFO	last in first out
LNG	liquefied natural gas
MHI	Mitsubishi Heavy Industries, Ltd., Mitsubishi Nuclear Energy Systems, Inc., and Mitsubishi Heavy Industries America, Inc., collectively
MMBtu	million British thermal units (of natural gas)
MW	megawatt
MWh	megawatt hour
NDT	nuclear decommissioning trusts
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission
OCI	other comprehensive income (loss)
OII	Order Instituting Investigation
O&M	operation and maintenance expense
OMEC	Otay Mesa Energy Center
ORA	CPUC Office of Ratepayer Advocates
PBOP	postretirement benefits other than pension
PG&E	Pacific Gas and Electric Company
PPA	power purchase agreement
PP&E	property, plant and equipment
PRP	Potentially Responsible Party
PSEP	Pipeline Safety Enhancement Plan
RAMP	Risk Assessment Mitigation Phase
REC	renewable energy certificate
ROE	return on equity
RPS	Renewables Portfolio Standard
RSA	restricted stock award

RSU	restricted stock unit
SB	Senate Bill
SDG&E	San Diego Gas & Electric Company
SEC	U.S. Securities and Exchange Commission
SFP	secondary financial protection
SGRP	Steam Generator Replacement Project
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
SONGS OII	CPUC's Order Instituting Investigation into the SONGS Outage
S&P	Standard & Poor's
TCJA	Tax Cuts and Jobs Act of 2017
TO4	Electric Transmission Formula Rate, effective through December 31, 2018
TO5	Electric Transmission Formula Rate, new application
Tribunal	International Chamber of Commerce International Court of Arbitration Tribunal
TURN	The Utility Reform Network
U.S. GAAP	accounting principles generally accepted in the United States of America
VIE	variable interest entity

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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		(7,840,314)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		361,249		
4	Total (lines 2 and 3)		361,249		
5	Balance of Account 219 at End of Preceding Quarter/Year		(7,479,065)		
6	Balance of Account 219 at Beginning of Current Year		(7,479,065)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(738,203)		
9	Total (lines 7 and 8)		(738,203)		
10	Balance of Account 219 at End of Current Quarter/Year		(8,217,268)		

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			(7,840,314)	[redacted]	[redacted]
2				[redacted]	[redacted]
3			361,249	[redacted]	[redacted]
4			361,249	569,569,312	569,930,561
5			(7,479,065)	[redacted]	[redacted]
6			(7,479,065)	[redacted]	[redacted]
7				[redacted]	[redacted]
8			(738,203)	[redacted]	[redacted]
9			(738,203)	406,693,763	405,955,560
10			(8,217,268)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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)	16,921,981,300	13,647,237,397
4	Property Under Capital Leases	1,374,865,793	1,352,823,281
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	18,296,847,093	15,000,060,678
9	Leased to Others	85,194,000	85,194,000
10	Held for Future Use	4,941,795	4,941,795
11	Construction Work in Progress	1,450,531,198	1,088,889,132
12	Acquisition Adjustments	3,750,722	3,750,722
13	Total Utility Plant (8 thru 12)	19,841,264,808	16,182,836,327
14	Accum Prov for Depr, Amort, & Depl	6,284,565,920	4,922,604,937
15	Net Utility Plant (13 less 14)	13,556,698,888	11,260,231,390
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,494,786,916	4,464,229,878
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	771,180,711	439,776,766
22	Total In Service (18 thru 21)	6,265,967,627	4,904,006,644
23	Leased to Others		
24	Depreciation	17,098,004	17,098,004
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	17,098,004	17,098,004
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	1,500,289	1,500,289
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,284,565,920	4,922,604,937

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
2,186,086,405				1,088,657,498	3
				22,042,512	4
					5
					6
					7
2,186,086,405				1,110,700,010	8
					9
					10
117,575,239				244,066,827	11
					12
2,303,661,644				1,354,766,837	13
784,665,499				577,295,484	14
1,518,996,145				777,471,353	15
					16
					17
776,080,044				254,476,994	18
					19
					20
8,585,455				322,818,490	21
784,665,499				577,295,484	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
784,665,499				577,295,484	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	(241,333,489)	354,066,511
Orange Grove	123,238,342	(10,295,695)	112,942,647
El Cajon Energy	59,751,923	(8,541,069)	51,210,854
Escondido	59,549,016	(3,543,514)	56,005,502
Fleet	22,042,512	(21,123,898)	918,614
Yuma	14,884,000	(355,881)	14,528,119
Pio Pico	500,000,000	(3,415,109)	496,584,891
	1,374,865,793	(288,608,655)	1,086,257,138

Schedule Page: 200 Line No.: 33 Column: b

Reclassification as of 12/2017 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	107,099,789
Steam Production Plant	235,823,380
Other Production Plant	217,767,329
Transmission Plant	1,060,915,697
Distribution Plant	2,849,704,066
General Plant	153,384,798
Ratemaking Electric	4,624,695,059
Nuclear Decommissioning	1,032,230,442
ASC 410 (FAS 143 and FIN 47) - Electric	(1,036,759,072)
Capital Leases A/D	267,484,757
Leased to Others- Citizens A/D	17,098,004
Cuyamaca Permanent Adjustment	17,855,747
Total Electric	4,922,604,937
Ratemaking Gas	996,816,750
FIN 47 - Gas	(212,151,251)
Total Gas	784,665,499
Ratemaking Common	553,468,944
FIN 47 - Common	2,702,642
Fleet Capital Lease A/D	21,123,898
Total Common	577,295,483

Total Accumulated Provision EOQ 12/2017	6,284,565,920
Total 13-Month Average Accum. Provision as of 12/31/2017 -Steam Production	225,442,938
Total 13-Month Average Accum. Provision as of 12/31/2017 -Nuclear Production	-
Total 13-Month Average Accum. Provision as of 12/31/2017 -Other Production	207,428,211
Total 13-Month Average Accum. Provision as of 12/31/2017 -Transmission Plant	1,003,674,902

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/Q4

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	153,458,222	20,676,952
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	153,681,063	20,676,952
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	95,472,041	967,145
10	(312) Boiler Plant Equipment	168,150,619	4,188,911
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	138,276,524	89,688
13	(315) Accessory Electric Equipment	85,716,404	270,315
14	(316) Misc. Power Plant Equipment	46,959,891	2,270,151
15	(317) Asset Retirement Costs for Steam Production	224,916	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	549,326,913	7,786,210
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	-53,605
38	(341) Structures and Improvements	22,748,227	294,953
39	(342) Fuel Holders, Products, and Accessories	21,951,980	43,732
40	(343) Prime Movers	98,559,475	6,881,075
41	(344) Generators	345,543,995	16,487,645
42	(345) Accessory Electric Equipment	33,389,503	
43	(346) Misc. Power Plant Equipment	26,620,429	2,564,929
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	549,013,117	26,218,729
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,098,340,030	34,004,939

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/Q4

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	222,048,545	5,820,055
49	(352) Structures and Improvements	477,012,672	39,739,913
50	(353) Station Equipment	1,403,343,803	256,126,465
51	(354) Towers and Fixtures	894,860,415	2,452,059
52	(355) Poles and Fixtures	453,557,667	90,578,855
53	(356) Overhead Conductors and Devices	568,267,074	51,829,457
54	(357) Underground Conduit	354,564,090	6,306,330
55	(358) Underground Conductors and Devices	372,785,913	18,003,097
56	(359) Roads and Trails	309,857,332	6,296,325
57	(359.1) Asset Retirement Costs for Transmission Plant	1,316,858	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	5,057,614,369	477,152,556
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	101,281,388	1,764,805
61	(361) Structures and Improvements	4,684,421	-33,622
62	(362) Station Equipment	497,743,667	18,896,215
63	(363) Storage Battery Equipment	38,262,883	86,799,715
64	(364) Poles, Towers, and Fixtures	671,234,956	53,470,905
65	(365) Overhead Conductors and Devices	612,265,759	72,245,220
66	(366) Underground Conduit	1,179,180,815	77,662,334
67	(367) Underground Conductors and Devices	1,477,509,704	72,843,973
68	(368) Line Transformers	632,216,823	28,385,581
69	(369) Services	488,489,027	24,576,587
70	(370) Meters	249,165,319	4,815,123
71	(371) Installations on Customer Premises	8,616,917	563,960
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	29,637,524	1,077,853
74	(374) Asset Retirement Costs for Distribution Plant	8,049,762	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,998,338,965	443,068,649
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	33,480,596	9,382,574
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	58,146	
90	(393) Stores Equipment	8,546	
91	(394) Tools, Shop and Garage Equipment	25,958,242	7,178,963
92	(395) Laboratory Equipment	5,152,106	
93	(396) Power Operated Equipment	60,529	
94	(397) Communication Equipment	271,081,975	14,477,650
95	(398) Miscellaneous Equipment	5,799,585	3,722,461
96	SUBTOTAL (Enter Total of lines 86 thru 95)	348,911,868	34,761,648
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)	348,911,868	34,761,648
100	TOTAL (Accounts 101 and 106)	12,656,886,295	1,009,664,744
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)	12,656,886,295	1,009,664,744

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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
			174,135,174		4
			174,358,015		5
					6
					7
			14,526,518		8
			96,439,186		9
			172,339,530		10
					11
			138,366,212		12
			85,986,719		13
			49,230,042		14
			224,916		15
			557,113,123		16
					17
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		80,893	226,796		37
			23,043,180		38
			21,995,712		39
			105,440,550		40
1,704,315	-3,035		360,324,290		41
			33,389,503		42
			29,185,358		43
					44
1,704,315	-3,035	80,893	573,605,389		45
1,704,315	-3,035	80,893	1,130,718,512		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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
	-2,513	6,365,933	234,232,020		48
110,784	-27,792		516,614,009		49
1,037,826	-147,940	55,749	1,658,340,251		50
	-176		897,312,298		51
3,946,996	-30,565		540,158,961		52
551,114	-29,437		619,515,980		53
265	-30,346		360,839,809		54
169,278	-941		390,618,791		55
	-13,861		316,139,796		56
	153,781		1,470,639		57
5,816,263	-129,790	6,421,682	5,535,242,554		58
					59
	109,172		103,155,365		60
			4,650,799		61
787,403		-118,757	515,733,722		62
	-1,136,750		123,925,848		63
11,427,505			713,278,356		64
2,289,148			682,221,831		65
2,626,902			1,254,216,247		66
8,913,400	3,035		1,541,443,312		67
3,401,104			657,201,300		68
1,817,728			511,247,886		69
487,869	-2,864,539		250,628,034		70
21,930			9,158,947		71
					72
127,752			30,587,625		73
	18,284,793		26,334,555		74
31,900,741	14,395,711	-118,757	6,423,783,827		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			7,312,143		86
			42,863,170		87
					88
			58,146		89
5,605			2,941		90
584,589			32,552,616		91
			5,152,106		92
			60,529		93
11,840		63,007	285,610,792		94
			9,522,046		95
602,034		63,007	383,134,489		96
					97
					98
602,034		63,007	383,134,489		99
40,023,353	14,262,886	6,446,825	13,647,237,397		100
					101
					102
					103
40,023,353	14,262,886	6,446,825	13,647,237,397		104

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

Reclassification of 2017 Electric Plant-in-Service for Ratemaking
Plant in Service Classified under FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	BOY 2017	EOY 2017
Intangible Plant	153,458,222	174,135,173
Steam Production Plant	564,106,118	572,066,955
Nuclear Production Plant	-	-
Other Production Plant	491,797,479	518,147,671
Transmission Plant	4,989,264,259	5,463,231,690
Distribution Plant	6,085,651,791	6,494,386,287
General Plant	348,911,866	383,134,487
Ratemaking Electric	12,633,189,735	13,605,102,263
ASC 410 (FAS 143 and FIN 47)	9,591,535	28,030,109
Cuyamaca Permanent Adjustment	14,105,025	14,105,025
Total Electric Plant-in-Service	12,656,886,295	13,647,237,397

Total 13-Month Average Plant Balance for 2017 - Steam Production	567,645,770
Total 13-Month Average Plant Balance for 2017 - Nuclear Production	0
Total 13-Month Average Plant Balance for 2017 - Other Production	510,399,453
Total 13-Month Average Plant Balance for 2017 - Transmission Plant	5,165,035,439

* As a result of the SONGS plant closure, the December 2017 Nuclear Production Plant Balance is zero.

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		
3					
4					
5					
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44					
45					
46					
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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	Ocean Ranch	03/31/2013	01/22/2018	4,941,795
4				
5				
6				
7				
8				
9				
10				
11				
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13				
14				
15				
16				
17				
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21	Other Property:			
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44				
45				
46				
47	Total			4,941,795

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

The 13-Month Average Electric Transmission Plant Held for Future Use is $2,812,889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	PALOMAR ENERGY CENTER OPERATIONAL ENHANCEMENTS	3,152,194
2	TRANSMISSION PROJECTS UNDER $500K	24,866,648
3	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	10,264,129
4	CRITICAL ASSET SECURITY	29,179,051
5	TL663 MISSION-KEARNY RECONDUCTOR	8,653,351
6	SUBSTATION SECURITY PROJECTS UNDER $500K	4,611,101
7	SYCAMORE-PENASQUITOS NEW 230KV TIE LINE	169,199,467
8	ARTESIAN 230KV SUBSTATION EXPANSION	4,238,079
9	CAMP PENDLETON VOLTAGE SUPPORT	4,079,828
10	ORANGE COUNTY LONG RANGE PLAN	69,176,957
11	AUTOMATED FAULT DETECTION INSTALLATIONS	1,341,453
12	TL674A RECONFIGURE	2,204,431
13	MIGUEL SUBSTATION SITE IMPROVEMENTS	3,823,372
14	WARNER SUBSTATION 69KV RELAY UPGRADES	2,875,769
15	DESCANSO SUBSTATION CONTROL & PROTECTION REPLACEMENT	3,234,645
16	SOUTH BAY SUBSTATION RELOCATION	2,704,713
17	TL6926 RINCON-VALLEY CENTER POLE REPLACEMENT	6,179,170
18	SCADA EXPANSION - TRANSMISSION	3,227,887
19	MESA 230KV SUBSTATION	89,422,471
20	IMPERIAL VALLEY SUBSTATION SECURITY	2,111,977
21	MISSION SUBSTATION BANK ADDITION	5,008,753
22	TL680A UPGRADES	3,381,363
23	TL6943 UNDERGROUND CONVERSION	3,632,683
24	TL664 WOOD POLE REPLACEMENT	2,425,491
25	SUBSTATION AUXILIARY POWER SYSTEMS	2,184,097
26	TALEGA SUBSTATION - BANK 50 REPLACEMENT	1,163,654
27	CARLSBAD ENERGY CENTER PROJECT	1,707,292
28	LOS COCHES SUBSTATION REBUILD	16,199,953
29	TL649 POLE REPLACEMENT	4,433,824
30	TL6975 ESCONDIDO - SAN MARCOS	2,554,986
31	SYNCHRONIZED PHASOR MEASUREMENT SYSTEM	3,813,748
32	TL615/659 CABLE REPLACEMENT	3,822,917
33	SUBSTATION RELIABILITY UPGRADE PROJECT	5,188,980
34	IMPERIAL VALLEY SUBSTATION BANK REPLACEMENT	5,399,079
35	TL633 RECONDUCTOR	9,707,853
36	CONDITION BASED MONITORING - CIRCUIT BREAKERS	5,622,465
37	MERCHANT SWITCHYARD	15,554,707
38	TL690 WOOD TO STEEL REPLACEMENT	2,305,835
39	POWAY SUBSTATION REBUILD	18,637,965
40	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	19,897,229
41	SUBSTATION MONITORING EQUIPMENT - TRANSMISSION	1,262,843
42	TL691 WOOD TO STEEL REPLACEMENT	2,624,843
43	TOTAL	1,088,889,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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 INFRASTRUCTURE IMPROVEMENTS	17,741,464
2	TL695 SW POLE REPLACEMENT	4,293,496
3	TL697 WOOD TO STEEL REPLACEMENT	3,406,311
4	TL6912 WOOD TO STEEL REPLACEMENT	2,131,844
5	TL676 MISSION - MESA HEIGHTS RECONDUCTOR	2,345,753
6	TL664 SOUTHBAY-SWEETWATER UPGRADE	2,537,451
7	MIGUEL-BAY BLVD NEW 230KV LINE	1,255,701
8	AERIAL MARKING FOR SAFETY	5,428,553
9	SOUTHWEST POWERLINK HIGH VOLTAGE CONVERSION	1,115,836
10	CLEVELAND NATIONAL FOREST POLE REPLACEMENTS	160,279,450
11	138KV & 69KV CIRCUIT BREAKER UPGRADES	2,109,787
12	TRANSMISSION SYSTEM AUTOMATION	5,488,597
13	DISTRIBUTION SUBSTATION RELIABILITY	3,067,713
14	ELECTRIC DISTRIBUTION STREET & HIGHWAY RELOCATIONS	2,442,193
15	CONVERSION FROM OH TO UG RULE 20A	25,149,383
16	CITY OF SAN DIEGO SURCHARGE PROGRAM	2,052,398
17	UG RESIDENTIAL NEW BUSINESS	6,504,241
18	NEW BUSINESS INFRASTRUCTURE	2,476,287
19	NEW SERVICE INSTALLATIONS	1,032,580
20	OH DISTRIBUTION SERVICE MANAGEMENT	1,913,008
21	UG DISTRIBUTION SERVICE MANAGEMENT	1,088,364
22	CORRECTIVE MAINTENANCE PROGRAM	2,434,112
23	REPLACEMENT OF UNDERGROUND CABLES	4,120,591
24	WOOD POLE REINFORCEMENT	7,005,822
25	DISTRIBUTION CIRCUIT RELIABILITY CONSTRUCTION	1,681,354
26	KEARNY SUBSTATION REBUILD	14,643,691
27	KETTNER SUBSTATION REBUILD	34,720,388
28	BORREGO SPRINGS MICROGRID ENHANCEMENTS	7,848,512
29	DISTRIBUTION SUBSTATION SCADA EXPANSION	4,585,810
30	SUBSTATION BREAKER AND RELAY REPLACEMENTS	3,040,302
31	C1226 NEW 12KV BANK	2,538,440
32	RANCHO SANTA FE SUBSTATION FIRE HARDENING	5,187,406
33	STRATEGIC FIRE HARDENING	35,869,015
34	FIRE HAZARD PREVENTION	2,765,653
35	VEHICLE GRID INTEGRATION	8,985,104
36	GAS INSULATED SWITCH REPLACEMENT	3,716,382
37	EXPEDITED STORAGE PROCUREMENT	3,165,900
38	OCEAN RANCH LAND PURCHASE	6,738,355
39	SUBSTATION CAPACITOR BANK UPGRADES	3,430,667
40	WIRELESS FAULT INDICATORS	1,316,001
41	TEE MODERNIZATION PROGRAM	1,474,371
42	C1023 NEW 12KV CIRCUIT	3,673,125
43	TOTAL	1,088,889,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	JAMUL SUBSTATION	1,244,584
2	SALT CREEK SUBSTATION	4,320,081
3	MID-COAST TROLLEY EXTENSION PROJECT	6,441,097
4	C917 NEW 12KV CIRCUIT	1,674,889
5	VANDIUM FLOW BATTERY PROJECT	1,163,929
6	FIRE THREAT ZONE PROTECTION & SCADA UPGRADE	3,297,196
7	SEWAGE PUMP STATION REBUILDS	11,376,265
8	CONDITION BASED MONITORING - SMART GRID	3,438,183
9	POINT LOMA SUSBSTATION - INSTALL 3RD BANK	12,951,709
10	C1440 NEW 12KV CIRCUIT	1,449,167
11	MASTER METER MOBILE HOME PARK TRANSFERS	4,525,480
12	SCADA CONTROL PANEL REPLACEMENT	3,204,311
13	OBSOLETE SUBSTATION EQUIPMENT REPLACEMENT	8,032,253
14	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLAC. & MANHOLE REPAIR	2,784,641
15	CATASTROPHIC EVENT - 2017	1,038,046
16	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	3,726,178
17	MINOR PROJECTS (LESS THAN $1,000,000)	24,342,459
18	RESEARCH, DEVELOPMENT & DEMONSTRATION	
19		
20		
21	ANNUAL CHANGES IN PROJECT BALANCES ARE DUE TO COMPLETION OF	
22	SEPARATE SEGMENTS OF THE BUDGET	
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43	TOTAL	1,088,889,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,147,123,550	4,132,862,506		14,261,044
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	430,728,774	430,728,774		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others	2,836,960			2,836,960
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)	433,565,734	430,728,774		2,836,960
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	40,023,353	40,023,353		
13	Cost of Removal	59,629,454	59,629,454		
14	Salvage (Credit)	1,440,632	1,440,632		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	98,212,175	98,212,175		
16	Other Debit or Cr. Items (Describe, details in footnote):	6,845,479	6,845,479		
17					
18	Book Cost or Asset Retirement Costs Retired	-7,994,706	-7,994,706		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,481,327,882	4,464,229,878		17,098,004
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	236,491,597	236,491,597		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	226,803,916	226,803,916		
25	Transmission	1,087,823,086	1,070,725,082		17,098,004
26	Distribution	2,776,824,486	2,776,824,486		
27	Regional Transmission and Market Operation				
28	General	153,384,797	153,384,797		
29	TOTAL (Enter Total of lines 20 thru 28)	4,481,327,882	4,464,229,878		17,098,004

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

Depreciation Provision - Electric Only (Line 10, Page 219)	$ 430,728,774
Depreciation Provision - Common Alloc. to Elec. (Line 11, pg 336)	26,691,702
Depreciation Provision - (Line 6, Col. G, Page 115)	$ 457,420,476
	=============

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

Book Cost of Plant Retired (Line 12, Col. B, Page 219)	$(40,023,353)
Total Plant Retired (Line 100, Col. D, Page 207	40,023,353
Adj. For Land & Intangible Retirements not impacting A/C 108	0
Adj. For Net Book Value of Plant Retired to Gain on Sale	0
Difference:	$ 0
	=============

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

SONGS Decommissioning - Current Year Trust Income (Loss)	$ 6,846,674
Transfer of Reserve Balances between Departments	(1,195)
Other Debit and Credit Items (Line 16, Page 219)	$ 6,845,479
	=============

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
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
				7
				8
				9
				10
				11
				12
				13
				14
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)	2,289,968	3,447,152	
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)	8,893,053	126,581,577	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	7,603,749	9,174,748	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)	96,318,462	367,535	ELECTRIC/GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	112,815,264	136,123,860	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			COMMON
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			COMMON
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	115,105,232	139,571,012	

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

Reclassification of FERC Form 1 2017 Materials & Supplies, Page 227, for Ratemaking

Materials and Supplies Classified

In accordance with Guidelines in FERC Order 888

	EOY 2017	
Total Materials and Supplies (FERC 154)	136,123,860	1
As Assigned to Department for Ratemaking		
Electric Department	132,643,410	
Gas Department	3,480,450	
Total Allowable Materials and Supplies per FERC Formula	132,643,410	2
Total 13-Month Average Electric M&S for 2017	119,385,434	

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

[2] Ties to Line 13 of Cost Statement AL supporting workpaper, in TO5 Cycle 1 FERC Filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	92,868.00			
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	Transfer to Palomar	-6.00			
10	Transfer to Desert Star	-2.00			
11					
12					
13					
14					
15	Total	-8.00			
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	105,807.00		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) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						92,868.00		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
								11
								12
								13
								14
						-8.00		15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
12,947.00		12,947.00		349,569.00		494,217.00		29
								30
								31
								32
								33
								34
								35
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								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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		2018	
		No. (b)	Amt. (c)	No. (d)	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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	SONGS Plant Shutdown Project	182,747,145		Various	182,747,145	
22	Electric Legacy Meters Project	16,120,750		Various	16,120,750	
23	Sycamore-Bernardo Project	1,366,481				1,366,481
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	200,234,376			198,867,895	1,366,481

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Taxes Recoverable in Rates	1,040,780,150		Various	308,306,910	732,473,240
2	Amortized Over Various Lives					
3						
4	Post Retirement Benefits Other Than Pension	21,236,191		228	21,236,191	
5						
6	Employer's Accounting for Postemployment Benefits	3,677,000		228/232/14	250,000	3,427,000
7						
8	Environmental Clean-Up	1,619,384	2,932,073			4,551,457
9						
10	Balancing Account Undercollections	559,876,310		456 / 495	54,070,323	505,805,987
11						
12	Pension Benefits	188,278,184		228	25,410,108	162,868,076
13						
14	SONGS Mitigation	46,448,539		253	22,431,545	24,016,994
15						
16	Electric Derivatives	243,048,609		175 / 244	17,629,752	225,418,857
17						
18	Contribution to City of Escondido	1,473,016		253	131,511	1,341,505
19	(20 year life, starting 2006)					
20						
21	Asset Retirement Obligations	14,878,751	1,383,679			16,262,430
22						
23	2007 Excess Wildfire Claims	353,763,531		456	353,763,531	
24						
25	Sunrise Wildfire Mitigation	118,005,593	924,500			118,930,093
26						
27	Beyond The Meter	8,082,451	12,012,097	407.3	1,510,600	18,583,948
28						
29	Unamortized Line of Credit (LOC) Net	1,437,985		930	375,150	1,062,835
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	2,602,605,694	17,252,349		805,115,621	1,814,742,422

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	Debt Issuance Costs	623,971		431	242,659	381,312
2						
3	Southwest Powerlink Deferred					
4	per CPUC					
5	(amortization 1/1986 - 12/2023)	348,010		406	15,744	332,266
6						
7	Mitigation Fund	150,328		various	12,622	137,706
8						
9	Environmental Program	7,170,033	15,277	various	988,355	6,196,955
10						
11	Oracle Costs	1,046,846	318,816	various	1,365,662	
12						
13	Workers Comp Receivable	8,044,261	494,977	various	727,510	7,811,728
14						
15	SONGS Decommissioning	1,803,788	2,725,661	228	2,233,082	2,296,367
16						
17	Pendleton Energy Park	195,734				195,734
18						
19	Gaskell Tax Equity	115,312				115,312
20						
21	Supervisory Control & Data	514,734		various	16,070	498,664
22	Acquisition Equipment					
23						
24	Misc. Deferred Debits - SONGS	3,238,229	314,552	various	3,552,781	
25						
26	SONGS Reg Asset Receivable		119,974,302			119,974,302
27						
28	PBOP Asset		10,065,432			10,065,432
29						
30	Surplus Material		1,978,396			1,978,396
31						
32	Miscellaneous Other	138,707	5,365	921	428	143,644
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	23,389,953				150,127,818

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	125,517,335	65,586,640
3	State	69,353,253	63,253,360
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	194,870,588	128,840,000
9	Gas		
10	Federal	34,664,148	4,641,292
11	State	3,539,965	2,352,225
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	38,204,113	6,993,517
17	Other (Specify) Non-Utiltity	83,877,846	57,781,336
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	316,952,547	193,614,853

Notes

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

Account 190 non-Citizen transmission related deferred tax (asset)related to net operating losses included in electric accumulated deferred income taxes at the beginning of the year was ($287,918,000).

Account 190 Citizen transmission related deferred tax (asset) related to net operating losses included in electric accumulated deferred income taxes at the beginning of the year was ($14,837,000).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($2,445,558).

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

Account 190 non-Citizen transmission related deferred tax (asset) related to net operating losses included in electric accumulated deferred income taxes at the end of the year was ($270,712,000).

Account 190 Citizen transmission related deferred tax (asset) related to net operating losses included in electric accumulated deferred income taxes at the end of the year was ($13,950,000).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($2,397,323).

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
						5
						6
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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
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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		
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	5.875% Series VV due 2034	43,615,000	1,509,414
5			
6	5.875% Series WW due 2034	40,000,000	1,385,317
7			
8	5.875% Series XX due 2034	35,000,000	1,213,328
9			
10	5.875% Series YY due 2034	24,000,000	832,448
11			
12	5.875% Series ZZ due 2034	33,650,000	1,165,922
13			
14	4.000% Series AAA due 2039	75,000,000	3,089,247
15			
16	5.350% Series BBB due 2035	250,000,000	2,709,950
17			295,000 D
18	6.000% Series DDD due 2026	250,000,000	2,429,000
19			1,117,500 D
20	1.650% Series EEE due 2018	161,240,000	4,375,665
21			
22	6.125% Series FFF due 2037	250,000,000	2,556,327
23			780,000 D
24	6.000% Series GGG due 2039	300,000,000	3,057,571
25			1,380,000 D
26	5.350% Series HHH due 2040	250,000,000	2,486,955
27			335,000 D
28	4.500% Series III due 2040	500,000,000	5,044,008
29			5,515,000 D
30	3.000% Series JJJ due 2021	350,000,000	2,775,568
31			1,795,500 D
32	3.950% Series LLL due 2041	250,000,000	2,639,787
33	TOTAL	4,912,505,000	71,489,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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			350,000 D
2	4.300% Series MMM due 2042	250,000,000	2,569,738
3			1,297,500 D
4	3.600% Series NNN due 2023	450,000,000	3,670,004
5			72,000 D
6	3.7500% Series RRR due 2047	400,000,000	4,022,550
7			1,784,000 D
8	1.914% Series PPP due 2022	250,000,000	1,715,986
9			
10	2.500% Series QQQ due 2026	500,000,000	4,279,086
11			1,625,000 D
12	5.000% Series OO due 2027	250,000,000	1,615,079
13			
14	1.151% Series OOO due 2017		
15			
16	TOTAL ACCOUNT 221	4,912,505,000	71,489,450
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33	TOTAL	4,912,505,000	71,489,450

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
06/17/04	02/15/34	06/17/04	02/15/34	43,615,000	2,562,381	4
						5
06/17/04	02/15/34	06/17/04	02/15/34	40,000,000	2,350,000	6
						7
06/17/04	02/15/34	06/17/04	02/15/34	35,000,000	2,056,250	8
						9
06/17/04	01/01/34	06/17/04	01/01/34	24,000,000	1,410,000	10
						11
06/17/04	01/01/34	06/17/04	01/01/34	33,650,000	1,976,937	12
						13
06/17/04	05/01/39	06/17/04	05/01/39	75,000,000	3,000,000	14
						15
05/19/05	05/15/35	05/19/05	05/15/35	250,000,000	13,375,000	16
						17
06/08/06	06/01/26	06/08/06	06/01/26	250,000,000	15,000,000	18
						19
09/21/06	07/01/18	09/21/06	07/01/18	161,240,000	2,660,460	20
						21
09/20/07	09/15/37	09/20/07	09/15/37	250,000,000	15,312,500	22
						23
05/14/09	06/01/39	05/14/09	06/01/39	300,000,000	18,000,000	24
						25
05/13/10	05/15/40	05/13/10	05/15/40	250,000,000	13,375,000	26
						27
08/26/10	08/15/40	08/26/10	08/15/40	500,000,000	22,500,000	28
						29
08/18/11	08/15/21	08/18/11	08/15/21	350,000,000	10,500,000	30
						31
11/17/11	11/15/41	11/17/11	11/15/41	250,000,000	9,875,000	32
				4,573,220,000	185,808,926	33

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
03/22/12	04/01/42	03/22/12	04/01/42	250,000,000	10,750,000	2
						3
09/09/13	09/01/23	09/09/13	09/01/23	450,000,000	16,200,000	4
						5
06/08/17	06/01/47	06/08/17	06/01/47	400,000,000	8,458,334	6
						7
03/12/15	02/01/22	03/12/15	02/01/22	160,715,000	3,356,188	8
						9
05/19/16	05/15/26	05/19/16	05/15/26	500,000,000	12,500,000	10
						11
12/01/92	12/01/27	12/01/92	12/01/27		225,000	12
						13
					365,876	14
						15
				4,573,220,000	185,808,926	16
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						32
				4,573,220,000	185,808,926	33

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

Expense	$55,142,950
Discount	$16,346,500
Account 221	$71,489,450

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

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. In June 2017 SDG&E issued 3.7500% First Mortgage bond series RRR for $400,000,000 due 2047. At December 2017 total remaining authority for new debt was $305,430,000 and rollover debt was $160,000,000.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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)	406,693,763
2		
3		
4	Taxable Income Not Reported on Books	
5	Regulatory Balancing Accounts	90,764,423
6	Contributions in Aid of Construction	28,145,782
7	SONGS Decommissioning Costs	3,566,346
8	Other (Itemized within footnote)	6,900
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	642,915,996
11	481a - Wildfire Settlements	349,251,645
12	Federal and State Taxes	154,612,449
13	Other (Itemized within footnote)	69,774,668
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	-84,300,909
16	Deferred Construction Revenue	-6,991,966
17	Keyman Life Insurance	-6,138,140
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-934,371,895
21	Percentage Repair Allowance	-137,712,499
22	Current State Tax Deduction	-30,506,728
23	Software Development Costs	-94,249,539
24	Removal Costs	-66,188,844
25	Contingency Book Reserves	-8,850,473
26	Other (Itemized within footnote)	-25,950,866
27	Federal Tax Net Income	350,470,428
28	Show Computation of Tax:	
29	Federal Tax @ 35%	122,664,650
30	Deferred Taxes	-10,936
31	Tax Credits and Other Adjustments (net)	-4,105,740
32	Fed Discrete Taxes	12,422,931
33	Total Federal Income Tax Expense	130,970,905
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44		

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

Fuel Tax Credit Addback	$	6,900
	$	6,900

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

SERP	$	(418,866)
Miscellaneous Expenses		4,942,781
Amortization and Interest Capitalized		59,635,684
Book Loss on Sale of Utility Property		5,615,069
Total	$	69,774,668

Schedule Page: 261 Line No.: 17 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 of Loss on Reacquired Debt	$	6,210,620
Stock Options		(1,448,912)
Abandonment Loss		(6,391,272)
Miscellaneous Expenses		179,343
Section 199 Deduction		(3,368,249)
Property Tax / Ad Valorem		(6,102,606)
Facts & Circumstances Repairs		(15,029,790)
Total	$	(25,950,866)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)		838,416	115,361,126	129,341,478	-13,991,192
3	Sales and Use (Note 2)	78,793		439,652	485,404	
4	Business License			58,602	58,602	
5						
6	SUBTOTAL	78,793	838,416	115,859,380	129,885,484	-13,991,192
7						
8	STATE:					
9	Franchise (Note 3)		40,526,569	64,886,621	26,279,778	-1,332,138
10	Unemployment (Note 4)	596,420		894,551	977,198	
11	Sales and Use (Note 2)	242,696		1,507,375	1,664,241	
12	Fuel Tax	1,703		-1,551	-5,268	
13						
14	SUBTOTAL	840,819	40,526,569	67,286,996	28,915,949	-1,332,138
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)		86,431,535	99,929,149	802,486	5,802,948
18	Retirement (Note 4)	1,038,240		27,179,172	27,175,856	
19	Unemployment (Note 4)	692,115		-398,160	197,530	681,027
20	Medicare (Note 4)	242,774		7,651,926	7,651,111	-19
21	Fuel Tax	31,835		-110,826	20,755	
22						
23						
24	SUBTOTAL	2,004,964	86,431,535	134,251,261	35,847,738	6,483,956
25						
26	Other - Foreign Tax					
27						
28						
29						
30						
31	Note 1					
32						
33	Note 2					
34						
35	Note 3					
36						
37	Note 4					
38						
39						
40						
41	TOTAL	2,924,576	127,796,520	317,397,637	194,649,171	-8,839,374

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 (l) 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
	827,576	102,026,765			13,334,361	2
33,041					439,652	3
		48,427			10,175	4
						5
33,041	827,576	102,075,192			13,784,188	6
						7
						8
	587,588	62,007,746	48,589		2,830,285	9
513,773		669,892			224,659	10
85,830					1,507,375	11
5,420					-1,551	12
						13
605,023	587,588	62,677,638	48,589		4,560,768	14
						15
						16
6,892,180		147,421,808	175,373		-47,668,031	17
1,041,556		10,609,240			16,569,932	18
777,452		-298,165			-99,995	19
243,570		2,986,887			4,665,039	20
	99,746				-110,826	21
						22
						23
8,954,758	99,746	160,719,770	175,373		-26,643,881	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
9,592,822	1,514,910	325,472,600	223,962		-8,298,925	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 $1,891,882

Property Tax expense of $650,880 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 $650,880 associated with the Citizens portion of the Border-Eastline.

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

State

Description	Adjustment Amount	FERC 190	FERC 283	FERC 171	FERC 237
Balance Sheet Reclassification Due to FIN 48 Liabilities	(1,332,138)	1,332,138			
Total - California Corporation Franchise Tax Adjustment	(1,332,138)	1,332,138	-	-	-

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

Federal

Description	Adjustment Amount	FERC 190	FERC 283	FERC 171	FERC 237
Utilization of Net Operating Loss	17,779,476	(17,779,476)			
Balance Sheet Reclass Due to FIN 48 Liab	(5,456,248)		5,456,248		
Balance Sheet Reclass Due to FIN 48 Liab - Interest	(6,520,280)			1,711,227	4,809,053
Total - Federal Income Tax Adjustment	5,802,948	(17,779,476)	5,456,248	1,711,227	4,809,053

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

Payroll Tax expense of $29,108 associated with the Citizens portion of the Border-Eastline are deducted and moved to column (l).

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

Includes payroll tax expense of $29,108 associated with the Citizens portion of Border-Eastline.

Schedule Page: 262 Line No.: 19 Column: f

Adjustment to 2017 Federal Unemployment Tax is due to a rate adjustment.

Schedule Page: 262 Line No.: 31 Column: a

Note 1:
Ad Valorem taxes are allocated based on type of assets in each taxing jurisdiction.

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

Note 2:
Sales and Use taxes are allocated based on the Common Allocation Factor.

Schedule Page: 262 Line No.: 35 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.: 37 Column: a

Note 4:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Various	13,534,913			411.4	-2,117,707	
7							
8	TOTAL	13,534,913				-2,117,707	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility Various	2,500,359			411.4	512,929	
11							
12							
13							
14							
15							
16							
17							
18							
19							
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45							
46							
47							
48							

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
15,652,620	25 to 30 years		6
			7
15,652,620			8
			9
1,987,430	25 to 30 years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
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			31
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			45
			46
			47
			48

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

Account 255 transmission related amortization of investment tax credits allocated to current year income is $264,763.

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	CIAC/CAC Tax Gross-Ups	68,195,663	456/495	11,478,968	9,796,719	66,513,414
2	Amortized over various 31 yr lives					
3						
4	SONGS Mitigation	45,482,375	182.3	23,838,643		21,643,732
5						
6	OII Insurance Limited	6,103,000	924	347,633	1,739,142	7,494,509
7						
8	Sunrise Fire Mitigation Liability	114,637,820	182.3	3,435,126	4,292,271	115,494,965
9						
10	Citizens Lease	69,701,708	242	2,836,960		66,864,748
11						
12	GHG Allowance	71,917,738	158	116,731,052	44,813,314	
13						
14	Miscellaneous	13,396,770	Various	8,389,727	11,283,973	16,291,016
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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41						
42						
43						
44						
45						
46						
47	TOTAL	389,435,074		167,058,109	71,925,419	294,302,384

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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

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

3. 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
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
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							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	1,991,190,433	220,990,673	115,188,815
3	Gas	178,851,631	53,118,499	8,138,458
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,170,042,064	274,109,172	123,327,273
6				
7	Non Utility	66,947,109		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,236,989,173	274,109,172	123,327,273
10	Classification of TOTAL			
11	Federal Income Tax	2,000,184,248	257,877,606	101,569,954
12	State Income Tax	236,804,925	16,231,566	21,757,319
13	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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
			715,514,286			1,381,478,005	2
			77,363,106			146,468,566	3
							4
			792,877,392			1,527,946,571	5
							6
9,220,288	650,720	182.3	14,948,292			60,568,385	7
							8
9,220,288	650,720		807,825,684			1,588,514,956	9
							10
7,361,089	650,720		828,952,269			1,334,250,000	11
1,859,199			-21,126,585			254,264,956	12
							13

NOTES (Continued)

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

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $931,658,150.

Acount 282 Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $22,885,191.

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

Account 282 electric balance at the end of the year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $0.

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $639,177,602.

Account 282 non-Citizen transmission related excess deferred income tax reserve at the end of the year was $388,884,787.

Account 282 Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $13,290,736.

Account 282 Citizen transmission related excess deferred income tax reserve at the end of the year was $8,860,491.

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		773,386,020	87,853,556	277,051,907
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	773,386,020	87,853,556	277,051,907
10	Gas			
11		59,862,882	5,224,789	10,574,021
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	59,862,882	5,224,789	10,574,021
18	Non-Utility	38,759,619		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	872,008,521	93,078,345	287,625,928
20	Classification of TOTAL			
21	Federal Income Tax	682,802,461	80,531,400	230,513,863
22	State Income Tax	189,206,060	12,546,945	57,112,066
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		Various	534,719,854	Various	3,416,580	52,884,395	3
							4
							5
							6
							7
							8
			534,719,854		3,416,580	52,884,395	9
							10
		Various	33,513,481	Various		21,000,169	11
							12
							13
							14
							15
							16
			33,513,481			21,000,169	17
97,045	1,375,046	Various	13,817,765	Various	5,387,902	29,051,755	18
97,045	1,375,046		582,051,100		8,804,482	102,936,319	19
							20
97,045	1,097,779		535,295,829		8,804,482	5,327,917	21
	277,268		46,755,269			97,608,402	22
							23

NOTES (Continued)

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

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the beginning of the year was $4,661,991.

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

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the end of the year was $6,398,443.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Deferred Taxes Payable in rates	26,301,538	Various	79,240,136	1,065,952,884	1,013,014,286
3						
4						
5	Asset Retirement Obligations	516,002,224			37,547,905	553,550,129
6						
7						
8	Balancing Account Overcollections	319,190,489	Various	128,391,430	96,381,934	287,180,993
9						
10						
11	Electric / Gas Derivatives	102,099,723			27,126,103	129,225,826
12						
13						
14	PBOP Benefits				10,065,432	10,065,432
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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35						
36						
37						
38						
39						
40						
41	TOTAL	963,593,974		207,631,566	1,237,074,258	1,993,036,666

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	1,452,724,928	1,385,389,551
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,433,017,503	1,312,141,086
5	Large (or Ind.) (See Instr. 4)	380,874,065	355,650,412
6	(444) Public Street and Highway Lighting	15,116,968	13,575,324
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,281,733,464	3,066,756,373
11	(447) Sales for Resale	508,344,524	430,362,414
12	TOTAL Sales of Electricity	3,790,077,988	3,497,118,787
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,790,077,988	3,497,118,787
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	94,298,549	85,186,823
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,682,000	6,563,517
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-1,227,390	328,495,290
22	(456.1) Revenues from Transmission of Electricity of Others	201,104,161	258,199,601
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	298,857,320	678,445,231
27	TOTAL Electric Operating Revenues	4,088,935,308	4,175,564,018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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
6,577,628	6,684,887	1,280,264	1,272,052	2
				3
6,762,806	6,700,346	151,272	150,591	4
2,203,979	2,193,185	444	461	5
78,670	74,621	2,044	2,028	6
				7
				8
				9
15,623,083	15,653,039	1,434,024	1,425,132	10
13,677,887	13,790,851			11
29,300,970	29,443,890	1,434,024	1,425,132	12
				13
29,300,970	29,443,890	1,434,024	1,425,132	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	$85,592,194
Service Establishment	3,771,444
Net Energy Metering	3,860,299
Late Payment Charge	619,453
Other*	455,159
	$94,298,549

* Individual balances are less than $250,000

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

Description

San Diego Franchise Fee Surcharge	$80,045,984
Service Establishment	3,567,317
Late Payment Charge	597,838
Other*	975,684
	$85,186,823

* Individual balances are less than $250,000

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

Includes Transmission Revenue Credits of $1,157,417

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

Includes Transmission Revenue Credits of $1,732,846

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

Description

Direct Access	$226,309,696
Balancing Accounts	(352,534,128)
Cap and Trade Revenues	99,556,979
Payment Participation	481,290
Litigation	(600,000)
CIAC Income Tax	6,016,129
Shared Assets	5,055,823
PUC Reimbursement Fee	8,069,991
Government Turnkey	(3,093,548)
Joint Pole Activity	2,221,964
Generation Trans. Interconnection Rev.	2,217,642
Affiliation Empl Transfer Fees	1,277,884
Other*	3,792,888
	$ (1,227,390)

* Individual balances are less than $250,000

* Inclueldes Transmission Revenue Credits of $2,896,327

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

Description

Direct Access	$223,238,550
Balancing Accounts	(7,186,248)
Cap and Trade Revenues	82,024,128
Litigation	3,678,316
CIAC Income Tax	6,391,174
Shared Assets	4,870,607
PUC Reimbursement Fee	6,184,516
Government Turnkey	717,068
Unbilled Revenue	1,896,000
Joint Pole Activity	1,862,654
Generation Trans. Interconnection Rev.	2,270,401
Affiliation Empl Transfer Fees	317,745
Other*	2,230,379
	$328,495,290

* Individual balances are less than $250,000
* Inclueldes Transmission Revenue Credits of $3,330,372

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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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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) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	4,999,047	1,222,324,220	984,844	5,076	0.2445
2	DRTOU	125,862	22,653,981	22,758	5,530	0.1800
3	EVTOU	108,584	22,537,869	9,851	11,023	0.2076
4	DRLI	1,133,093	150,616,692	256,649	4,415	0.1329
5	DM	43,241	10,073,696	3,577	12,089	0.2330
6	DS	17,359	2,593,692	234	74,184	0.1494
7	DT	148,601	21,269,882	427	348,012	0.1431
8	OL-1	1,611	517,954	1,880	857	0.3215
9	DWL	230	136,942	44	5,227	0.5954
10	Total Residential Sales (440)	6,577,628	1,452,724,928	1,280,264	5,138	0.2209
11						
12	A	54,898	9,994,847	6,921	7,932	0.1821
13	ATOU	6,552	1,510,211	92	71,217	0.2305
14	ASTOD	2,118,664	468,476,217	122,349	17,317	0.2211
15	AD	27,657	6,940,000	163	169,675	0.2509
16	UM	6,618	1,496,242	93	71,161	0.2261
17	PA	4	882	2	2,000	0.2205
18	PAT1	302,041	51,863,224	3,857	78,310	0.1717
19	AL-TOU	4,160,672	871,543,811	15,745	264,254	0.2095
20	SPSS	2,041	360,622	5	408,200	0.1767
21	DGAL		163,199			
22	AY-TOU	76,478	18,797,788	301	254,080	0.2458
23	OL-1	4,597	1,294,218	1,710	2,688	0.2815
24	OLTOU	2,584	576,242	34	76,000	0.2230
25	Total Commerical (444)	6,762,806	1,433,017,503	151,272	44,706	0.2119
26						
27	AL-TOU	2,154,884	370,584,775	431	4,999,731	0.1720
28	DG		400,585			
29	A6-TOU	49,095	9,888,705	13	3,776,538	0.2014
30	Total Industrial (442)	2,203,979	380,874,065	444	4,963,917	0.1728
31						
32	LS1	15,648	5,921,464	776	20,165	0.3784
33	LS2	61,436	8,956,117	1,115	55,100	0.1458
34	LS3	1,586	239,387	153	10,366	0.1509
35	Total Public Street and Hwy (444)	78,670	15,116,968	2,044	38,488	0.1922
36						
37						
38						
39						
40						
41	TOTAL Billed	15,623,083	3,281,733,464	1,434,024	10,895	0.2101
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	15,623,083	3,281,733,464	1,434,024	10,895	0.2101

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Arizona Public Service Company	SF	FERC Vol. 10			
2	California ISO					
3	City of Escondido (Rincon Hydro Plant)	SF	FERC Vol. 10			
4	City of Burbank	SF	FERC Vol. 10			
5	Energy Authority	SF	FERC Vol. 10			
6	Exelon Generation Company LLC	SF	FERC Vol. 10			
7	Los Angeles Dept. of Water & Power	SF	FERC Vol. 10			
8	Morgan Stanley Capital Group	SF	FERC Vol. 10			
9	Powerex Corporation	SF	FERC Vol. 10			
10	Southern California Edison	SF	FERC Vol. 10			
11	TransAlta Energy Marketing US	SF	FERC Vol. 10			
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.
444		40,404		40,404	1
13,579,922		504,277,729		504,277,729	2
121		17,137		17,137	3
2,000		76,000		76,000	4
3,200		174,400		174,400	5
800		20,000		20,000	6
2,000		92,600		92,600	7
73,400		3,117,054		3,117,054	8
4,800		167,900		167,900	9
800		22,000		22,000	10
10,400		339,300		339,300	11
					12
					13
					14
0	0	0	0	0	
13,677,887	0	508,344,524	0	508,344,524	
13,677,887	**0**	**508,344,524**	**0**	**508,344,524**	

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	1,908,837	1,788,323
5	(501) Fuel	108,006,886	91,381,379
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	269,830	235,768
10	(506) Miscellaneous Steam Power Expenses	7,061,559	8,347,313
11	(507) Rents	34,319	27,061
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	117,281,431	101,779,844
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	235	238
16	(511) Maintenance of Structures	187,301	337,782
17	(512) Maintenance of Boiler Plant	2,465,563	2,321,208
18	(513) Maintenance of Electric Plant	221,622	309,700
19	(514) Maintenance of Miscellaneous Steam Plant	6,102,871	3,317,484
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,977,592	6,286,412
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	126,259,023	108,066,256
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		325,869
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		9,869
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	1,491,648	829,989
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	1,491,648	1,165,727
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	150,872	248,915
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant	19	731
39	(532) Maintenance of Miscellaneous Nuclear Plant		192,545
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	150,891	442,191
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	1,642,539	1,607,918
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)		

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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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	373,110	446,693
63	(547) Fuel	4,596,702	4,218,680
64	(548) Generation Expenses	6,074	
65	(549) Miscellaneous Other Power Generation Expenses	6,519,964	8,536,469
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	11,495,850	13,201,842
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		794
70	(552) Maintenance of Structures	-27,884	25,012
71	(553) Maintenance of Generating and Electric Plant	8,239,411	7,836,538
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	5,115,961	9,518,929
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	13,327,488	17,381,273
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	24,823,338	30,583,115
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,757,208,368	1,589,224,779
77	(556) System Control and Load Dispatching	2,812,365	3,267,145
78	(557) Other Expenses	6,394,783	6,949,874
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,766,415,516	1,599,441,798
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,919,140,416	1,739,699,087
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,370,790	7,744,285
84			
85	(561.1) Load Dispatch-Reliability	573,843	608,045
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,488,163	1,321,142
87	(561.3) Load Dispatch-Transmission Service and Scheduling	208,289	197,927
88	(561.4) Scheduling, System Control and Dispatch Services	6,098,268	5,906,075
89	(561.5) Reliability, Planning and Standards Development	156,512	410,126
90	(561.6) Transmission Service Studies	28	
91	(561.7) Generation Interconnection Studies	1,855	29,157
92	(561.8) Reliability, Planning and Standards Development Services	3,305,693	3,294,992
93	(562) Station Expenses	7,321,035	5,968,735
94	(563) Overhead Lines Expenses	4,984,136	5,140,720
95	(564) Underground Lines Expenses	3,115	7,547
96	(565) Transmission of Electricity by Others		439
97	(566) Miscellaneous Transmission Expenses	19,437,114	20,855,545
98	(567) Rents	2,436,591	2,507,242
99	TOTAL Operation (Enter Total of lines 83 thru 98)	53,385,432	53,991,977
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,056,954	1,492,109
102	(569) Maintenance of Structures	1,181	
103	(569.1) Maintenance of Computer Hardware	1,410,754	1,307,433
104	(569.2) Maintenance of Computer Software	2,052,929	2,296,360
105	(569.3) Maintenance of Communication Equipment	37	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	130,165	368,982
107	(570) Maintenance of Station Equipment	12,091,903	10,303,297
108	(571) Maintenance of Overhead Lines	16,365,161	17,759,358
109	(572) Maintenance of Underground Lines	597,842	355,128
110	(573) Maintenance of Miscellaneous Transmission Plant	3,150	1,917
111	TOTAL Maintenance (Total of lines 101 thru 110)	33,710,076	33,884,584
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	87,095,508	87,876,561

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	3,406,759	3,365,163
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,406,759	3,365,163
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)	3,406,759	3,365,163
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	15,909,212	18,188,602
135	(581) Load Dispatching	2,385,779	2,843,727
136	(582) Station Expenses	3,434,871	5,313,914
137	(583) Overhead Line Expenses	5,666,945	3,088,786
138	(584) Underground Line Expenses	4,201,316	3,049,553
139	(585) Street Lighting and Signal System Expenses	669,949	590,079
140	(586) Meter Expenses	9,457,830	10,905,267
141	(587) Customer Installations Expenses	5,599,731	6,567,025
142	(588) Miscellaneous Expenses	36,641,612	28,855,925
143	(589) Rents	387,609	462,486
144	TOTAL Operation (Enter Total of lines 134 thru 143)	84,354,854	79,865,364
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,658,570	1,474,963
147	(591) Maintenance of Structures	102	1,141
148	(592) Maintenance of Station Equipment	2,099,774	2,248,185
149	(593) Maintenance of Overhead Lines	44,974,258	45,182,924
150	(594) Maintenance of Underground Lines	8,944,324	9,520,845
151	(595) Maintenance of Line Transformers	5,498	11,091
152	(596) Maintenance of Street Lighting and Signal Systems	73,996	124,470
153	(597) Maintenance of Meters	1,556,884	1,895,444
154	(598) Maintenance of Miscellaneous Distribution Plant	707,782	706,540
155	TOTAL Maintenance (Total of lines 146 thru 154)	60,021,188	61,165,603
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	144,376,042	141,030,967
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	84	
160	(902) Meter Reading Expenses	1,968,301	2,300,358
161	(903) Customer Records and Collection Expenses	38,531,346	37,124,281
162	(904) Uncollectible Accounts	5,016,696	4,448,897
163	(905) Miscellaneous Customer Accounts Expenses	852,571	236,979
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	46,368,998	44,110,515

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	575	31,764
168	(908) Customer Assistance Expenses	170,555,193	203,952,339
169	(909) Informational and Instructional Expenses	157,711	105,190
170	(910) Miscellaneous Customer Service and Informational Expenses	3,866,023	3,916,094
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	174,579,502	208,005,387
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	36,248,332	30,638,332
182	(921) Office Supplies and Expenses	7,641,102	8,501,761
183	(Less) (922) Administrative Expenses Transferred-Credit	7,634,719	7,494,244
184	(923) Outside Services Employed	83,058,369	93,114,129
185	(924) Property Insurance	5,391,972	4,342,028
186	(925) Injuries and Damages	95,755,200	87,830,779
187	(926) Employee Pensions and Benefits	40,059,178	32,700,832
188	(927) Franchise Requirements	120,400,695	114,077,380
189	(928) Regulatory Commission Expenses	18,404,990	17,195,211
190	(929) (Less) Duplicate Charges-Cr.	2,220,724	2,227,412
191	(930.1) General Advertising Expenses	192,754	153,179
192	(930.2) Miscellaneous General Expenses	7,233,074	1,497,543
193	(931) Rents	11,960,795	11,234,212
194	TOTAL Operation (Enter Total of lines 181 thru 193)	416,491,018	391,563,730
195	Maintenance		
196	(935) Maintenance of General Plant	9,138,210	8,607,842
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	425,629,228	400,171,572
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,800,596,453	2,624,259,252

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	Arlington Valley Solar II LLC	LU	FERC Vol. 10			
2	Applied Energy Inc	LU	FERC Vol. 10			
3	Avangrid Renewables LLC	LU	FERC Vol. 10			
4	California ISO					
5	Calipatria LLC	LU	FERC Vol. 10			
6	Campo Verde Solar LLC	LU	FERC Vol. 10			
7	Cascade Solar LLC	LU	FERC Vol. 10			
8	Catalina Solar LLC	LU	FERC Vol. 10			
9	Centinela Solar Energy LLC	LU	FERC Vol. 10			
10	Centinela Solar Energy 2 LLC	LU	FERC Vol. 10			
11	City of Escondido (Bear Valley Hydro)	LU	FERC Vol. 10			
12	City of Oceanside (San Francisco Peak)	LU	FERC Vol. 10			
13	City of San Diego (Point Loma)	LU	FERC Vol. 10			
14	Coram Energy LLC	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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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:

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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.

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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	CP Kelco US Inc	LU	FERC Vol. 10			
2	CSolar IV South LLC	LU	FERC Vol. 10			
3	CSolar IV West LLC	LU	FERC Vol. 10			
4	Desert Green Solar Farm LLC	LU	FERC Vol. 10			
5	El Cajon Energy Center (Tolling)	LU	FERC Vol. 10			
6	Energia Sierra Juarez US LLC	LU	FERC Vol. 10			
7	Escondido Energy Center LLC	LU	FERC Vol. 10			
8	FPL Energy Green Power Wind LLC	LU	FERC Vol. 10			
9	Goal Line LP	LU	FERC Vol. 10			
10	Grossmont Hospital Corporation	LU	FERC Vol. 10			
11	HL Power Company LP	LU	FERC Vol. 10			
12	Imperial Valley Solar I LLC	LU	FERC Vol. 10			
13	Kumeyaay Wind LLC	LU	FERC Vol. 10			
14	Maricopa West Solar PV LLC	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.
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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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.

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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	MM Prima Deshecha Energy LLC	LU	FERC Vol. 10			
2	MM San Diego LLC (Miramar RAM)	LU	FERC Vol. 10			
3	Morgan Stanley Capital Group	LU	FERC Vol. 10			
4	Naturener Glacier Wind Energy 1 LLC	EX				
5	Naturener Glacier Wind Energy 2 LLC	EX				
6	Naturener Rim Rock Wind Energy LLC	EX				
7	NLP Valley Center Solar LLC	LU	FERC Vol. 10			
8	NLP Granger A82 LLC	LU	FERC Vol. 10			
9	NRG Solar Borrego LLC	LU	FERC Vol. 10			
10	Oak Creek Wind Power LLC	LU	FERC Vol. 10			
11	Oasis Power Partners LLC	LU	FERC Vol. 10			
12	Ocotillo Express LLC	LU	FERC Vol. 10			
13	Olivenhain Muni Water District	LU	FERC Vol. 10			
14	Orange Grove Energy Center (Tolling)	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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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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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	Otay Landfill Gas LLC	LU	FERC Vol. 10			
2	Otay Mesa Energy Center (Tolling)	LU	FERC Vol. 10			
3	Pacific Wind Lessee LLC	LU	FERC Vol. 10			
4	Pio Pico Energy Center	LU	FERC Vol. 10			
5	San Diego County Water Authority (Hod)	LU	FERC Vol. 10			
6	San Gorgonio Westwinds II LLC	LU	FERC Vol. 10			
7	San Marcos Energy LLC	LU	FERC Vol. 10			
8	SG2 imperial Valley LLC	LU	FERC Vol. 10			
9	Sol Orchard 20 LLC (Ramona 1)	LU	FERC Vol. 10			
10	Sol Orchard 21 LLC (Ramona 2)	LU	FERC Vol. 10			
11	Sol Orchard 22 LLC (Valley Center 1)	LU	FERC Vol. 10			
12	Sol Orchard 23 LLC (Valley Center 2)	LU	FERC Vol. 10			
13	Southern California Edison Company	IF	FERC Vol. 10			
14	Sycamore Energy 1 LLC	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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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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1	Sycamore Energy 2 LLC	LU	FERC Vol. 10			
2	Tallbear Seville LLC	LU	FERC Vol. 10			
3	Yuma Co-generator Association	LU	FERC Vol. 10			
4	BP Energy Company	SF	FERC Vol. 10			
5	EDF Trading North America LLC	SF	FERC Vol. 10			
6	NRG Power Marketing LLC	SF	FERC Vol. 10			
7	Pacific Gas & Electric	SF	FERC Vol. 10			
8	Shell Energy North America (US) LP	SF	FERC Vol. 10			
9	Broker Fees	OS				
10	Hedging Activity	OS				
11	NRG Curtailment Solutions Inc.	OS				
12	ONDA Energy	OS				
13	GHG Allowances	OS				
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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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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	Accrual & Accrual Reversal					
2	Energy Crisis Settlements	OS				
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
369,068			-324,348	43,034,061	1,099,655	43,809,368	1
826,999			18,879,731	25,189,918		44,069,649	2
326,951			34,071	20,066,487	83,532	20,184,090	3
16,898,554				664,077,134	-36,546,156	627,530,978	4
48,079				3,447,336	142,035	3,589,371	5
351,441			19,909	41,429,676	-35,153	41,414,432	6
55,088				4,248,506	-5,555	4,242,951	7
269,219			-47,010	34,932,932	-27,078	34,858,844	8
377,912				48,160,437	3,473,579	51,634,016	9
134,100				16,716,083	1,013,372	17,729,455	10
2,545			23,752	72,718		96,470	11
422			4,402	11,107		15,509	12
21,344			91	1,613,603		1,613,694	13
25,885			185	2,573,437	-2,773	2,570,849	14
26,869,977	1,233,189	1,233,189	233,566,074	1,486,988,004	36,654,290	1,757,208,368	

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)	
12,261			74,625	401,426		476,051	1
317,617			18,045	39,575,350	3,171,489	42,764,884	2
423,037			2,426	42,251,890	2,300,017	44,554,333	3
13,437			446	1,874,383	-1,344	1,873,485	4
13,392			6,950,057	973,877		7,923,934	5
443,867			2,873	46,607,169	-40,404	46,569,638	6
43,862			7,287,812	3,168,811		10,456,623	7
23,866				1,337,151		1,337,151	8
22,339			11,261,009	870,587		12,131,596	9
1,556			7,264	48,024		55,288	10
159,591			-1,223	17,791,505		17,790,282	11
533,627			16,647	60,864,449	2,368,129	63,249,225	12
116,658			48,430	7,020,926		7,069,356	13
47,739			-2,305	3,303,716	-4,774	3,296,637	14
26,869,977	1,233,189	1,233,189	233,566,074	1,486,988,004	36,654,290	1,757,208,368	

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)	
46,345			644	2,831,371		2,832,015	1
31,093			462	2,640,432		2,640,894	2
490,187				34,922,960		34,922,960	3
	287,996	287,996		6,203,232		6,203,232	4
	286,810	286,810		8,777,160		8,777,160	5
	658,383	658,383		28,849,962		28,849,962	6
5,994				660,525	-650	659,875	7
7,729				841,533	-847	840,686	8
69,025			2,565	10,006,550	-6,073	10,003,042	9
5,568			61	372,866	-557	372,370	10
170,131				8,325,609		8,325,609	11
544,029			2,630	56,888,796	155,041	57,046,467	12
594				66,814		66,814	13
43,301			17,122,938	1,903,762		19,026,700	14
26,869,977	1,233,189	1,233,189	233,566,074	1,486,988,004	36,654,290	1,757,208,368	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
38,211				4,072,358		4,072,358	1
2,148,831			70,127,700	71,648,732		141,776,432	2
309,818			3,220	35,774,775	-30,982	35,747,013	3
121,832			45,661,360	6,023,192		51,684,552	4
-26,413			2,646,002	287,775	6,479	2,940,256	5
28,013			220	1,973,374	-2,788	1,970,806	6
12,885			316	1,511,811		1,512,127	7
410,242			60,300	32,747,703	3,247,720	36,055,723	8
4,690			189	608,486	-469	608,206	9
7,482			478	968,184	-747	967,915	10
5,966			28	774,335	-597	773,766	11
11,044			80	1,426,302	-1,104	1,425,278	12
				1,585,705		1,585,705	13
4,031			-598	464,551		463,953	14
26,869,977	1,233,189	1,233,189	233,566,074	1,486,988,004	36,654,290	1,757,208,368	

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)	
12,285			-18,282	1,144,949		1,126,667	1
59,100				4,924,686	367,164	5,291,850	2
13,364			9,982,658	755,156		10,737,814	3
150,144				15,014,400		15,014,400	4
			191,622			191,622	5
			43,427,338			43,427,338	6
			139,554			139,554	7
264,000			-42,300	10,327,259		10,284,959	8
					186,923	186,923	9
					24,799,937	24,799,937	10
					-100,000	-100,000	11
					16,750	16,750	12
					32,095,099	32,095,099	13
							14
26,869,977	1,233,189	1,233,189	233,566,074	1,486,988,004	36,654,290	1,757,208,368	

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
					-1,064,580	-1,064,580	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
26,869,977	1,233,189	1,233,189	233,566,074	1,486,988,004	36,654,290	1,757,208,368	

Schedule Page: 326 Line No.: 1 Column: l

Curtailment of 11,083 MWh and payment/penalties of $1,135,452. Forecasting fees.

Schedule Page: 326 Line No.: 3 Column: l

Manzana - curtailment of 879 MWh and payments of $83,532.

Schedule Page: 326 Line No.: 4 Column: l

CAISO allocated revenues and charges.

Schedule Page: 326 Line No.: 5 Column: l

Curtailment of 2,681 MWh and payment/penalties of $146,560. Forecasting fees.

Schedule Page: 326 Line No.: 6 Column: l

Forecasting fees.

Schedule Page: 326 Line No.: 7 Column: l

Forecasting fees.

Schedule Page: 326 Line No.: 8 Column: l

Forecasting fees.

Schedule Page: 326 Line No.: 9 Column: l

Curtailment of 33,646 MWh and payment/penalties of $3,500,866. Forecasting fees.

Schedule Page: 326 Line No.: 10 Column: l

Curtailment of 10,785 MWh and payment/penalties of $1,025,705. Forecasting fees.

Schedule Page: 326 Line No.: 14 Column: l

Forecasting fees.

Schedule Page: 326.1 Line No.: 2 Column: l

Curtailment of 36,968 MWh and payment/penalties of $3,199,554. Forecasting fees.

Schedule Page: 326.1 Line No.: 3 Column: l

Curtailment of 32,421 MWh and payment/penalties of $2,339,079. Forecasting fees.

Schedule Page: 326.1 Line No.: 4 Column: l

Forecasting fees.

Schedule Page: 326.1 Line No.: 6 Column: l

Forecasting fees.

Schedule Page: 326.1 Line No.: 12 Column: l

Curtailment of 31,286 MWh and payments/penalties of $2,418,298. Forecasting fees.

Schedule Page: 326.1 Line No.: 14 Column: l

Forecasting fees.

Schedule Page: 326.2 Line No.: 7 Column: l

Forecasting fees.

Schedule Page: 326.2 Line No.: 8 Column: l

Forecasting fees.

Schedule Page: 326.2 Line No.: 9 Column: l

Forecasting fees.

Schedule Page: 326.2 Line No.: 10 Column: l

Forecasting fees.

Schedule Page: 326.2 Line No.: 12 Column: l

Curtailment of 2,230 MWh and payments/penalties of $208,856. Forecasting fees.

Schedule Page: 326.3 Line No.: 3 Column: l

Forecasting fees.

Schedule Page: 326.3 Line No.: 5 Column: l

Engineering services.

Schedule Page: 326.3 Line No.: 6 Column: l

Forecasting fees.

Schedule Page: 326.3 Line No.: 8 Column: l

Curtailment of 4,885 MWh and payments/penalties of $3,030,571.

Schedule Page: 326.3 Line No.: 9 Column: l

Forecasting fees.

Schedule Page: 326.3 Line No.: 10 Column: l

Forecasting fees.

Schedule Page: 326.3 Line No.: 11 Column: l

Forecasting fees.

Schedule Page: 326.3 Line No.: 12 Column: l

Forecasting Fees.

Schedule Page: 326.4 Line No.: 2 Column: l

Curtailment of 2,561 MWh and payments/penalties of $372,785. Forecasting fees.

Schedule Page: 326.4 Line No.: 9 Column: l

Contract administration expenses.

Schedule Page: 326.4 Line No.: 10 Column: l

Contract hedging activity.

Schedule Page: 326.4 Line No.: 11 Column: l

NRG forfeited bid fee from the LCR RFO (counterparty default)

Schedule Page: 326.4 Line No.: 12 Column: l

Engineering services.

Schedule Page: 326.4 Line No.: 13 Column: l

Amortization of GHG Allowances

Schedule Page: 326.5 Line No.: 2 Column: l

Settlement amounts received from PG&E and Edison.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.
	201,104,161		201,104,161	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	**201,104,161**	**0**	**201,104,161**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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					
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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) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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)	TRANSFER OF ENERGY: 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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	885,480
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	209,192
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,417,755
6	FERC Audit Adjustments	4,440,369
7	Cost of Financing	280,279
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
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44		
45		
46	TOTAL	7,233,075

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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			24,147,615		24,147,615
2	Steam Production Plant	20,643,761				20,643,761
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	22,106,839			10,453	22,117,292
7	Transmission Plant	135,300,505			1,891,943	137,192,448
8	Distribution Plant	236,625,029			1,912,237	238,537,266
9	Regional Transmission and Market Operation					
10	General Plant	16,052,640				16,052,640
11	Common Plant-Electric	26,691,702		36,395,455		63,087,157
12	TOTAL	457,420,476		60,543,070	3,814,633	521,778,179

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.

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-Desert Star	29,031					
14	311-Palomar	59,382					
15	312-Desert Star	51,804					
16	312-Palomar	106,991					
17	314-Desert Star	14,413					
18	314-Palomar	116,387					
19	315-Desert Star	46,363					
20	315-Palomar	37,254					
21	316-Desert Star	4,723					
22	316-Palomar	43,205					
23	SUBTOTAL	509,553					
24							
25	OTHER PRODUCTION						
26	341-CPEP	1,865					
27	341-Desert Star	1,751					
28	341-Miramar	5,076					
29	341-Palomar	14,201					
30	342-CPEP	600					
31	342-Desert Star	594					
32	342-Miramar	5,233					
33	342-Palomar	14,914					
34	343-CPEP	14,830					
35	343-Desert Star	24,351					
36	343-Miramar	53,362					
37	343-Palomar						
38	344-CPEP	1,973					
39	344-Desert Star	108,119					
40	344-Miramar	19,736					
41	344-Palomar	173,555					
42	344-Solar	53,076					
43	344-Wind	257					
44	345-CPEP	834					
45	345-Desert Star	9,194					
46	345-Miramar	13,457					
47	345-Palomar	6,710					
48	345-Solar	2,316					
49	345-Wind						
50	346-CPEP	1,573					

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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	346-Desert Star	22,342					
13	346-Miramar	3,306					
14	346-Palomar	1					
15	SUBTOTAL	553,226					
16							
17	TRANSMISSION-SWPL						
18	352	14,692					
19	353	252,117					
20	354	62,000					
21	355	10,264					
22	356	46,249					
23	359	5,324					
24	SUBTOTAL	390,646					
25							
26	TRANSMISSION-SRPL						
27	352	121,021					
28	353	161,732					
29	354	766,327					
30	355	3,344					
31	356	173,392					
32	357	80,502					
33	358	126,452					
34	359	227,676					
35	SUBTOTAL	1,660,446					
36							
37	TRANSMISSION-OTHER						
38	352	351,760					
39	353	1,072,625					
40	353.4	1,420					
41	354	67,059					
42	355	476,821					
43	356	369,141					
44	357	277,413					
45	358	250,560					
46	359	79,553					
47	SUBTOTAL	2,946,352					
48							
49	DISTRIBUTION						
50	361	4,652					

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	362.1	504,967					
13	363	101,188					
14	364	690,844					
15	365	644,030					
16	366	1,204,734					
17	367	1,507,073					
18	368.1	609,844					
19	368.2	35,400					
20	369.1	153,665					
21	369.2	347,011					
22	370.1	3,912					
23	370.11	188,455					
24	E370.20	5,437					
25	E370.21	50,703					
26	E371.00	8,938					
27	E373.20	14,999					
28	SUBTOTAL	6,075,852					
29							
30	GENERAL						
31	390	38,069					
32	392.2	58					
33	393.1	6					
34	394.11	26,956					
35	394.2	318					
36	395.1	5,152					
37	397.1	256,160					
38	397.2	7,445					
39	397.6	14,036					
40	397.7	65					
41	398.1	6,976					
42	398.2	111					
43	SUBTOTAL	355,352					
44							
45	TOTAL	12,491,427					
46							
47	SEE FOOTNOTE						
48							
49							
50							

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

Reclassification of 2017 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	-	24,147,615	-	24,147,615
Steam Production	21,122,909	-	-	21,122,909
Nuclear Production	-	-	-	-
Other Production	20,420,037	-	10,453	20,430,490
Transmission Plant	133,723,709	-	1,882,332	135,606,041
Distribution Plant	239,409,479	-	1,921,848	241,331,327
General Plant	16,052,640	-	-	16,052,640
Common Plant-Electric	26,691,702	36,395,455	-	63,087,157
Total Ratemaking Depreciation & Amort.	457,420,476	60,543,070	3,814,633	521,778,179

Schedule Page: 336.2 Line No.: 47 Column: b

Depreciable Plant Base (In Thousands) shown as weighted plant calculated through the quotient of depreciation expense, inclusive of Net Salvage, and annual depreciation rate.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	D. 16-12-019 DISTRIBUTED GENERATION		1,003	1,003	
2			118	118	
3					
4	D. 16-12-022 PIPELINE SAFETY		30,756	30,756	
5			3,619	3,619	
6					
7	D. 16-12-023 SAFETY MODEL ASSESSMENT		4,565	4,565	
8			537	537	
9					
10	D. 16-12-056 NUCLEAR GENERATION		17,254	17,254	
11			2,836	2,836	
12					
13	D. 16-12-061 SAFETY MODEL ASSESSMENT		20,099	20,099	
14			2,365	2,365	
15					
16	D. 16-12-062 SAFETY MODEL ASSESSMENT		8,931	8,931	
17			1,051	1,051	
18					
19	D. 17-01-017 SAN ONOFRE NUCLEAR GEN STATION		13,106	13,106	
20			2,154	2,154	
21					
22	D. 17-01-019 CALIFORNIA ENERGY STORAGE		3,809	3,809	
23			448	448	
24					
25	D. 17-01-020 DEMAND RESPONSE		924	924	
26					
27	D. 17-01-021 DEMAND RESPONSE		3,014	3,014	
28					
29	D. 17-01-026 ENERGY EFFICIENCY PROGRAMS		1,995	1,995	
30			235	235	
31					
32	D. 17-01-027 SAN ONOFRE NUCLEAR GEN STATION		41,276	41,276	
33					
34	D. 17-01-028 SAN ONOFRE NUCLEAR GEN STATION		18,671	18,671	
35					
36	D. 17-01-029 SOLAR GENERATED ELEC ACCESS		8,862	8,862	
37					
38	D. 17-01-030 RESIDENTIAL RATE STRUCTURES		70,152	70,152	
39			9,312	9,312	
40					
41	D. 17-02-013 NATURAL GAS RATES		17,830	17,830	
42					
43	D. 17-02-014 WATER-ENERGY NEXUS PROGRAMS		2,867	2,867	
44			337	337	
45					
46	TOTAL	8,943,258	13,761,600	22,704,858	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	D. 17-03-006 CALIFORNIA ALTERNATE RATES PROG		10,439	10,439	
2			1,228	1,228	
3					
4	D. 17-03-007 CALIFORNIA RENEWABLES		18,375	18,375	
5					
6	D. 17-03-008 DEMAND RESPONSE		8,173	8,173	
7					
8	D. 17-03-009 STATEWIDE OUTREACH PROGRAM		5,414	5,414	
9			637	637	
10					
11	D. 17-03-010 DEMAND RESPONSE		1,938	1,938	
12					
13	D. 17-03-011 STATEWIDE OUTREACH PROGRAM		5,398	5,398	
14			635	635	
15					
16	D. 17-03-022 CALIFORNIA ALTERNATE RATES PROG		18,882	18,882	
17			2,222	2,222	
18					
19	D. 17-03-023 CALIFORNIA ALTERNATE RATES PROG		1,267	1,267	
20			149	149	
21					
22	D. 17-03-024 CALIFORNIA ALTERNATE RATES PROG		15,334	15,334	
23			1,804	1,804	
24					
25	D. 17-03-025 CALIFORNIA ALTERNATE RATES PROG		12,122	12,122	
26			1,426	1,426	
27					
28	D. 17-04-010 ALTERNATE FUEL VEHICLE		1,951	1,951	
29			230	230	
30					
31	D. 17-04-012 PIPELINE SAFETY AND RELIABILITY		16,640	16,640	
32					
33	D. 17-04-031 CALIFORNIA RENEWABLES		1,788	1,788	
34					
35	D. 17-04-034 DISTRIBUTED ENERGY RESOURCES		11,580	11,580	
36			1,607	1,607	
37					
38	D. 17-04-036 DISTRIBUTED ENERGY RESOURCES		2,145	2,145	
39			298	298	
40					
41	D. 17-04-037 SOUTH ORANGE COUNTY RELIABILITY		179,376	179,376	
42					
43	D. 17-04-038 WATER-ENERGY NEXUS PROGRAMS		3,258	3,258	
44			452	452	
45					
46	TOTAL	8,943,258	13,761,600	22,704,858	

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	D. 17-05-009 CALIFORNIA ALTERNATE RATES PROG		6,408	6,408	
2			754	754	
3					
4	D. 17-08-010 DISTRIBUTION RESOURCES PLANS		15,481	15,481	
5					
6	D. 17-08-011 ENERGY EFFICIENCY INCENTIVES		9,884	9,884	
7			1,372	1,372	
8					
9	D. 17-09-012 INTERCONNECTION RULES		3,774	3,774	
10					
11	D. 17-09-014 CALIFORNIA ENERGY STORAGE		3,993	3,993	
12			554	554	
13					
14	D. 17-09-033 RESIDENTIAL RATE STRUCTURES		9,229	9,229	
15			1,517	1,517	
16					
17	CALIFORNIA PUBLIC UTILITIES COMMISSION FEES	8,069,991		8,069,991	
18		873,267		873,267	
19					
20	FERC PROCEEDINGS		2,644	2,644	
21					
22					
23	SETTLEMENT REFUND LITIGATION RESOLUTION		28,358	28,358	
24					
25	MISCELLANEOUS		9,710,504	9,710,504	
26			3,354,234	3,354,234	
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	8,943,258	13,761,600	22,704,858	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	1,003					1
gas	928	118					2
							3
elec	928	30,756					4
gas	928	3,619					5
							6
elec	928	4,565					7
gas	928	537					8
							9
elec	928	17,254					10
gas	928	2,836					11
							12
elec	928	20,099					13
gas	928	2,365					14
							15
elec	928	8,931					16
gas	928	1,051					17
							18
elec	928	13,106					19
gas	928	2,154					20
							21
elec	928	3,809					22
gas	928	448					23
							24
elec	928	924					25
							26
elec	928	3,014					27
							28
elec	928	1,995					29
gas	928	235					30
							31
elec	928	41,276					32
							33
elec	928	18,671					34
							35
elec	928	8,862					36
							37
elec	928	70,152					38
gas	928	9,312					39
							40
gas	928	17,830					41
							42
elec	928	2,867					43
gas	928	337					44
							45
		22,704,858					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	10,439					1
gas	928	1,228					2
							3
elec	928	18,375					4
							5
elec	928	8,173					6
							7
elec	928	5,414					8
gas	928	637					9
							10
elec	928	1,938					11
							12
elec	928	5,398					13
gas	928	635					14
							15
elec	928	18,882					16
gas	928	2,222					17
							18
elec	928	1,267					19
gas	928	149					20
							21
elec	928	15,334					22
gas	928	1,804					23
							24
elec	928	12,122					25
gas	928	1,426					26
							27
elec	928	1,951					28
gas	928	230					29
							30
gas	928	16,640					31
							32
elec	928	1,788					33
							34
elec	928	11,580					35
gas	928	1,607					36
							37
elec	928	2,145					38
gas	928	298					39
							40
elec	928	179,376					41
							42
elec	928	3,258					43
gas	928	452					44
							45
		22,704,858					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	6,408					1
gas	928	754					2
							3
elec	928	15,481					4
							5
elec	928	9,884					6
gas	928	1,372					7
							8
elec	928	3,774					9
							10
elec	928	3,993					11
gas	928	554					12
							13
elec	928	9,229					14
gas	928	1,517					15
							16
elec	928	8,069,991					17
gas	928	873,267					18
							19
elec	928	2,644					20
							21
							22
elec	928	28,358					23
							24
elec	928	9,710,504					25
gas	928	3,354,234					26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		22,704,858					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	
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	
16		
17	B. External	
18		
19	(1) Research Support to the Electrical	Collaborative Memberships
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		

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)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
13,066,068		588	13,066,068		9
					10
					11
					12
					13
					14
13,066,068			13,066,068		15
					16
					17
					18
	824,594	588	824,594		19
	5,498	408	5,498		20
					21
					22
					23
					24
					25
					26
	10,864,929	588	10,864,929		27
	74,086	408	74,086		28
	11,769,107		11,769,107		29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	10,068,684		
4	Transmission	11,371,160		
5	Regional Market			
6	Distribution	34,974,680		
7	Customer Accounts	15,555,232		
8	Customer Service and Informational	20,092,530		
9	Sales			
10	Administrative and General	38,571,065		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	130,633,351		
12	Maintenance			
13	Production	1,583,174		
14	Transmission	10,505,656		
15	Regional Market			
16	Distribution	14,610,153		
17	Administrative and General	1,264,195		
18	TOTAL Maintenance (Total of lines 13 thru 17)	27,963,178		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,651,858		
21	Transmission (Enter Total of lines 4 and 14)	21,876,816		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	49,584,833		
24	Customer Accounts (Transcribe from line 7)	15,555,232		
25	Customer Service and Informational (Transcribe from line 8)	20,092,530		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	39,835,260		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	158,596,529	47,232,920	205,829,449
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	80,672		
35	Transmission	2,200,430		
36	Distribution	21,173,874		
37	Customer Accounts	7,618,449		
38	Customer Service and Informational	2,241,568		
39	Sales			
40	Administrative and General	13,323,016		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	46,638,009		
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	3,430,089		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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	6,049,537		
49	Administrative and General	429,896		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	9,909,522		
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	80,672		
56	Transmission (Lines 35 and 47)	5,630,519		
57	Distribution (Lines 36 and 48)	27,223,411		
58	Customer Accounts (Line 37)	7,618,449		
59	Customer Service and Informational (Line 38)	2,241,568		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	13,752,912		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	56,547,531	14,667,145	71,214,676
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	215,144,060	61,900,065	277,044,125
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	65,915,788	108,106,118	174,021,906
69	Gas Plant	14,114,349	17,929,020	32,043,369
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	80,030,137	126,035,138	206,065,275
72	Plant Removal (By Utility Departments)			
73	Electric Plant	7,520,085	9,998,664	17,518,749
74	Gas Plant	633,522	594,349	1,227,871
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,153,607	10,593,013	18,746,620
77	Other Accounts (Specify, provide details in footnote):			
78	3rd PArty Billings, Gas		1,618,945	1,618,945
79	3rd Party Billings, Electric		5,478,555	5,478,555
80	Affiliate Billings, Gas		8,746,596	8,746,596
81	Affiliate Billings, Electric		25,715,956	25,715,956
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts		41,560,052	41,560,052
96	TOTAL SALARIES AND WAGES	303,327,804	240,088,268	543,416,072

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

FERC 426 is not included in the detail classification lines or summary totals.
FERC 426 for 2017 amounts to $1,012,380

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	394,023,164	48,206,049				442,229,213
389 Land & Land Rights	8,026,299	325,243				8,351,542
390 Structures & Improvements	348,570,445	48,317,783	9,447,756		(1,525,680)	385,914,792
391 Office Furniture & Equipment	82,003,241	19,754,597	28,710,142			73,047,696
392 Transportation Equipment	420,462	140,073	46,138			514,397
393 Stores Equipment	58,941	322,411	35,970			345,382
394 Tools, Shop & Garage Equip.	3,049,856	296,766	76,067			3,270,555
395 Laboratory Equipment	2,095,455		170,084			1,925,371
396 Power Operated Equipmennt						
397 Communication Equipment	188,234,125	788,709	22,510,071			166,512,763
398 Miscellaneous Equipment	2,446,629	29,009	237,355			2,238,283
FIN 47 ARC - Common	4,307,504					4,307,504
Fleet Capital Lease	20,730,793	1,315,532	3,813			22,042,512
TOTAL COMMON PLANT	1,053,966,914	119,496,172	61,237,396		(1,525,680)	1,110,700,010
Construction Work in Progress	126,503,879	117,562,948				244,066,827
TOTAL COMMON PLANT	1,180,470,793	237,059,120	61,237,396		(1,525,680)	1,354,766,837

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, 2017 Accumulated Depreciation
303 Misc. Intangible Plant	301,666,818
389 Land & Land Rights	27,774
390 Structures & Improvements	157,326,661
391 Office Furniture & Equipment	26,110,132
392 Transportation Equipment	(248,148)
393 Stores Equipment	15,131
394 Tools, Shop & Garage Equipment	829,298
395 Laboratory Equipment	904,515
396 Power Operated Equipment	(192,979)
397 Communication Equipment	66,638,766
398 Miscellaneous Equipment	390,975
108.4 Retirement Work in Progress	
FIN 47 Accumulated Depreciation	2,702,642
Fleet Capital Lease	21,123,899
Total Accumulated Depreciation	577,295,484

Split of Common Utility Plant to Departments: (excluding CWIP) (see Note 2- Page 356.2)

		December 31,2017 Balance End of Year	Accumulated Depreciation
Electric	74.62%	828,804,347	430,777,890
Gas	25.38%	281,895,663	146,517,594
Total	100.00%	1,110,700,010	577,295,484

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		48,774,399
389	Land & Land Rights		(3)
390	Structures & Improvements		12,467,832
391	Office Furniture & Equipment		9,166,281
392	Transportation Equipment		86,799
393	Stores Equipment		5,499
394	Tools, Shop & Garage Equipment		176,344
395	Laboratory Equipment		88,658
396	Power Operated Equipment		
397	Communication Equipment		13,612,510
398	Miscellaneous Equipment		166,248
	Total		84,544,567

(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 2016-2017 and 2017-2018. 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 adopted by the California Public Utilities Commission. These rates were revised in January 2017.
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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)	126,561,972	248,463,892	474,788,644	664,077,134
3	Net Sales (Account 447)	(80,070,963)	(185,040,164)	(385,568,705)	(504,277,729)
4	Transmission Rights				
5	Ancillary Services	474,910	1,241,284	2,918,811	3,629,618
6	Other Items (list separately)				
7	Congestion	266,518	1,182,244	1,727,735	1,727,735
8	CCR (Congestion Revenue Rights)	(8,931,285)	(14,320,168)	(25,698,229)	(43,051,551)
9	GMC (Grid Management Charges)	2,615,176	5,188,101	8,764,816	11,451,198
10	Other	1,188,184	2,136,228	562,814	(3,810,983)
11	UFE (Unacconted for Energy)	2,473,277	5,305,406	5,440,514	5,440,514
12					
13					
14					
15					
16					
17					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	44,577,789	64,156,823	82,936,400	135,185,936

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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year – Usage - Related Billing Determinant – Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year – Usage - Related Billing Determinant – Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	1,306,742	MHW	11,186,436	1,392,268	MWH	7,556,818
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)	1,306,742		11,186,436	1,392,268		7,556,818

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	3,098	23	17	3,098					
2	February	3,028	27	18	3,028					
3	March	2,826	6	18	2,826					
4	Total for Quarter 1				8,952					
5	April	2,757	5	18	2,757					
6	May	2,917	22	19	2,917					
7	June	3,769	26	16	3,769					
8	Total for Quarter 2				9,443					
9	July	3,736	10	16	3,736					
10	August	4,355	30	15	4,355					
11	September	4,544	1	15	4,544					
12	Total for Quarter 3				12,635					
13	October	4,371	24	16	4,371					
14	November	3,223	22	18	3,223					
15	December	3,046	11	18	3,046					
16	Total for Quarter 4				10,640					
17	Total Year to Date/Year				41,670					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	15,623,082
3	Steam	3,570,759			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	13,677,887
7	Other	121,452			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	3,692,211	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	34,006
10	Purchases	26,869,977	27	Total Energy Losses	1,227,213
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	30,562,188
12	Received	1,233,189			
13	Delivered	1,233,189			
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)	30,562,188			

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 10/26/2018	Year/Period of Report End of 2017/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:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,338,224	823,883	3,098	23	17
30	February	1,188,364	1,028,204	3,028	27	18
31	March	1,238,097	820,700	2,826	6	18
32	April	1,159,937	912,780	2,757	5	18
33	May	1,156,664	995,295	2,917	22	19
34	June	1,248,126	1,464,253	3,769	26	16
35	July	1,442,799	1,227,390	3,736	10	16
36	August	1,477,088	2,012,163	4,355	30	15
37	September	1,526,114	1,612,294	4,544	1	15
38	October	1,323,500	1,176,291	4,371	24	16
39	November	1,268,028	986,497	3,223	22	18
40	December	1,256,141	618,137	3,046	11	18
41	TOTAL	15,623,082	13,677,887			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)	566.00			96.00		
6	Net Peak Demand on Plant - MW (60 minutes)	566			96		
7	Plant Hours Connected to Load	6058			1663		
8	Net Continuous Plant Capability (Megawatts)	566			96		
9	When Not Limited by Condenser Water	566			96		
10	When Limited by Condenser Water	0			96		
11	Average Number of Employees	29			3		
12	Net Generation, Exclusive of Plant Use - KWh	2517592000			112099000		
13	Cost of Plant: Land and Land Rights	14480000			0		
14	Structures and Improvements	75799052			5075863		
15	Equipment Costs	510206496			96878565		
16	Asset Retirement Costs	0			0		
17	Total Cost	600485548			101954428		
18	Cost per KW of Installed Capacity (line 17/5) Including	1060.9285			1062.0253		
19	Production Expenses: Oper, Supv, & Engr	1327801			2992		
20	Fuel	74461384			4596702		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4823889			64330		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3390271			334101		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	235			0		
30	Maintenance of Structures	141277			785		
31	Maintenance of Boiler (or reactor) Plant	909440			0		
32	Maintenance of Electric Plant	4219617			1632884		
33	Maintenance of Misc Steam (or Nuclear) Plant	5120110			868		
34	Total Production Expenses	94394024			6632662		
35	Expenses per Net KWh	0.0375			0.0592		
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	17543651	0	0	1055851	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	4.244	0.000	0.000	4.354	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.153	0.000	0.000	4.260	0.000	4.066
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	0.000	0.041	0.000	0.000
44	Average BTU per KWh Net Generation	7157.000	0.000	0.000	9673.000	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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	213	0	7
450	47	0	8
450	47	0	9
450	47	0	10
23	1	0	11
1055077010	8536000	0	12
0	0	0	13
30877505	1865081	0	14
300290113	24209294	0	15
109537	0	0	16
331277155	26074375	0	17
618.0544	554.7739	0	18
846982	0	0	19
32985910	508922	0	20
0	0	0	21
1742141	7697	0	22
0	0	0	23
0	0	0	24
843507	186353	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	13683	0	30
2184043	0	0	31
7554946	523092	0	32
1327262	1079	0	33
47484791	1240826	0	34
0.0450	0.1454	0.0000	35

(d)			(e)			(f)			Line No.
GAS			GAS						36
MCF			MCF						37
7938511	0	0	96596	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
4.155	0.000	0.000	5.269	0.000	0.000	0.000	0.000	0.000	41
4.066	0.000	0.000	5.155	0.000	0.000	0.000	0.000	0.000	42
0.031	0.000	0.000	0.060	0.000	0.000	0.000	0.000	0.000	43
7727.000	0.000	0.000	11622.000	0.000	0.000	0.000	0.000	0.000	44

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

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San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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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			21
			22
			23
			24
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			30
			31
			32
			33
			34
			35
			36
			37
			38

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	820	3,002,210
2						
3						
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8						
9						
10						
11						
12						
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14						
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.
7,505,525		50,670		Gas	565	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.
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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	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 Mi					368.60		9
11	San Luis Rey Tap		230.00	230.00	3		5.29	2
12			230.00	230.00	3	26.45		2
13		Mission	230.00	230.00	2W	3.26		1
14	San Luis Rey		230.00	230.00	3	0.11		1
15			230.00	230.00	2S	0.49		2
16			230.00	230.00	2W	1.00		1
17		San Onofre	230.00	230.00	3	16.26		2
18	San Luis Rey		230.00	230.00	3	5.75		1
19		Encina	230.00	230.00	3	1.47		1
20	San Luis Rey		230.00	230.00	2W	2.34		1
21			230.00	230.00	3		26.58	2
22		Mission	230.00	230.00	2W		3.26	1
23	San Luis Rey		230.00	230.00	3	18.12		2
24		San Onofre	230.00	230.00	1S		0.07	
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	1,690.09	439.09	457

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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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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.
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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			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	9.30		1
11		Old Town	230.00	230.00	1S	2.33		1
12	Palomar		230.00	230.00	1S		0.16	1
13		Escondido	230.00	230.00	1S		0.22	1
14	Palomar Generation		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	Miguel		230.00	230.00	1S		1.59	2
22			230.00	230.00	3	1.97		1
23		Mission	230.00	230.00	1S	6.70		1
24	Miguel		230.00	230.00	3	7.52		1
25			230.00	230.00	1S	14.78		1
26		Mission	230.00	230.00	3	9.11		1
27			230.00	230.00	3	0.45		1
28			230.00	230.00	1S	1.59		1
29	Old Town	Mission	230.00	230.00	1S	3.86		2
30	Old Town	Mission	230.00	230.00	1S		3.85	2
31	Silvergate		230.00	230.00	4	0.69		1
32			230.00	230.00	4	0.31		1
33			230.00	230.00	4	5.04		1
34			230.00	230.00	4	0.26		1
35		Old Town	230.00	230.00	4	0.99		1
36					TOTAL	1,690.09	439.09	457

TRANSMISSION LINE STATISTICS

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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	Silvergate		230.00	230.00	4	0.69		1
2			230.00	230.00	4	0.31		1
3			230.00	230.00	4	5.04		1
4			230.00	230.00	4	0.26		1
5		Old Town	230.00	230.00	4	0.99		1
6	Escondido		230.00	230.00	1S	5.02		1
7		Talega	230.00	230.00	3	46.03		1
8	Otay Mesa		230.00	230.00	1S	0.10		1
9		Tijuana	230.00	230.00	3	1.61		1
10	Otay Mesa	Miguel	230.00	230.00	3,1S		8.92	2
11	Miguel		230.00	230.00	1S		24.61	2
12			230.00	230.00	3		0.67	2
13		Sycamore	230.00	230.00	3		3.62	2
14	Otay Mesa	Miguel	230.00	230.00	3,1S		8.92	2
15	Miguel	Bay Blvd	230.00	230.00	1S	9.59	9.59	2
16	Bay Blvd		230.00	230.00	4	2.26		1
17			230.00	230.00	4	0.76		1
18			230.00	230.00	4	0.03		1
19			230.00	230.00	3		3.85	1
20		Silvergate	230.00	230.00	4	0.40		1
21	Imperial Valley		230.00	230.00	1S	0.04		1
22		IV Gen 3	230.00	230.00	1S	1.36		1
23	Imperial Valley		230.00	230.00	1S		0.55	2
24			230.00	230.00	2S		0.09	2
25		La Rosita	230.00	230.00	3		5.11	2
26	Palomar		230.00	230.00	1S		0.80	1
27			230.00	230.00	3		5.96	2
28			230.00	230.00	3	10.12		1
29			230.00	230.00	1S	4.75		1
30			230.00	230.00	3	1.55		1
31		Syamore Canyon	230.00	230.00	1S	0.17		1
32	San Onofre		230.00	230.00	2S		0.47	2
33	San Onofre	Talega	230.00	230.00	3		6.43	1
34	Penasquitos		230.00	230.00	1S		10.04	2
35		Encina	230.00	230.00	3		8.09	2
36					TOTAL	1,690.09	439.09	457

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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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	Sycamore Canyon	Suncrest	230.00	230.00	3	21.77		2
2	Sycamore Canyon	Suncrest	230.00	230.00	3	21.77		2
3	Imperial Valley		230.00	230.00	1S		2.88	2
4			230.00	230.00	2S		0.09	2
5		Drew Switchyard	230.00	230.00	3		2.35	2
6	Drew Switchyard		230.00	230.00	1S	1.10		1
7		DW Gen 1	230.00	230.00	1S	0.12		1
8	Drew Switchyard	DW Gen 3	230.00	230.00	1S	1.39		1
9	Pio Pico Generator	Otay Mesa Sy	230.00	230.00	1S	0.04		1
10	San Luis Rey		230.00	230.00	1S		0.09	2
11		GIS Terminal	230.00	230.00	4		0.10	2
12	San Luis Rey		230.00	230.00	1S		0.09	2
13		GIS Terminal	230.00	230.00	4		0.09	2
14	Imperial Valley	Phase Shifting Trans	230.00	230.00	1S		0.17	2
15	Z172244	Z172242	230.00	230.00	1S		0.07	
16	Z189533	Z189535	230.00	230.00	3	0.27		
17	East County	Eco Gen 1	230.00	230.00	3		0.15	
18	Drew Switchyard		230.00	230.00	1S		2.39	2
19		Z46503	230.00	230.00	3		2.71	2
20	Total 230kV Pole Line Mi					314.51	227.05	165
21	Encina		138.00	230.00	1S	0.05		2
22		Cannon	138.00	230.00	1S	0.08		2
23	Encina		138.00	138.00	1S	0.63		2
24			138.00	138.00	3	0.70		2
25			138.00	138.00	2W	19.58		1
26			138.00	138.00	4	0.60		1
27		Penasquitos	138.00	138.00	3	1.64		1
28	Palomar		138.00	138.00	1S	0.23		1
29			138.00	138.00	4	0.71		1
30		Batiquitos	138.00	138.00	1S		1.81	2
31	Encina		138.00	138.00	1S	0.02		1
32			138.00	138.00	1S		2.00	2
33			138.00	138.00	3		0.01	2
34		Palomar	138.00	138.00	1S		1.05	2
35	Telegraph Canyon	Proctor Valley	138.00	230.00	1S	2.60		2
36					TOTAL	1,690.09	439.09	457

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/Q4

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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	Friars		138.00	138.00	4	0.16		1
2			138.00	230.00	1S	1.82		2
3		Doublet Tap	138.00	230.00	3		10.22	2
4	Doublet Tap	Doublet Substation	138.00	138.00	1S,1W	1.81		2
5	Doublet Tap	Penaquitos	138.00	138.00	3		0.70	2
6	Chicarita		138.00	138.00	3,1S,1W		10.89	1
7			138.00	138.00	3,1S		0.96	2
8		Shadowridge	138.00	138.00	1S		3.74	2
9			138.00	138.00	1W,1S	0.41		1
10		NC Metering	138.00	138.00	1W	0.39		1
11	Telegraph Canyon		138.00	138.00	3	0.05		1
12			138.00	138.00	3		6.70	2
13			138.00	138.00	4	2.44		1
14			138.00	138.00	3		6.43	1
15			138.00	138.00	3		6.43	1
16			138.00	138.00	3,1W	0.08		3
17			138.00	138.00	1W,1S		1.23	3
18		Grant Hill	138.00	138.00	4	0.86		1
19	Capistrano		138.00	138.00	3,1S,W	0.10	1.55	1
20		Pico	138.00	138.00	3,1S		4.82	1
21	Santee		138.00	138.00	1W,1S	2.35		1
22			138.00	138.00	1S	4.24		2
23			138.00	138.00	3,1S	0.34		1
24		Los Coches	138.00	138.00	3	0.04		1
25	Sycamore		138.00	138.00	1W	5.71		1
26		Chicarita	138.00	138.00	4	0.06		1
27	Sycamore		138.00	138.00	1S		6.63	2
28		Santee	138.00	138.00	1W	1.56		1
29	Mission		138.00	138.00	2W		0.20	1
30			138.00	138.00	3,1S		1.69	2
31		(Tower Z874970)	138.00	138.00	3	1.69	8.00	2
32	(Tower Z874970)	Carlton Hills	138.00	138.00	3,1S		1.44	2
33	Telegraph Canyon	Miguel 60 Tap	138.00	138.00	3		3.11	2
34	Miguel 60 Tap		138.00	138.00	3		0.69	2
35		Miguel	138.00	138.00	3		0.02	2
36					TOTAL	1,690.09	439.09	457

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Miguel 60 Tap	Los Coches	138.00	138.00	3		12.43	2
2	North City Mtr Tap	Meadowlark Tap	138.00	138.00	3		7.40	2
3	Batiquitos	Meadowlark Tap	138.00	138.00	1S	2.58		2
4	Chicarita	Meadowlark Tap	138.00	138.00	2W	12.04		1
5	Shadowridge	Meadowlark Tap	138.00	138.00	3,1W	3.99		2
6	Miguel		138.00	138.00	3	1.29		2
7		Protor Valley	138.00	138.00	1W	0.05		1
8	Friars		138.00	138.00	4	0.10		
9		Mission	138.00	230.00	1S,3	1.22		2
10	Sycamore		138.00	138.00	1S	4.06	4.06	2
11		Carlton Hills	138.00	138.00	1S,3	1.81	1.44	2
12	Margarita		138.00	138.00	3	1.22		2
13			138.00	230.00	1S	0.78		1
14		Trabuco	138.00	138.00	4	3.32		1
15	Talega	Rancho Mission Viejo	138.00	138.00	1S,1W	7.74		1
16	Trabuco		138.00	138.00	1W	3.80		1
17			138.00	138.00	1S,3		6.50	2
18			138.00	138.00	4	0.33		1
19		Pico	138.00	138.00	3	3.49		2
20	Trabuco		138.00	138.00	1W	3.70		1
21			138.00	138.00	1W	0.01		1
22		Capistrano	138.00	138.00	1W	0.02		1
23	San Mateo	San Mateo Tap	138.00	138.00	1W	0.66		1
24	San Mateo Tap	Z203020	138.00	138.00	3,1W		7.08	2
25	Z203020	Z203021	138.00	138.00	4	0.33		1
26	Z203021	Z196606	138.00	138.00	1S	0.25		1
27	Z196606	Z248108	138.00	138.00	1W,2W,1S,3	6.74		1
28	Z248108	Laguna Niguel	138.00	138.00	4	1.85		1
29	Talega Tap	Talega	138.00	138.00	1W	0.36		1
30	Pico		138.00	138.00	3,1S		0.68	2
31		Talega	138.00	138.00	1W,S	0.11	0.41	1
32	Capistrano		138.00	138.00	1W	0.01		1
33			138.00	138.00	1W,1S	1.38		1
34		Laguna Niguel	138.00	138.00	4	1.82		
35	Rancho Mission Viejo	Margarita	138.00	138.00	1W,S	1.30		1
36					TOTAL	1,690.09	439.09	457

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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 Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Mission		138.00	138.00	1S,W	2.94		2
2		Grant Hill	138.00	138.00	4	2.84		1
3	Encina	Encina Hub	138.00	138.00	1S	1.28	1.28	1
4	Encina Hub	Shadowridge	138.00	138.00	2W	6.72		1
5	East County	Boulevard East	138.00	138.00	1S	6.97		1
6	East County	Boulevard East	138.00	138.00	4	5.60		1
7	East County	Boulevard East	138.00	138.00	4	1.12		1
8	East County	Boulevard East	138.00	138.00	4	0.18		1
9	Pico		138.00	138.00	3,1S	0.90		2
10		Talega	138.00	138.00	1W	0.36		1
11			138.00	138.00	3		2.85	2
12		San Mateo	138.00	138.00	1W	0.60		1
13	Encina		138.00	230.00	1S		0.05	2
14	Pole #124528	Cannon	138.00	230.00	1S		0.08	2
15	East County	Eco Gen #2	138.00	138.00	1S	0.33		1
16	13822	De-Energized	138.00	138.00	2W	0.06		1
17	13832	De-Energized	138.00	138.00	3,1S,1W	3.36		1
18	13832	De-Energized	138.00	138.00	3,1S,1W	3.21		1
19	13811	De-Energized	138.00	138.00	1S	1.07		1
20	13811	De-Energized	138.00	138.00	3	5.69		1
21	Cannon	Encina Hub	138.00	138.00	1S		1.27	2
22	Encina Hub	Calavera Tap	138.00	138.00	2W	0.39		1
23	Encina Hub	Calavera Tap	138.00	138.00	2W	2.94		1
24	Calavera Tap	San Luis Rey	138.00	138.00	2W	3.89		1
25	Bay Blvd		138.00	138.00	3		2.95	2
26		Telegraph Canyon					3.75	2
27	Total 138kV Pole Line Mi					167.76	132.55	158
28					1W	706.78	25.40	125
29					2W	7.11	1.38	
30					1S	43.23	1.50	
31					3	20.00	50.61	
32					4	62.10	0.60	
33	Total of 69kV Pole Line Mi					839.22	79.49	125
34								
35								
36					TOTAL	1,690.09	439.09	457

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	10/26/2018	End of 2017/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	Cost of Line							
2	Expenses, Except ISO Charge							
3	ISO Charges							
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					TOTAL	1,690.09	439.09	457

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)	
2-2156 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
1033.5 ACSR								11
1033.5 ACSR								12
1033.5 ACSR								13
1033.5 ACSR								14
2-1033.5 ACSR								15
1033.5 ACSR								16
1033.5 ACSR								17
2-1033.5 ACSR								18
2-1109 ACAR								19
1033.5 ACSR								20
1033.5 ACSR								21
1033.5 ACSR								22
1033.5 ACSR								23
2-1033.5 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 ACSR								32
2-1033.5 ACSR								33
2-1109 ACAR								34
2-1109 ACAR								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-1109 ACAR								1
2-1109 ACAR								2
2-900 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
2-900 ACSS								12
2-605 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
2-1033.5 ACSR								21
2-1109 ACAR								22
2-1109 ACAR								23
1109 ACAR								24
636 ACSS								25
605 ACSS								26
1033.5 ACSR								27
1033.5 ACSR								28
1109 ACAR								29
1109 ACAR								30
1-3500 KCMIL CU								31
1-2500 KCMIL CU								32
1-3500 KCMIL CU								33
1-2500 KCMIL CU								34
1-3500 KCMIL CU								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)
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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)	
1-3500 KCMIL CU								1
1-2500 KCMIL CU								2
1-3500 KCMIL CU								3
1-2500 KCMIL CU								4
1-3500 KCMIL CU								5
1033.5 ACSR								6
1033.5 ACSR								7
2-900 ACSS								8
2-1033.5 ACSR								9
2-900 ACSS								10
2-1033.5 ACSR								11
2-605 ACSR								12
2-1109 ACAR								13
2-900 ACSS								14
2-900 ACSS								15
2-3500 KCMIL CU								16
2-4000 KCMIL								17
2-3500 KCMIL CU								18
1-900 ACSS								19
2-3500 KCMIL CU								20
2-1033.5 ACSS/AW								21
2-1033.5 ACSS/AW								22
2-900 ACSS/AW								23
2-900 ACSS/AW								24
2-900 ACSS/AW								25
2-900 ACSS								26
2-1109 ACAR								27
2-1109 ACAR								28
2-1109 ACAR								29
2-1109 ACAR								30
2-1033.5 ACSR								31
2-1033.5 ACSR								32
1033.5 ACSR								33
1109-ACAR								34
1033.5 ACSR								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	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)	
900 ACSS								1
900 ACSS								2
2-900 ACSS/AW								3
2-900 ACSS/AW								4
2-900 ACSS/AW								5
2-900 ACSS								6
2-636 ACSS								7
1-900 ACSS								8
1-1272 ACSS								9
2-1033.5 ACSR/AW								10
1-5000 KCMIL CU								11
2-1033.5 ACSR/AW								12
1-5000 KCMIL CU								13
2-900 ACSS/AW								14
2-1033.5 ACSR/AW								15
1-1033.5 ACSR/AW								16
2-1113 ACSS/AW								17
2-900 ACSS/AW								18
2-900 ACSS/AW								19
								20
2-1033.5 ACSR								21
2-1109 ACAR								22
2-1109 ACAR								23
2-1109 ACAR								24
2-636 ACSR								25
1750 MCM AL								26
1033.5 ACSR								27
2-636 ACSR								28
1750 MCM AL								29
2-1109 ACAR								30
2-1033.5 ACSR								31
2-1109 ACAR								32
2-1109 ACAR								33
2-1109 ACAR								34
2-1109 ACAR								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)
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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)	
2-2500 KCMIL CU								1
400 MCM CU								2
636 ACSR/AW								3
336.4 ACSR/AW								4
636 ACSR/AW								5
636 ACSR								6
2-1033.5 ACSR								7
2-1033.5 ACSR								8
250 MCM CU								9
336.4 ACSR								10
1-1033.5 ACSR								11
2-636 ACSR								12
2500 KCMIL CU								13
2-400 MCM CU								14
1-1033.5 ACSR								15
2-1033.5 ACSR								16
2-636 ACSR								17
2500 KCMIL CU								18
1033.5 ACSR								19
636 ACSR								20
1-1033.5 ACSR								21
605 ACSS								22
2-336.4 ACSR								23
1-750 MCM CU								24
636 ACSR								25
1750 KCMIL								26
900 ACSS/AW								27
636 ACSS								28
1-336.4 ACSR								29
2-336.4 ACSR								30
4-336.4 ACSR								31
900 ACSS/AW								32
2-636 ACSR								33
2-900 ACSS								34
2-636 ACSS								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)
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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)	
2-636 ACSS								1
636 ACSR								2
1033.5 ACSR								3
636 ACSR								4
250 MCM CU								5
250 MCM CU								6
1033.5 ACSR								7
1-1750 KCMIL AL								8
1-900 ACSS/AW								9
1-900 ACSS/AW								10
1-900 ACSS/AW								11
2-636 ACSR								12
1033.5 ACSR								13
1750 AL UG								14
1033.5 ACSR								15
1033.5 ACSR								16
1033.5 ACSR								17
1750 MCM CU								18
								19
394.5 5005								20
636 ACSR								21
336.4 ACSR								22
1033.5 ACSR/AW								23
336.4 ACSR/AW								24
1750 KCMIL AL								25
1033.5 ACSR/AW								26
336.4 ACSR/AW								27
1750 KCMIL AL								28
1033.5 ACSR/AW								29
900 ACSS/AW								30
1003.5 ACSR/AW								31
636 ACSR/AW								32
336.4 ACSR/AW								33
1750 KCMIL AL								34
1033.5 ACSR								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 10/26/2018	Year/Period of Report End of 2017/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)	
2-636 ACSR								1
2500 MCM CU								2
2-1109 ACAR								3
900 ACSS								4
2-900 ACSS								5
2-2500 KCMIL CU								6
2-3000 KCMIL CU								7
2-5000 KCMIL CU								8
1033.5 ACSR								9
1033.5 ACSR								10
336.4 ACSR								11
1033.5 ACSR								12
2-1033.5 ACSR								13
2-1109 ACAR								14
1-636 ACSR/AW								15
1109 ACAR								16
336.4 ACSR								17
250 MCM CU								18
900 ACSS/AW								19
250 MCM CU								20
2-1109 ACAR								21
1033.5 ACSR								22
636 ACSS								23
1033.5 ACSR								24
636 ACSR/AW								25
2-400 MCM CU								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	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)	
	197,120,204	3,124,585,640	3,321,705,844					1
				8,775,557	17,514,404	2,436,591	28,726,552	2
				5,648,775			5,648,775	3
								4
								5
								6
								7
								8
								9
								10
								11
								12
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								17
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								19
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								21
								22
								23
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								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	197,120,204	3,124,585,640	3,321,705,844	14,424,332	17,514,404	2,436,591	34,375,327	36

Schedule Page: 422.6 Line No.: 4 Column: f

San Diego Gas & Electric owns 85.64% and Imperial Irrigation District owns 14.36%

Schedule Page: 422.6 Line No.: 5 Column: f

San Diego Gas & Electric owns 85.64% and Imperial Irrigation District owns 14.36%

Schedule Page: 422.6 Line No.: 6 Column: f

Line has two sections: Palo Verde to North Gila, and North Gila to Colorado River. SDGE owns 76.22% and 85.64%, respectively, while Arizona Public Service owns 23.78% and 14.36% respectively.

Schedule Page: 422.6 Line No.: 7 Column: f

Line has two sections: Palo Verde to North Gila, and North Gila to Colorado River. SDGE owns 76.22% and 85.64%, respectively, while Arizona Public Service owns 23.78% and 14.36% respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	Imperial Valley	La Rosita	0.23	1S, 3	6.00	2	2
4							
5	Imperial Valley	Phase Shifting Transformer	0.17	1S	6.00	2	2
6							
7	East County	Jacumba Solar Gen 2	0.06	1S	9.00	1	1
8							
9	Loveland	Barrett	6.11	1S	9.00	2	2
10							
11	Torrey Pines	UC Metering	-0.15	1S	9.00	1	1
12							
13	UNDERGROUND						
14							
15	Torrey Pines	UC Metering	0.15	4		1	1
16							
17	Salt Creek	Border	0.12	4		1	1
18							
19	Salt Creek	Miguel	0.12	4		1	1
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		6.81		39.00	11	11

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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
900	ACSS/AW	16	230		890,002	504,294		1,394,296	3
									4
900	ACSS/AW	16	230		671,405	380,432		1,051,837	5
									6
636	ACSR/AW	9	138	30,652	53,067	108,384		192,103	7
									8
636	ACSS/AW	9	69	2,304,834	17,187,953	7,835,256		27,328,043	9
									10
1033.5	ACSR/AW	6	69				86,465	86,465	11
									12
									13
									14
1750	KCMILAL	8"	69			2,890,690		2,890,690	15
									16
3000	KCMILCU	8"	69			500,336		500,336	17
									18
3000	KCMILCU	8"	69			500,336		500,336	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
				2,335,486	18,802,427	12,719,728	86,465	33,944,106	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	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) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.
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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	SALT CREEK, Chula Vista	Dist. Unattended	69.00	12.00	
30	SAMPSON, San Diego	Dist. Unattended	69.00	12.00	
31	SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
32	SAN LUIS REY, Oceanside	Dist. Unattended	69.00	12.00	
33	SAN MARCOS, San Marcos	Dist. Unattended	69.00	12.00	
34	SAN MATEO, San Clemente	Dist. Unattended	138.00	12.00	
35	SAN YSIDRO, San Ysidro	Dist. Unattended	69.00	12.00	
36	SANTA YSABEL, Santa Ysabel	Dist. Unattended	69.00	12.00	
37	SANTEE, Santee	Dist. Unattended	138.00	12.00	
38	SCRIPPS, San Diego	Dist. Unattended	69.00	12.00	
39	SEWAGE PUMP STA (3), San Diego	Dist. Unattended	12.00	4.00	
40	SHADOWRIDGE, Vista	Dist. Unattended	138.00	12.00	

SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SHORECLIFFS, San Clemente	Dist. Unattended	12.00	4.00	
2	SOUTH SAN CLEMENTE, San Clemente	Dist. Unattended	12.00	4.00	
3	SPRING VALLEY, Spring Valley	Dist. Unattended	69.00	12.00	
4	STREAMVIEW, San Diego	Dist. Unattended	69.00	12.00	
5	STUART, Oceanside	Dist. Unattended	69.00	12.00	
6	SUNNYSIDE, San Diego	Dist. Unattended	69.00	12.00	
7	SWEETWATER, National City	Dist. Unattended	69.00	12.00	
8	TELEGRAPH CANYON, Chula Vista	Dist. Unattended	138.00	12.00	
9	TORREY PINES, San Diego	Dist. Unattended	69.00	12.00	
10	TRABUCO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
11	UCM Switchyard, San Diego	Dist. Unattended	69.00		
12	URBAN, San Diego	Dist. Unattended	69.00	12.00	
13	VALLEY CENTER, Valley Center	Dist. Unattended	69.00	12.00	
14	VISTA, Vista	Dist. Unattended	12.00	4.00	
15	WARNERS, Warner Springs	Dist. Unattended	69.00	12.00	
16	WARREN CANYON, Poway	Dist. Unattended	69.00	12.00	
17	WARREN CANYON, Poway	Dist. Unattended	69.00	4.00	
18	WITHERBY, San Diego	Dist. Unattended	12.00	4.00	
19	BAY BOULEVARD, Chula Vista	Trans. Unattended	230.00	69.00	
20	DOUBLETT Switchyard, San Diego	Trans. Unattended	138.00	69.00	
21	EAST COUNTY, Boulevard	Trans. Unattended	500.00	230.00	12.00
22	EAST COUNTY, Boulevard	Trans. Unattended	230.00	138.00	
23	ENCINA Switchyard, Carlsbad	Trans. Unattended	138.00		
24	ENCINA, Carlsbad	Trans. Unattended	230.00	138.00	
25	ESCONDIDO, Escondido	Trans. Unattended	230.00	69.00	
26	GOAL LINE, Escondido	Trans. Unattended	69.00		
27	IMPERIAL VALLEY, El Centro	Trans. Unattended	500.00	230.00	12.00
28	LOS COCHES, Lakeside	Trans. Unattended	138.00	69.00	
29	MIGUEL, Bonita	Trans. Unattended	230.00	69.00	
30	MIGUEL, Bonita	Trans. Unattended	230.00	138.00	
31	MIGUEL, Bonita	Trans. Unattended	500.00	230.00	12.00
32	MIRAMAR GT, San Diego	Trans. Unattended	12.00	69.00	
33	MISSION, San Diego	Trans. Unattended	138.00	69.00	
34	MISSION, San Diego	Trans. Unattended	230.00	69.00	
35	MISSION, San Diego	Trans. Unattended	230.00	138.00	
36	NARROWS, Borrego Springs	Trans. Unattended	88.00	69.00	12.00
37	OCOTILLO Switchyard, Ocotillo	Trans. Unattended	500.00		
38	OLD TOWN, San Diego	Trans. Unattended	230.00	69.00	
39	OTAY MESA Switchyard, Chula Vista	Trans. Unattended	230.00		
40	PENASQUITOS, San Diego	Trans. Unattended	138.00	69.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	PENASQUITOS, San Diego	Trans. Unattended	230.00	138.00	
2	PENASQUITOS, San Diego	Trans. Unattended	230.00	69.00	
3	SAN LUIS REY, Oceanside	Trans. Unattended	230.00	69.00	
4	SILVERGATE, San Diego	Trans. Unattended	230.00	69.00	
5	SUNCREST, Japatul	Trans. Unattended	500.00	230.00	12.00
6	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	69.00	
7	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	138.00	
8	TALEGA, San Clemente	Trans. Unattended	138.00	69.00	
9	TALEGA, San Clemente	Trans. Unattended	230.00	138.00	
10	WABASH Switchyard, San Diego	Trans. Unattended	69.00		
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Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 10/26/2018	Year/Period of Report End of 2017/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)	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)	
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) (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.
6	1					1
56	2					2
4	1					3
112	4					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	4				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)	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)	
						1
56	2					2
3	1					3
56	2					4
84	3	1				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
13	1					15
84	2	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
						28
56	2					29
112	4					30
3	1					31
112	4					32
112	4					33
45	2					34
56	2					35
12	1					36
56	2					37
84	3					38
46	6					39
84	3					40

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
3	1					2
56	2					3
56	2					4
8	1					5
28	1					6
56	2					7
112	4					8
112	4					9
112	4					10
						11
84	3					12
28	1					13
10	2					14
28	1					15
8	1					16
7	1					17
6	1					18
448	2					19
						20
1120	1					21
392	1					22
						23
784	2					24
672	3					25
						26
2840	9	2				27
448	2					28
448	2					29
784	2					30
2240	6	1	500/17kv	2	500	31
50	1					32
200	1					33
224	1					34
784	2					35
10	3					36
						37
448	2					38
						39
520	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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.
392	1	1				1
448	2					2
672	3		230/17kV	2	500	3
448	2	1				4
2240	6	1				5
672	3	1				6
392	1	1				7
140	1	1				8
1102	4		230/17kV	2	500	9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
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						31
						32
						33
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						40

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	7,482,245
3	Other Utility Plant	Sempra Energy	118	-190,550
4	Other Special Funds	Sempra Energy	128	-6,037,463
5	Other Accounts Receivable	Sempra Energy	143	-2,631,919
6	Accounts Receivable from Associated Companies	Sempra Energy	146	-32,882
7	Stores Expense Undistributed	Sempra Energy	163	-44,106
8	Prepayments	Sempra Energy	165	87,078,953
9	Unamortized Debt Expense	Sempra Energy	181	347,319
10	Unamortized Debt Expense	Sempra Energy	182	-924
11	Clearing Accounts	Sempra Energy	184	6,575,660
12	Research, Development & Demonstration Expenditure	Sempra Energy	188	495
13	Accumulated Provision for Injuries and Damages	Sempra Energy	228.3	-247
14	Accumulated Miscellaneous Operating Provisions	Sempra Energy	228.4	285,242
15	Accounts Payable	Sempra Energy	232	-9,575,159
16	Miscellaneous Current and Accrued Liabilities	Sempra Energy	242	-96,405
17	Miscellaneous Current and Accrued Liabilities	Sempra Energy	253	-311,194
18	Expend for Certain Civic and Political Activities	Sempra Energy	426.4	488,908
19	Other Electric Revenues	Sempra Energy	456	452
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Sempra Energy	146	467,517
22	Depreciation Expense	Sempra Energy	146	426,135
23	Environmental Services	Sempra Energy	146	16,116
24	External Affairs	Sempra Energy	146	279,844
25	Fleet Services	Sempra Energy	146	40,006
26	Human Resources	Sempra Energy	146	4,548,670
27	Information Technology	Sempra Energy	146	3,522,758
28	Real Estate & Facilities	Sempra Energy	146	4,353,033
29	Supply Management	Sempra Energy	146	1,088,770
30	Accouning & Finance	Sempra International Mexico	146	98
31	Depreciation Expense	Sempra International Mexico	146	2,126
32	Engineering / Construction Services	Sempra International Mexico	146	148,218
33	Environmental Services	Sempra International Mexico	146	174
34	Real Estate & Facilities	Sempra International Mexico	146	86,878
35	Supply Managment	Sempra International Mexico	146	42,848
36	Accounting & Finance	Sempra International South America	146	-718
37	Depreciation Expense	Sempra International South America	146	2,034
38	Environmental Services	Sempra International South America	146	174
39	Human Resources	Sempra International South America	146	277,158
40	Real Estate & Facilities	Sempra International South America	146	47,091
41	Supply Managment	Sempra International South America	146	17,323
42	Accounting & Finance	U.S Gas & Power Natural Gas	146	2,410
1	**Non-power Goods or Services Provided by Affiliated**			
2	Operation Supervision and Engineering	Sempra Energy	500	1,252

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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)
3	Miscellaneous Steam Power Expenses	Sempra Energy	506	100
4	Maintenance of Miscellaneous Steam Plant	Sempra Energy	514	163
5	Operation Supervision and Engineering	Sempra Energy	546	1,471
6	Miscellaneous Other Power Generation Expenses	Sempra Energy	549	766
7	Maintenance of Other Power Generation Expenses	Sempra Energy	554	1,304
8	System Control and Load Dispatching	Sempra Energy	556	283
9	Other Expenses	Sempra Energy	557	2,252
10	Transmission Operation Supv & Engineering	Sempra Energy	560	8,629
11	Load Dispatch	Sempra Energy	561	1,221
12	Station Expenses	Sempra Energy	562	1,215
13	Overhead Line Expense	Sempra Energy	563	7
14	Miscellaneous Transmission Expenses	Sempra Energy	566	254,981
15	Maintenance of Structures	Sempra Energy	569	10,167
16	Maintenance of Station Equipment	Sempra Energy	570	930
17	Operation Supervision and Engineering	Sempra Energy	571	1,511
18	Operation Supervision and Engineering	Sempra Energy	580	52,809
19	Load Dispatching	Sempra Energy	581	4,106
20	**Non-power Goods or Services Provided for Affiliate**			
21	Depreciation Expense	U.S Gas & Power Natural Gas	146	116,345
22	Environmental Services	U.S Gas & Power Natural Gas	146	381
23	External Affairs	U.S Gas & Power Natural Gas	146	15,054
24	Human Resources	U.S Gas & Power Natural Gas	146	188,790
25	Information Technology	U.S Gas & Power Natural Gas	146	306,391
26	Real Estate & Facilities	U.S Gas & Power Natural Gas	146	99,697
27	Supply Management	U.S Gas & Power Natural Gas	146	219,805
28	Accounting & Finance	U.S Gas & Power Renewables	146	195
29	Depreciation Expense	U.S Gas & Power Renewables	146	21,631
30	Engineering / Const. Services	U.S Gas & Power Renewables	146	100,819
31	Environmental Services	U.S Gas & Power Renewables	146	261
32	Human Resources	U.S Gas & Power Renewables	146	85,934
33	Real Estate & Facilities	U.S Gas & Power Renewables	146	76,725
34	Supply Management	U.S Gas & Power Renewables	146	17,186
35	Accounting & Finance	Southern California Gas Company	146	34,286,626
36	Customer Services	Southern California Gas Company	146	686,146
37	Depreciation Expense	Southern California Gas Company	146	6,117,162
38	Engineering and Construction Services	Southern California Gas Company	146	1,564,795
39	Environmental Services	Southern California Gas Company	146	886,847
40	External Affairs	Southern California Gas Company	146	1,040,012
41	Fleet Services	Southern California Gas Company	146	629,840
42	Human Resources	Southern California Gas Company	146	4,287,859
1	**Non-power Goods or Services Provided by Affiliated**			
2	Meter Expenses	Sempra Energy	586	9,696
3	Customer Installations Expenses	Sempra Energy	587	123
4	Miscellaneous Distribution Expenses	Sempra Energy	588	968,407

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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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	Rents, Electric Distribution	Sempra Energy	589	30
6	Maintenance Supervision and Engineering	Sempra Energy	590	1,282
7	Maintenance of Station Equipment	Sempra Energy	592	538
8	Maintenance of Overhead Lines	Sempra Energy	593	6,406
9	Maintenance of Meters	Sempra Energy	597	417
10	Maintenance Distribution Expenses	Sempra Energy	598	47
11	Operation Supervision and Engineering	Sempra Energy	850	1,469
12	Compressor Station Labor and Expenses	Sempra Energy	853	542
13	Mains Expenses	Sempra Energy	856	258
14	Maintenance of Mains	Sempra Energy	863	1,321
15	Maintenance of Measuring and Regulating Station Eq	Sempra Energy	865	283
16	Gas Trans Maint Operation Sup and Engineering	Sempra Energy	870	13,460
17	Mains and Service Expenses	Sempra Energy	874	6,177
18	Measuring and Regulating Station Expenses-General	Sempra Energy	875	257
19	Customer Installations Expenses	Sempra Energy	879	24,125
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information Technology	Southern California Gas Company	146	74,043,807
22	Real Estate & Facilities	Southern California Gas Company	146	2,184,942
23	Supply Management	Southern California Gas Company	146	2,077,216
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42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Distribution Other Expenses	Sempra Energy	880	16,679
3	Maintenance Supervision and Engineering	Sempra Energy	885	2
4	Maintenance of Mains	Sempra Energy	887	3,681
5	Meter Reading Expenses	Sempra Energy	902	2,086
6	Customer Records and Collection Expenses	Sempra Energy	903	15,202

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TRANSACTIONS WITH 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)
7	Customer Assistance Expenses	Sempra Energy	908	27,721
8	Miscellaneous Customer Service and Info Exp	Sempra Energy	910	255,413
9	Administrative and General Salaries	Sempra Energy	920	-2,156,740
10	Office Supplies and Expenses	Sempra Energy	921	224,540
11	Outside Services Employed	Sempra Energy	923	54,298,555
12	Property Insurance	Sempra Energy	924	306,840
13	Injuries and Damages	Sempra Energy	925	23,927,077
14	Employee Pension and Benefits	Sempra Energy	926	40,149,107
15	Regulatory Commission Expenses	Sempra Energy	928	741,583
16	Miscellaneous General Expenses	Sempra Energy	930.2	784
17	Maintenance of General Plant	Sempra Energy	935	10,302
18	Purchased Power	Energia Sierra Juarez	555	47,470,892
19	Construction Work in Porgress	Southern California Gas Company	107	11,719,340
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Other Utility Plant	Southern California Gas Company	118	7,921,231
3	Clearing Accounts	Southern California Gas Company	184	2,692,437
4	Miscellaneous Deferred Debits	Southern California Gas Company	186	62,118
5	Accounts Payable	Southern California Gas Company	232	2,172
6	Expend for Civic and Political Activities	Southern California Gas Company	426.4	369
7	Miscellaneous Transmission Expenses	Southern California Gas Company	566	701
8	Miscellaneous Distribution Expenses	Southern California Gas Company	588	21,195

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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)
9	Operation Supervision and Engineering	Southern California Gas Company	850	2,405,650
10	System Control and Load Dispatching	Southern California Gas Company	851	737,297
11	Compressor Station Labor and Expenses	Southern California Gas Company	853	6,182
12	Other Expenses	Southern California Gas Company	859	7,091
13	Maintenance Supervision and Engineering	Southern California Gas Company	861	1,298
14	Maintenance of Mains	Southern California Gas Company	863	547,953
15	Maintenance of Compressor Station Equipment	Southern California Gas Company	864	-3,859
16	Operation Supervision and Engineering	Southern California Gas Company	870	3,602,607
17	Mains and Services Expenses	Southern California Gas Company	874	40,632
18	Distribution Other Expenses	Southern California Gas Company	880	143,144
19	Maintenance of Mains	Southern California Gas Company	887	55,548
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Maintenance of Meters and House Regulators	Southern California Gas Company	893	60,069
3	Meter Reading Expenses	Southern California Gas Company	902	97,451
4	Customer Records and Collection Expenses	Southern California Gas Company	903	2,223,469
5	Supervision, Customer Services	Southern California Gas Company	907	656
6	Customer Assistance Expenses	Southern California Gas Company	908	924,731
7	Miscellaneous Customer Service and Info Exp	Southern California Gas Company	910	236,882
8	Outside Services Employed	Southern California Gas Company	923	56,963,867
9	Injuries and Damages	Southern California Gas Company	925	415,740
10	Employee Pensions and Benefits	Southern California Gas Company	926	78,507

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [ ] An Original (2) [X] A Resubmission	10/26/2018	End of 2017/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	Regulatory Commission Expenses	Southern California Gas Company	928	1,741,822
12	Miscellaneous General Expense	Southern California Gas Company	930.2	165,004
13	Rents	Southern California Gas Company	931	1,023,208
14	Maintenance of General Plant	Southern California Gas Company	935	693,996
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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

1 (Rows 1-104)
All non-power goods and services provided by affiliated companies are billed to San Diego Gas and Electric at fully loaded cost.

2 (Rows 2-71)
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; 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 - Legal, this method is weighted average of annual labor budget for departments that report to the Executive Vice President & General Counsel; Average - CFO, this method is a weighted average of annual labor budget for departments that report to the CFO; 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; Average - VP of Audit Services, this method is a weighted average of annual labor budget for departments that report to the VP of Audit Services; 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 - 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 - Fire Insurance, this method allocates all costs for Fire Insurance based on miles of electrical lines 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 workload 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 FTE's are reallocated by multifactor; 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 - Major Projects & Controls, the Major Projects and Controls group allocates its overall costs based on a percentage of direct labor charges to each business segment for each month; and overall average is estimated for the Plan year. Causal - MyInfo Services Contract, MyInfo services cost is allocated by the number of people in the MyInfo system. The portion of services attributable to 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 summary value of Sempra's major pension savings funds and San Diego Gas & Electric's Nuclear Decommissioning Trust (NDT). The Sempra Energy Corporate Center and Sempra Global value is then re-allocated by the US-based FTE's, with Sempra Energy Corporate Center FTE's further re-allocated based on Multi-factor (basic); 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; Causal - Audit Plan, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; 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; Causal - Audit US, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; Causal - SOX, this allocation is a weighted average of the workload of each employee within SOX Compliance based on an annual time study. Parent workload hours are reallocated using Multi-Factor Basic, resulting in a blended percentage; Causal - Law Department, this allocation method is based on direct time charged by attorneys, paralegal and law clerks in the Archer timekeeping system during the previous Jan-Sep period. Hours for Corporate are re-allocated by Multi-Factor Basic, resulting in a blended percentage; Causal - Primary Property - Insurance, this method uses the most recent risk-adjusted primary property premiums per business unit as the basis to allocate the cost of future premiums. The amount for Corporate Center is then re-allocated by Multi-Factor Basic to result in a blended percentage; Causal - Excess Property, this method uses the most recent risk-adjusted OIL property premiums per business unit as the basis to allocate the cost of future property insurance. The premium for Corporate Center is then re-allocated by Multi-Factor Basic to result in a blended percentage; Causal - Vehicle Insurance, Utility fleet vehicles are covered under self-insurance and umbrella policies; this policy is for Corporate Vehicles. The most recent risk-adjusted premiums are the basis to allocate the cost of future vehicle Insurance. The premiums for Corporate Center is then re-allocated by Multi-Factor Basic to result in a blended percentage; Causal - Excess Worker's Compensation, this method uses recent premiums as the basis to allocate the cost of Workers Compensation insurance for California-based employees. The Corporate Center amount is then allocated by Multi-Factor Basic to result in a blended percentage; and, Causal - Global Worker's Compensation, this method uses recent premiums as the basis to allocate the cost of Workers Compensation insurance for California-based employees. The Corporate Center amount is then allocated by Multi-Factor Basic to result in a blended percentage;

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, and follow as such: 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. Amenity floors in the HQ are excluded, as they benefit all occupants ratably. 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 - HQ Depreciation - depreciation expense & ROR related to "HQ leasehold improvements" is allocated based on the square footage directly occupied by the business units Corporate Center's direct occupation except for the portion which is retained, is re-allocated based on the Multi-Factor base allocation; 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.

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2 (Rows 2-71)
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; 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 - Legal, this method is weighted average of annual labor budget for departments that report to the Executive Vice President & General Counsel; Average - CFO, this method is a weighted average of annual labor budget for departments that report to the CFO; 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; Average - VP of Audit Services, this method is a weighted average of annual labor budget for departments that report to the VP of Audit Services; 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 managin are Retained; 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 - Fire Insurance, this method allocates all costs for Fire Insurance based on miles of electrical lines 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 workload 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 FTE’s are reallocated by multifactor; 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 - Major Projects & Controls, the Major Projects and Controls group allocates its overall costs based on a percentage of direct labor charges to each business segment for each month; and overall average is estimated for the Plan year. Causal - MyInfo Services Contract, MyInfo services cost is allocated by the number of people in the MyInfo system. The portion of services attributable to 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 summary value of Sempra’s major pension savings funds and San Diego Gas & Electric’s Nuclear Decommissioning Trust (NDT). The Sempra Energy Corporate Center and Sempra Global value is then re-allocated by the US-based FTE’s, with Sempra Energy Corporate Center FTE’s further re-allocated based on Multi-factor (basic); 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; Causal - Audit Plan, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; 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; Causal - Audit US, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit; Causal - SOX, this allocation is a weighted average of the workload of each employee within SOX Compliance based on an annual time study. Parent workload hours are reallocated using Multi-Factor Basic, resulting in a blended percentage; Causal - Law Department, this allocation method is based on direct time charged by attorneys, paralegal and law clerks in the Archer timekeeping system during the previous Jan-Sep period. Hours for Corporate are re-allocated by Multi-Factor Basic, resulting in a blended percentage; Causal - Primary Property - Insurance, this method uses the most recent risk-adjusted primary property premiums per business unit as the basis to allocate the cost of future premiums. The amount for Corporate Center is then re-allocated by Multi-Factor Basic to result in a blended percentage; Causal - Excess Property, this method uses the most recent risk-adjusted OIL property premiums per business unit as the basis to allocate the cost of future property insurance. The premium for Corporate Center is then re-allocated by Multi-Factor Basic to result in a blended percentage; Causal - Vehicle Insurance, Utility fleet vehicles are covered under self-insurance and umbrella policies; this policy is for Corporate Vehicles. The most recent risk-adjusted premiums are the basis to allocate the cost of future vehicle Insurance. The premiums for Corporate Center is then re-allocated by Multi-Factor Basic to result in a blended percentage; Causal - Excess Worker's Compensation, this method uses recent premiums as the basis to allocate the cost of Workers Compensation insurance for California-based employees. The Corporate Center amount is then allocated by Multi-Factor Basic to result in a blended percentage; and, Causal - Global Worker's Compensation, this method uses recent premiums as the basis to allocate the cost of Workers Compensation insurance for California-based employees. The Corporate Center amount is then allocated by Multi-Factor Basic to result in a blended percentage; 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, and follow as such: 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. Amenity floors in the HQ are excluded, as they benefit all occupants ratably. 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 - HQ Depreciation - depreciation expense & ROR related to "HQ leasehold improvements" is allocated based on the square footage directly occupied by the business units Corporate Center's direct occupation except for the portion which is retained, is re-allocated based on the Multi-Factor base allocation; 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.

[3] (Rows 73-104)
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 133 Southern California Gas Company cost centers. The following causal beneficial relationship information is a summary of the 25 varying methodologies used: 21 cost centers used a form of miles of pipe installed and/or current year by service territory allocations; 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; 17 cost centers used a form of LAN ID counts to determine the shared allocation; 17 cost centers used a form of departmental studies based on current year budgeted activities and/or dollars; 11 cost centers used a form of gas meter counts and service territory allocations; 7 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; 6 cost centers used a form of employee count statistics for support; 5 cost centers used a form of allocation based on the ratio of gas sent to San Diego Gas and Electric compared to total gas throughput; 4 cost centers used a form of 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; 4 cost centers used a form of budgeted current year project assignments; 4 cost centers used a form of a count of hardware servers; 3 cost centers used a form of an allocation of space study identifying building square footage assigned; 2 cost centers used a form of an allocation based on the weighted average of total utility gas revenue; 2 cost centers used a form of allocation of voice count statistics; 2 cost centers used a form of a ratio of horsepower in compressor engines in the service territory; there was one use by a cost center of each of the remaining allocation methodologies: an internal departmental multi-factor using contract volume activity; an allocation using number of stakeholders at each utility; the

summary of legal cases handled in previous year and current year; a forecast of total connected gas meters within specific budgeted activity; a forecast of total miles of pipe within specific budgeted activity; the number of capital projects assigned weighed by individual asset allocation; a ratio determined by historical claims and payments processed; an allocation based on vehicle MRU along with the manager's estimate of employee time; a study related to the CPU utilization of company computer assets; and, an allocation of server system data interface statistics.

[4] (Row 105-152)
All non-power goods and services provided by San Diego Gas and Electric are billed at fully loaded cost.

[5] (Row 105)
Affiliate companies charged by San Diego Gas and Electric for less than $250,000 include: Sempra LNG.

[6] (Rows 106-152)
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 123 San Diego Gas and Electric cost centers. The following causal-beneficial relationship information is a summary of the 21 varying methodologies used: 29 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 26 cost centers used a form of LAN ID counts to determine the shared allocation; 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; 7 cost centers used a form of budgeted current year project assignments; 5 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; 4 cost centers used a form of an allocation of time by Vice President or 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; 4 cost centers used a form of Full Time Employee equivalent statistics for support; 4 cost centers used a form of allocation using an employee matrix to determine support; 4 cost centers used a form of a count of network sites; 4 cost centers used a form of a count of hardware servers; 3 cost centers used a form of allocation of application software login activity and statistics for active accounts; 3 cost centers used a form of allocation of voice count statistics; 2 cost centers used a form of allocation of computer and/or server system and resource usage statistics; 2 cost centers used a form of the number of contracts supported; there was one use by a cost center of each of the remaining allocation methodologies: electric and gas meter counts and service territory allocations; the weighted average of Office Services budget; the weighted average allocation of Sempra Energy Utility (including both Southern California Gas Company and San Diego Gas and Electric) gas revenue; the ratio of miles of pipe installed existing and/or current year by service territory allocations; projections of the project manager based on anticipated project assignments; and, a study related to the CPU utilization of company computer assets.

Schedule | Page No.