THIS FILING IS		
Item 1: [X] 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** 2018/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 2018/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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(858) 503-5130	(1) ☒ An Original (2) ☐ A Resubmission	04/16/2019

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Bruce A. Folkmann	Bruce A. Folkmann	04/16/2019
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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	N/A
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

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".

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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

GENERAL INFORMATION

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

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

8330 Century Park Court, San Diego, California 92123

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

California, April 6, 1905

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

Not Applicable

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

Electric and Natural Gas Services
State of California

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

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

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or 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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Chief Executive Officer	Kevin C. Sagara	500,000
2	President	Scott D. Drury	464,400
3	Chief Operating Officer	Caroline A. Winn	420,000
4	Chief Regulatory Officer	Lee Schavrien	376,900
5	Chief Information Officer	J. Chris Baker	376,200
6	Vice President, Chief Financial Officer,	Bruce A. Folkmann	330,300
7	Chief Accounting Officer, Treasurer, Controller		
8	Chief Human Resources & Chief Administrative Officer	Randall L. Clark	309,600
9	Corporate Secretary	Kari McCulloch	239,227
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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 & Non-Executive Chairman (1) (2)	San Diego, CA
2	Scott D. Drury, Director and President	San Diego, CA
3	Jeffrey W. Martin, Director (1) (3)	San Diego, CA
4	Trevor I. Mihalik, Director (1)	San Diego, CA
5	G. Joyce Rowland, Director (1)	San Diego, CA
6	Kevin C. Sagara, Director & Chief Executive Officer	San Diego, CA
7	Caroline A. Winn, Director & Chief Operating Officer	San Diego, CA
8	Martha B. Wyrsch, Director (1)	San Diego, CA
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11	(1) Does not hold any offices with SDG&E but are officers	
12	of SDG&E's ultimate parent, Sempra Energy.	
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14	(2) Retired 02/28/18	
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16	(3) Resigned 04/30/18	
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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	ER18-358-000
3		
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5	FERC Electric Tariff, Volume No.11	ER18-1690-000
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8	FERC Electric Tariff, Volume No.11	ER18-488-000
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11	FERC Electric Tariff, Volume No.11	ER18-211-000
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14	FERC Electric Tariff, Volume No.11	ER18-416-000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)?

[ ] Yes
[X] 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	20171130-5155	11/30/2017	ER18-358-000	TO4 Cycle 5 Formula Rate Annual	FERC Electric Tariff, Volume No.11
3				Informational Filing	
4					
5	20180525-5154	05/25/2018	ER18-1690-000	Cycle 7 Appendix X Annual	FERC Electric Tariff, Volume No.11
6				Informational Filing	
7					
8	20171220-5211	12/20/2017	ER18-488-000	2018 Reliability Service Balancing	FERC Electric Tariff, Volume No.11
9				Account ("RSBA") Filing	
10					
11	20171101-5161	11/01/2017	ER18-211-000	2018 Transmission Revenue Balancing	FERC Electric Tariff, Volume No.11
12				Account Adjustment ("TRBAA") Filing	
13					
14	20171208-5117	12/08/2017	ER18-416-000	2018 Transmission Access Charge	FERC Electric Tariff, Volume No.11
15				Balancing Account Adjustment	
16				("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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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. San Francisco occupied suite 2050 and 2060 on a month to month basis ($10,760.99 per month) until January 7, 2019.

   Mission Market Payment Office, renewed lease on October 10, 2018, extended term commencing on 05/01/2019 and expiring on 04/30/2024, monthly rent for renewal term is TBD.

   Washington DC lease, extended term on 12/26/2018 until 10/31/2025, at an annual rate of $48.00 per square foot with 2.5% annual increase. An additional term extension is also available to extend until 10/31/2030.

5. SDG&E placed in service a new Transmission Line TL6958 (Cameron Substation to Crestwood Substation) on May 29, 2018. This consisted of constructing approximately 7.5 miles of overhead double circuit 69kV transmission line and energizing one side of that structure as TL6958.

   SDG&E placed into service a new 14.67 mile 230kV Transmission Line TL23071 (Sycamore Canyon Substation to Penasquitos Substation) on August 29, 2018. This consisted of constructing 11.85 miles of underground 230kV circuit and installing 2.2 miles of overhead conductor on one side of an existing double circuit overhead transmission line.

6. During 2018, San Diego Gas & Electric issued commercial paper with an average daily balance of $235.2 million and a maximum outstanding balance of $457.6 million. The year-end balance was $291.1 million.

   There were no issuances or retirements of long-term debt by San Digeo Gas & Electric in Q4 2018.

7. None

8. On September 1, 2018, 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 2018 is $4.6 million above 2017 base wages.

   Total annualized wages for represented employees including overtime in 2018 is $8.6 million above 2017 wages including overtime.

9. Please refer to the Legal Proceedings sections of the Notes to the Financial Statements on page 123.67.

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
John A. Sowers	Senior Vice President - Asset Management	Resigned,02/13/2018
Steven D. Davis	Director and Non-executive Chairman	Retired, 02/28/2018
Lee Schavrien	Chief Regulatory Officer	Retired, 03/31/2018
Jimmie I. Cho	Senior Vice President - Gas Engineering and Distribution Operations changed to Senior Vice President - Gas Distribution Operations	Changed, 04/07/2018
Rodger R. Schwecke	Senior Vice President - Gas Transmission and System Operations changed to Senior Vice President - Gas Transmission and Engineering	Changed, 04/07/2018
J. Christopher Baker	Chief Information Officer	Retired, 04/30/2018
P. Kevin Chase	Senior Vice President - Chief Information Officer and Chief Digital Officer	Elected, 06/20/2018
Benjamin W.F. Gordon	Vice President - Technology Operations & Infrastructure Management	Appointed,08/20/2018
Emily C. Shults	Vice President - Energy Supply	Resigned, 08/24/2018
Michael M. Schneider	Vice President, Operations Support and Sustainability, and Chief Environmental Officer changed to Vice President - Clean Transportation and Asset Management	Changed, 08/25/2018
Estela M. de Llanos	Vice President - Operations Support Sustainability and Chief Environmental Officer	Appointed,08/25/2018
Kendall K. Helm	Vice President - Energy Supply	Appointed, 08/25/2018
James M. Spira	Assistant Secretary	Appointed, 08/25/2018
Scott D. Drury	Principal Executive Officer	Undesignated, 09/07/2018
Kevin C. Sagara	Director, Chairman and Chief Executive Officer; Principal Executive Officer	Appointed, 09/08/2018 Designated, 09/08/2018

Changes in Directors:

Name	Title	Effective Date
Jeffrey W. Martin	Director	Resigned, 04/30/2018

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

14. N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	20,491,384,467	18,390,733,610
3	Construction Work in Progress (107)	200-201	1,219,293,740	1,450,531,198
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		21,710,678,207	19,841,264,808
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,787,171,251	6,284,565,920
6	Net Utility Plant (Enter Total of line 4 less 5)		14,923,506,956	13,556,698,888
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)		14,923,506,956	13,556,698,888
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,030,598	5,790,994
19	(Less) Accum. Prov. for Depr. and Amort. (122)		326,050	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	155,016,001	82,663,273
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)		973,933,996	1,033,106,611
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		232,394,419	102,971,280
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,367,048,964	1,224,167,858
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,252,036	8,098,377
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)		302,508,480	297,487,258
41	Other Accounts Receivable (143)		106,130,463	77,944,781
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,015,424	4,178,412
43	Notes Receivable from Associated Companies (145)		-12	0
44	Accounts Receivable from Assoc. Companies (146)		217,142	426,650
45	Fuel Stock (151)	227	0	3,447,152
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	136,203,688	136,123,860
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	170,495,651	198,803,755

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		155,016,001	82,663,273
54	Stores Expense Undistributed (163)	227	0	1,070,047
55	Gas Stored Underground - Current (164.1)		361,245	299,024
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		6,219	7,563
57	Prepayments (165)		76,241,970	60,107,301
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		2,433,968	2,427,536
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		70,728,000	69,780,000
62	Miscellaneous Current and Accrued Assets (174)		3,700,000	2,294,000
63	Derivative Instrument Assets (175)		314,735,501	145,375,780
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		232,394,419	102,971,280
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)		798,589,007	813,880,619
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		34,501,516	33,399,333
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	1,366,481	1,366,481
72	Other Regulatory Assets (182.3)	232	1,810,362,978	1,814,742,422
73	Prelim. Survey and Investigation Charges (Electric) (183)		813,362	355,845
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)		-1,231,487	-1,743,983
77	Temporary Facilities (185)		629,731	87,692
78	Miscellaneous Deferred Debits (186)	233	108,837,345	150,127,818
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)		6,483,720	8,933,154
82	Accumulated Deferred Income Taxes (190)	234	147,260,603	193,614,853
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,109,024,249	2,200,883,615
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		19,198,169,176	17,795,630,980

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

The 13-month Average Electric Prepayments for 2018 is $50,549,308.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	end of 2018/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	479,665,368	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	4,683,700,304	4,266,831,380
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)	-9,578,079	-8,217,268
16	Total Proprietary Capital (lines 2 through 15)		6,011,923,326	5,596,415,214
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,776,266,000	4,573,220,000
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)		12,609,585	11,674,567
24	Total Long-Term Debt (lines 18 through 23)		4,763,656,415	4,561,545,433
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,254,952,617	1,032,560,214
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		25,902,087	22,886,561
29	Accumulated Provision for Pensions and Benefits (228.3)		217,186,910	185,844,199
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		97,429,293	150,086,691
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		872,109,559	837,158,537
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,467,580,466	2,228,536,202
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		290,971,029	252,634,005
38	Accounts Payable (232)		478,117,692	533,763,816
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		60,547,337	40,399,413
41	Customer Deposits (235)		82,186,953	79,450,451
42	Taxes Accrued (236)	262-263	29,872,707	9,592,822
43	Interest Accrued (237)		42,378,076	41,258,087
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	end of 2018/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		5,310,800	4,921,676
48	Miscellaneous Current and Accrued Liabilities (242)		176,709,521	284,219,634
49	Obligations Under Capital Leases-Current (243)		329,962,233	53,696,924
50	Derivative Instrument Liabilities (244)		134,348,425	199,865,892
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		97,429,293	150,086,691
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)		1,532,975,480	1,349,716,029
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		51,804,881	62,987,727
57	Accumulated Deferred Investment Tax Credits (255)	266-267	15,623,118	17,640,050
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	321,262,586	294,302,384
60	Other Regulatory Liabilities (254)	278	2,301,355,349	1,993,036,666
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)		1,651,155,259	1,588,514,956
64	Accum. Deferred Income Taxes-Other (283)		80,832,296	102,936,319
65	Total Deferred Credits (lines 56 through 64)		4,422,033,489	4,059,418,102
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		19,198,169,176	17,795,630,980

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	5,132,471,203	4,631,183,368		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,176,303,937	3,033,572,828		
5	Maintenance Expenses (402)	320-323	157,916,904	143,578,144		
6	Depreciation Expense (403)	336-337	566,472,786	514,716,512		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	87,577,972	76,951,462		
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		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,334,790	1,510,600		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	146,482,506	133,981,724		
15	Income Taxes - Federal (409.1)	262-263	106,373,570	100,049,127		
16	- Other (409.1)	262-263	30,765,105	65,007,563		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	242,146,627	372,504,341		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	206,348,948	418,232,160		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,016,932	1,604,778		
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)		4,308,024,061	4,071,879,714		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		824,447,142	559,303,654		

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
4,564,474,007	4,088,935,308	570,095,663	547,004,881	-2,098,467	-4,756,821	2
						3
2,821,320,974	2,675,271,008	359,303,243	362,711,028	-4,320,280	-4,409,208	4
134,272,155	125,325,445	23,644,749	18,252,699			5
499,241,280	457,420,476	65,298,687	56,289,863	1,932,819	1,006,173	6
						7
71,592,556	64,357,703	15,985,416	12,593,759			8
15,744	15,744					9
	46,619,051					10
						11
1,326,640	719,044	1,008,150	791,556			12
						13
125,403,825	116,043,046	20,422,825	17,258,690	655,856	679,988	14
93,320,720	147,421,808	13,052,850	-47,372,681			15
27,732,020	62,007,746	3,033,085	2,999,817			16
222,542,113	306,770,489	19,604,514	65,733,852			17
180,963,984	416,737,107	25,384,964	1,495,053			18
-1,504,003	2,117,707	-512,929	-512,929			19
						20
						21
						22
						23
						24
3,814,300,040	3,587,352,160	495,455,626	487,250,601	-1,731,605	-2,723,047	25
750,173,967	501,583,148	74,640,037	59,754,280	-366,862	-2,033,774	26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)		824,447,142	559,303,654		
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		
34	(Less) Expenses of Nonutility Operations (417.1)		314			
35	Nonoperating Rental Income (418)		33,415	32,897		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		15,377,549	6,968,304		
38	Allowance for Other Funds Used During Construction (419.1)		59,969,625	63,269,244		
39	Miscellaneous Nonoperating Income (421)		763,823	355,197		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		76,144,098	70,660,848		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		250,048	250,048		
45	Donations (426.1)		7,362,363	5,758,393		
46	Life Insurance (426.2)		-6,000,301	-6,138,140		
47	Penalties (426.3)		10,000	113,152		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,420,843	1,461,950		
49	Other Deductions (426.5)		20,509,706	3,034,371		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		24,552,659	4,479,774		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	700,161	657,648		
53	Income Taxes-Federal (409.2)	262-263	-1,747,422	-295,350		
54	Income Taxes-Other (409.2)	262-263	-883,667	-169,532		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	8,412,437	12,484,363		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,426,173	5,509,344		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		3,055,336	7,167,785		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		48,536,103	59,013,289		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		200,012,289	185,808,926		
63	Amort. of Debt Disc. and Expense (428)		3,450,807	3,445,542		
64	Amortization of Loss on Reaquired Debt (428.1)		2,799,425	3,334,760		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		20,172,691	13,446,610		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		20,320,891	21,031,665		
70	Net Interest Charges (Total of lines 62 thru 69)		206,114,321	185,004,173		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		666,868,924	433,312,770		
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)		666,868,924	406,693,763		

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

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

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

Total Operating Revenues excludes amounts associated with interdepartmental transfers.

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

Eliminates interdepartmental transfers	$ (5,531,512)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	3,433,045
	$ (2,098,467)

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

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

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 Revenues excludes amounts associated with interdepartmental transfers.

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

Eliminates interdepartmental transfers	$ (5,531,512)
Citizens Energy Corporation Operating Expenses	1,211,233
	$ (4,320,280)

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

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

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	(904,141)
	$ 1,932,819

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

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

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

Citizens Energy Corporation Property Tax	$ 631,559
Citizens Energy Corporation Payroll Tax	24,297
	$ 655,856

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

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

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 $145.9 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $11.5 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.

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: 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 $145.9 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $11.5 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.

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.: 76 Column: d
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		4,266,831,380	4,310,137,617
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		666,868,924	406,693,763
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			-250,000,000	(450,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-250,000,000	(450,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		4,683,700,304	4,266,831,380
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		4,683,700,304	4,266,831,380
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	666,868,924	406,693,763
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	566,472,786	514,716,512
5	Impairment of Wildfire Asset		351,067,753
6	Amortization of Unrecovered Plant and Regulatory Study Costs	87,593,716	123,586,257
7			-549,655
8	Deferred Income Taxes (Net)	40,783,943	-11,808,100
9	Investment Tax Credit Adjustment (Net)	-2,016,932	1,604,778
10	Net (Increase) Decrease in Receivables	-33,108,384	-69,701,497
11	Net (Increase) Decrease in Inventory	4,376,494	-25,598,530
12	Net (Increase) Decrease in Allowances Inventory	-95,994,355	-14,715,000
13	Net Increase (Decrease) in Payables and Accrued Expenses	15,555,859	37,179,517
14	Net (Increase) Decrease in Other Regulatory Assets	-31,043,220	-724,150,341
15	Net Increase (Decrease) in Other Regulatory Liabilities	296,280,836	997,902,218
16	(Less) Allowance for Other Funds Used During Construction	59,969,625	63,269,244
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: Net (Increase) Decrease in Prepayments and Other	-17,661,648	135,712,144
19	Net Increase (Decrease) in Accrued Interest and Taxes	23,153,154	1,520,629
20			
21	Other - Net	104,479,498	-159,481,176
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,565,771,046	1,500,710,028
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,598,598,989	-1,618,087,731
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	-59,969,625	-63,269,244
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,538,629,364	-1,554,818,487
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	1,054	31,242,113
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 Inscurace - Net		5,859,427
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Decommissioning Trust Fund Purchase	-890,292,254	-1,313,621,571
54	Decommissioning Trust Fund Sales	890,292,254	1,313,621,571
55	Increase (Decrease) in Customer Advances for Construction	-14,143,395	1,802,797
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,552,771,705	-1,515,914,150
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	398,231,598	398,216,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Other: LTD Issuance Cost Amortization	-3,500,000	-3,500,000
66	Net Increase in Short-Term Debt (c)	38,337,023	252,634,005
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	433,068,621	647,350,005
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-196,914,303	-175,714,000
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	-250,000,000	-450,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-13,845,682	21,636,005
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-846,341	6,431,883
87			
88	Cash and Cash Equivalents at Beginning of Period	8,098,877	1,666,994
89			
90	Cash and Cash Equivalents at End of period	7,252,536	8,098,877

NOTES TO FINANCIAL STATEMENTS

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

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

NOTES TO FINANCIAL STATEMENTS

A. Notes for Statement of Cash Flows:

Supplemental Disclosure of Cash Flow Information:			12/31/2018
Income tax payments (refunds), net			111,652,449
Interest payments, net of amounts capitalized			190,309,512
Reconciliation of Cash and Cash Equivalents at December 31, 2018:			
Account 131	Cash		7,252,036
Account 135	Working Funds		500
Account 136	Temporary Cash Investments		-
		$	7,252,536

Supplemental Disclosure of Non-Cash Investing Activities:	
Increase (Decrease) in capital lease obligation for investments in property, plant and equipment	550,000,000
Accrued Capital Expenditures	(159,416,000)

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, 2018, as filed with the SEC on February 26, 2019. 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 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 U.S. GAAP. The principal differences of this basis of accounting from U.S. 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 VIEs for GAAP purposes
- Certain plant in service, accumulated depreciation, and regulatory assets

▪Certain pension costs between other income and A&G

Accordingly, certain Notes to the Financial Statements are not reflective of SDG&E's Financial Statements contained herein, which have been prepared on a stand alone basis, which exclude consolidation with OMEC LCC's 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 U.S GAAP reporting requirements as mentioned above, certain amounts disclosed in Notes 1-13 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.

OMEC LLC PPA

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, 2018, the capital lease was valued at $595 million, and the corresponding capital lease obligation with a 10-year term was valued at $313 million.

At December 31, 2018, the future minimum lease payments and present value of the net minimum lease payments under these capital leases were as follows:

(Dollars in millions)

2019 Total minimum lease payments(1)		331
Less: interest(2)		(18)
Present value of net minimum lease payments(3)	$	313

(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 $313 million in Current Portion of Capital Lease Obligation on the Balance Sheet at December 31, 2018.*

The annual amortization charge for the OMEC power purchase agreement was $41 million for 2018 and $38 million for 2017.

ASU 2017-07

SDG&E elected to adopt GAAP accounting for FERC reporting related to the adoption of ASU 2017-07. The adoption resulted in a negligible impact to rate base, an increase of $3.1 million to A&G expenses.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

BASIS OF PRESENTATION

This is a report of SDG&E. SDG&E's common stock is wholly owned by Enova, 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.

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, 2018 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 Note 4.

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.

"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 unadjusted 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 and 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; and
- 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.

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, 2018	2017	2016
Allowances for collection of receivables at January 1	$ 9	$ 8	$ 9
Provisions for uncollectible accounts	9	8	6
Write-offs of uncollectible accounts	(7)	(7)	(7)
Allowances for collection of receivables at December 31	$ 11	$ 9	$ 8

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	
2018	2017	2018	2017	2018	2017

SDG&E	$	-	$	4	$	98	$	97	$	98	$	101

INCOME TAXES

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

Under the regulatory accounting treatment required for flow-through temporary differences, we recognize:

- regulatory assets to offset deferred income tax liabilities if it is probable that the amounts will be recovered from customers; and
- regulatory liabilities to offset deferred income 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 6.

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, which is recoverable in rates, is recorded in Cost of Electric Fuel and Purchased Power on the Statement 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.

Our plant costs include:

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

In addition, the cost of utility plant includes AFUDC. We discuss AFUDC below.

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 5.

PROPERTY, PLANT AND EQUIPMENT BY MAJOR FUNCTIONAL CATEGORY

(Dollars in millions)

	PP&E at December 31,		Depreciation rates for years ended December 31,		
	2018	2017	2018	2017	2016
Natural gas operations	$ 2,382	$ 2,186	2.44%	2.40%	2.40%
Electric distribution	7,462	6,975	3.91	3.92	3.86
Electric transmission(1)	6,222	5,626	2.76	2.71	2.66
Electric generation(2)	2,999	2,470	4.12	4.05	4.00
Other electric(3)	1,408	1,114	6.43	5.54	5.66
Construction work in progress(1)	1,221	1,451	NA	NA	NA
Total SDG&E	21,694	19,822			

(1) *At December 31, 2018, includes $457 million in electric transmission assets and $26 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 its Statement of Operations.*

(2) *Includes capital lease assets of $1,902 million and $1,352 million at December 31, 2018 and 2017, respectively.*

(3) *Includes capital lease assets of $13 million and $22 million at December 31, 2018 and 2017, 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

(Dollars in millions)

	Years ended December 31,		
	2018	2017	2016
SDG&E	$ 655	$ 593	$ 548

ACCUMULATED DEPRECIATION *(Dollars in millions)*	December 31,	
	2018	2017
Accumulated depreciation:		
Electric(1)	$ 4,572	$ 4,195
Natural gas	794	756
Total SDG&E	5,366	4,951

(1) Includes accumulated depreciation for capital lease assets of $330 million and $288 million at December 31, 2018 and 2017, respectively. Includes $252 million at December 31, 2018 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.

Interest capitalized and AFUDC are as follows:

CAPITALIZED FINANCING COSTS *(Dollars in millions)*	Years ended December 31,		
	2018	2017	2016
SDG&E	$ 82	$ 85	$ 62

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 entities. 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; and
- 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 AROs 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. We 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 AROs related to various assets, including:

- fuel and storage tanks
- natural gas transmission and distribution systems
- hazardous waste storage facilities
- asbestos-containing construction materials
- nuclear power facilities
- electric transmission and distribution systems
- energy storage systems
- power generation plants

The changes in ARO are as follows:

CHANGES IN ASSET RETIREMENT OBLIGATIONS
(Dollars in millions)

	2018	2017
Balance as of January 1	$ 837	$ 828
Accretion expense	39	39
Liabilities incurred	—	17
Deconsolidation and reclassification	—	—
Payments	(39)	(61)
Revisions	35	14
Balance at December 31	$ 872	$ 837

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; and
- unrealized gains or losses on available-for-sale securities.

The Statement of Comprehensive Income (Loss) show 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:

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) BY COMPONENT (1)

(Dollars in millions)

	Pension and other postretirement	Total accumulated other

	benefits	comprehensive income (loss)
SDG&E:		
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)
OCI before reclassifications	(6)	(6)
Amounts reclassified from AOCI	4	4
Net OCI	(2)	(2)
Balance as of December 31, 2018	$ (10)	$ (10)

(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 other comprehensive income (loss) components	Amounts reclassified from accumulated other comprehensive income (loss)			Affected line item on Statement of Operations
	Years ended December 31,			
	2018	2017	2016	
Pension and other postretirement benefits:				
Amortization of actuarial loss(1)	$ 1	$ 1	$ 1	Other Income, Net
Settlements	4	—	—	Other Income, Net
Total before income tax	5	1	1	
	(1)	—	—	Income Tax Expense
Net of income tax	$ 4	$ 1	$ 1	
Total reclassifications for the period, net of tax	$ 4	$ 1	$ 1	

(1) *Amounts are included in the computation of net periodic benefit cost (see “Net Periodic Benefit Cost” in Note 7).*

REVENUES

See Note 3 for a description of significant accounting policies for revenues.

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, 2018	December 31, 2017
Sempra Energy	$ (43)	$ (30)
SoCalGas	(6)	(4)
Various affiliates	(12)	(6)
Total due to unconsolidated affiliates – current	$ (61)	$ (40)
Income taxes due from Sempra Energy(1)	$ 5	$ 27

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

The following table summarizes revenues and cost of sales from unconsolidated affiliates.

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

	Years ended December 31, 2018	2017	2016
Revenues:	$ 5	$ 8	$ 7
Cost of Sales:	$ 73	$ 71	$ 64

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 effective 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, which, as a lessee, SDG&E accounts for as an operating lease. Energía Sierra Juárez is a 50-percent owned and unconsolidated JV of Sempra Mexico.

RESTRICTED NET ASSETS

The CPUC's regulation of our capital structure limits the amount available for dividends and loans to Sempra Energy. At December 31, 2018, Sempra Energy could have received combined loans and dividends of approximately $552 million.

The payment and amount of future dividends are at the discretion of our boards of directors. The following restrictions limit the amount of retained earnings that may be paid as common stock dividends or loaned to Sempra Energy:

- The CPUC requires that our common equity ratios be no lower than one percentage point below the CPUC-authorized percentage of our authorized capital structure. Our authorized percentage at December 31, 2018 is 52 percent.
- The FERC requires us 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 5.

Based on these restrictions, at December 31, 2018, SDG&E's restricted net assets were $5.5 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,

	2018	2017(1)	2016(1)
Allowance for equity funds used during construction	$ 61	$ 63	$ 46
Non-service component of net periodic benefit (cost) credit	(6)	4	14
Interest on regulatory balancing accounts, net	4	3	3
Sundry, net	(5)	(2)	1
Total	$ 54	$ 68	$ 64

(1) *As adjusted for the retrospective adoption of ASU 2017-07, which we discuss in Note 2.*

NOTE 2. NEW ACCOUNTING STANDARDS

We describe below recent accounting 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.

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 are included in Note 3.

ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities" and ASU 2018-03, "Technical Corrections and Improvements to Financial Instruments – Overall": 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 NAV 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. ASU 2018-03 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. 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.

We adopted ASU 2016-01 and ASU 2018-03 on January 1, 2018. These adoptions did not materially affect our financial condition, results of operation or cash flows.

ASU 2016-02, "Leases," ASU 2018-01, "Land Easement Practical Expedient for Transition to Topic 842," ASU 2018-10, "Codification Improvements to Topic 842, Leases," ASU 2018-11, "Leases (Topic 842): Targeted Improvements" and ASU 2018-20, "Narrow-Scope Improvements for Lessors" (collectively referred to as the "lease standard"): ASU 2016-02 requires entities to recognize substantially all of their leases on the balance sheet as ROU assets and lease liabilities. Entities may elect to exclude from the balance sheet those leases with a term of 12 months or less. For lessees, a lease is classified as finance or operating, and initially the asset and liability for each lease type is generally measured at the present value of the fixed lease payments. ASU 2016-02 also requires new qualitative and quantitative disclosures for both lessees and lessors. ASU 2018-10 makes technical corrections and clarifications to the accounting guidance in ASC 842.

For lessors, accounting for leases is largely unchanged from previous provisions of U.S. GAAP, other than certain changes to the lease identification criteria and aligning the principles of the lessor model with those introduced in ASC 606. ASU 2018-20 addresses the following issues that lessors encounter when applying ASU 2016-02: (a) sales taxes and other similar taxes collected from lessees, (b) certain lessor costs paid directly by the lessee and (c) recognition of variable payments for contracts with lease and nonlease components.

For public entities, the lease standard is effective for fiscal years beginning after December 15, 2018, including interim periods therein, with early adoption permitted. 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. ASU 2018-11 provides entities an optional transition method to apply the new guidance as of the adoption date, rather than as of the earliest period presented. In transition, entities may elect certain practical expedients when applying ASU 2016-02. These include a package of practical expedients that must be applied in its entirety to all leases that had commenced before the effective date and would allow an entity to not reassess (a) the existence of a lease, (b) lease classification or (c) determination of initial direct costs, which effectively allows entities to carryforward accounting conclusions under previous U.S. GAAP. ASU 2016-02 also includes a practical expedient to use hindsight in making judgments when determining the lease term and any long-lived asset impairment. ASU 2018-01 allows entities to elect a 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. In addition, ASU 2016-02 and ASU 2018-11 provide practical expedients to the lessee and lessor, respectively, for separating lease and non-lease components. These ASUs are codified in ASC 842.

We will adopt the lease standard on January 1, 2019 using the optional transition method to apply the new guidance prospectively as of January 1, 2019, rather than as of the earliest period presented. We plan to elect the package of practical expedients and the land easement practical expedient described above. We do not plan to elect the practical expedient to use hindsight.

The adoption of the lease standards will not change our previously reported financial statements. However, on a prospective basis, a significant portion of finance lease costs for PPAs that have historically been classified in Cost of Electric Fuel and Purchased Power will be classified in Depreciation and Amortization Expense and Interest Expense on SDG&E's statement of operations. In 2018, we recorded $117 million in purchased-power costs from capital leases in Cost of Electric Fuel and Purchased Power. Further, the adoption of the lease standard will have a material impact on our balance sheets at January 1, 2019 due to the initial recognition of ROU assets and lease liabilities for operating leases. Our finance leases were already included on our balance sheets prior to adoption of the lease standard, consistent with previous U.S. GAAP for capital leases. We will include additional disclosures about our leases in our Notes to Financial Statements beginning in the first quarter of 2019.

The following table shows the expected (decrease) increase on our balance sheets at January 1, 2019 from adoption of the lease standard.

EXPECTED IMPACT FROM ADOPTION OF THE LEASE STANDARD
(Dollars in millions)

Right-of-use assets - operating leases	$ 130
Other current liabilities	20
Deferred credits and other	110

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, including interim periods therein, with early adoption permitted for fiscal years beginning after December 15, 2018. The amendments are to be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings at the beginning of the first reporting period in the year of adoption. We are currently evaluating the effect of the standard on our ongoing financial reporting and plan to adopt the standard on January 1, 2020.

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. We adopted the standard in conjunction with our adoption of ASC 606 on January 1, 2018 using the modified retrospective transition method and it did not materially affect 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. 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 disclosure in the comparative periods as appropriate estimates when retrospectively changing the presentation of these costs in the statements of operations. We adopted the standard on January 1, 2018 and elected the practical expedient available under the transition guidance.

Upon adoption of ASU 2017-07, our Statement of Operations was impacted as follows:

IMPACT FROM ADOPTION OF ASU 2017-07

(Dollars in millions)

	Years ended December 31,					
	2017			2016		
	As previously reported	Effect of adoption	As adjusted	As previously reported	Effect of adoption	As adjusted
Operation and maintenance	$ 1,003	$ 4	$ 1,007	$ 1,019	$ 14	$ 1,033
Total operating expenses	3,798	4	3,802	3,279	14	3,293
Operating income	680	(4)	676	975	(14)	961
Other income, net	64	4	68	50	14	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. 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 did 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 will adopt ASU 2018-02 on January 1, 2019 and will reclassify the income tax effects of the TCJA from AOCI to retained earnings.

We expect the impact from adoption of ASU 2018-02 on January 1, 2019 to be an increase of $2 million to beginning Retained Earnings and Accumulated Other Comprehensive Loss.

ASU 2018-05, "Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118": As a result of the TCJA, the SEC staff issued Staff Accounting Bulletin No. 118 (SAB 118), which provides guidance on accounting for the TCJA's impact. Under SAB 118, an entity may apply an approach similar to the measurement period in a business combination. That is, an entity would record those impacts for which the accounting is complete. For matters that are not certain, the entity would either (a) recognize provisional amounts to the extent that they are reasonably estimable and adjust them over time as more information becomes available, or (b) for any specific income tax effects of the TCJA for which a reasonable estimate cannot be determined, continue to apply ASC 740, *Income Taxes*, on the basis of the provisions of the tax laws that were in effect immediately before the TCJA was signed into law; the entity would not adjust current or deferred income taxes for those tax effects of the TCJA until a reasonable estimate can be determined. ASU 2018-05 amends ASC 740 by incorporating SAB 118 and was effective upon issuance. We applied SAB 118 and

ASU 2018-05 in 2018. The income tax effects of the TCJA that we recorded in 2017 were provisional. We adjusted our provisional estimates and completed our accounting for the income tax effects of the TCJA in 2018, as we discuss in Note 6.

ASU 2018-13, "Changes to the Disclosure Requirements for Fair Value Measurement" and ASU 2018-14, "Changes to the Disclosure Requirements for Defined Benefit Plans": ASU 2018-13 and ASU 2018-14 are intended to improve the effectiveness of disclosures. ASU 2018-13 adds, removes and modifies certain disclosure requirements related to fair value measurements. ASU 2018-14 adds, removes and clarifies certain disclosure requirements related to defined benefit pension and other postretirement plans. For public entities, ASU 2018-13 is effective for annual reporting periods beginning after December 15, 2019, including interim periods therein, with early adoption permitted. For public entities, ASU 2018-14 is effective for annual reporting periods ending after December 15, 2020, with early adoption permitted. We adopted both ASU 2018-13 and ASU 2018-14 on December 31, 2018 and have updated our financial statement disclosures accordingly.

NOTE 3. REVENUES

The following table disaggregates our revenues from contracts with customers by major service line, market and timing of recognition and provides a reconciliation to total revenues by segment.

DISAGGREGATED REVENUES
(Dollars in millions)

	Year ended December 31, 2018
By major service line:	
Utilities	$ 4,790
Midstream	—
Renewables	—
Other	—
Revenues from contracts with customers	$ 4,790
By market:	
Electric	$ 4,299
Gas	491
Revenues from contracts with customers	$ 4,790
By timing of recognition:	
Over time	$ 4,679
Point in time	111
Revenues from contracts with customers	$ 4,790
Revenues from contracts with customers	$ 4,790
Utilities regulatory revenues	(220)
Other revenues	—
Total revenues	$ 4,570

REVENUES FROM CONTRACTS WITH CUSTOMERS

Our revenues from contracts with customers are primarily related to the generation, transmission and distribution of electricity and the transmission, distribution and storage of natural gas through our regulated utilities. We also provide other midstream and renewable energy-related services. We assess our revenues on a contract-by-contract basis as well as a portfolio basis to determine the nature, amount, timing and uncertainty, if any, of revenues being recognized.

We generally recognize revenues when performance of the promised commodity service is provided to our customers and invoice our customers for an amount that reflects the consideration we are entitled to in exchange for those services. We consider the delivery and transmission of electricity and natural gas and providing of natural gas storage services as ongoing and integrated services. Generally, electricity or natural gas services are received and consumed by the customer simultaneously. Our performance obligations related to these services are satisfied over time and represent a series of distinct services that are substantially the same and that have the same pattern of transfer to the customers. We recognize revenue based on units delivered, as the satisfaction of our performance obligations can be directly measured by the amount of electricity or natural gas delivered to the customer. In most cases, the right to consideration from the customer directly corresponds to the value transferred to the customer and we recognize revenue in the amount that we have the right to invoice. We provide further details of our revenue streams below.

The payment terms in our customer contracts vary. Typically, we have an unconditional right to customer payments, which are due after the performance obligation to the customer is satisfied. The term between invoicing and when payment is due is typically between 10 and 90 days.

We have elected the practical expedient to exclude sales and usage-based taxes from revenues. In addition, we pay franchise fees to operate in various municipalities. We bill these franchise fees to our customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of our ability to collect from the customer, are accounted for on a gross basis and reflected in utilities revenues from contracts with customers and operating expense.

Utilities Revenues

Utilities revenues consist of generation, transmission and distribution of electricity, transmission, distribution and storage of natural gas.

Utilities revenues are derived from and recognized upon the delivery of electricity or natural gas services to customers. Amounts that we bill our customers are based on tariffs set by regulators within the respective state or country. For SDG&E, which follow the provisions of U.S. GAAP governing rate-regulated operations as we discuss in Note 1, amounts that we bill to customers also include adjustments for previously recognized regulatory revenues.

We recognize revenues based on regulator-approved revenue requirements, which allows us to recover our reasonable cost of O&M and provides the opportunity to realize our authorized rates of return on our investments. While our revenues are not affected by actual sales volumes, the pattern of our revenue recognition during the year is affected by seasonality. Our authorized revenue recognition is also impacted by seasonal factors, resulting in higher earnings in the third quarter when electric loads are typically higher than in the other three quarters of the year.

SDG&E has an arrangement to provide the California ISO with the ability to control its high-voltage transmission lines for prices approved by the FERC. Revenue is recognized over time as access is provided to the California ISO.

Factors that can affect the amount, timing and uncertainty of revenues and cash flows include weather, seasonality and timing of customer billings, which may result in unbilled revenues that can vary significantly from month to month and generally approximate one-half month’s deliveries.

We recognize revenues from the sale of allocated California GHG emissions allowances at quarterly auctions administered by CARB. GHG allowances are delivered to CARB in advance of the quarterly auctions, and we have the right to payment when the GHG allowances are sold at auction. GHG revenue is recognized on a point in time basis within the quarter the auction is held. We balance costs and revenues associated with the GHG program through regulatory balancing accounts.

Remaining Performance Obligations

We do not disclose information about remaining performance obligations for (a) contracts with an original expected length of one year or less, (b) revenues recognized at the amount at which we have the right to invoice for services performed, or (c) variable consideration allocated to wholly unsatisfied performance obligations.

For contracts greater than one year, at December 31, 2018, we expect to recognize revenue related to the fixed fee component of the consideration as shown below.

REMAINING PERFORMANCE OBLIGATIONS(1)

(Dollars in millions)		
2019	$	3
2020		3
2021		3
2022		3
2023		3
Thereafter		52
Total revenues to be recognized	$	67

(1) *Excludes intercompany transactions.*

Contract Balances from Revenues from Contracts with Customers

From time to time, we receive payments in advance of satisfying the performance obligations associated with customer contracts. We defer such revenues as contract liabilities and recognize them in earnings as the performance obligations are satisfied.

There were no contract liability activities at SDG&E for the year ended December 31, 2018.

Receivables from Revenues from Contracts with Customers

The table below shows receivable balances associated with revenues from contracts with customers on our Balance Sheet.

RECEIVABLES FROM REVENUES FROM CONTRACTS WITH CUSTOMERS *(Dollars in millions)*				
		December 31, 2018		January 1, 2018
Accounts receivable – trade, net	$	368	$	362
Accounts receivable – other, net		6		3
Due from unconsolidated affiliates – current(1)		3		3
Total	$	377	$	368

(1) *Amount is presented net of amounts due to unconsolidated affiliates on the Balance Sheet, when right of offset exists.*

REVENUES FROM SOURCES OTHER THAN CONTRACTS WITH CUSTOMERS

Certain of our revenues are derived from sources other than contracts with customers and are accounted for under other accounting standards outside the scope of ASC 606.

Utilities Regulatory Revenues

Alternative Revenue Programs

We recognize revenues from alternative revenue programs when the regulator-specified conditions for recognition have been met and adjust these revenues as they are recovered or refunded through future utility service.

Decoupled revenues. As discussed earlier, the regulatory framework requires SDG&E to recover authorized revenue based on estimated annual demand forecasts approved in regular proceedings before the CPUC. However, actual demand for electricity and natural gas will generally vary from CPUC-approved forecasted demand due to the impacts from weather volatility, energy efficiency programs, rooftop solar and other factors affecting consumption. The CPUC regulatory framework provides for SDG&E to use a “decoupling” mechanism, which allows SDG&E to record revenue shortfalls or excess revenues resulting from any difference between actual and forecasted demand to be recovered or refunded in authorized revenue in a subsequent period based on the nature of the account.

Incentive mechanisms. The CPUC applies performance-based measures and incentive mechanisms to all California IOUs, under which SDG&E have earnings potential above authorized base margins if they achieve or exceed specific performance and operating goals. Generally, for performance-based awards, if performance is above or below specific benchmarks, the utility is eligible for financial awards or subject to financial penalties.

Incentive awards are included in revenues when we receive required CPUC approval of the award, the timing of which may not be consistent from year to year. We would record penalties for results below the specified benchmarks against revenues when we believe it is probable that the CPUC would assess a penalty.

Other Cost-Based Regulatory Recovery

The CPUC authorizes SDG&E to collect revenue requirements for costs that they have been authorized to recover from customers, including the costs to purchase electricity and natural gas; costs associated with administering public purpose, demand response, and customer energy efficiency programs; and other programmatic activities authorized as part of the GRC or separately from the GRC. Actual costs are recovered as the commodity or service is delivered or, to the extent actual amounts vary from forecasts, generally recovered or refunded within a subsequent period based on the nature of the account through a balancing account mechanism. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

Because SDG&E’s cost of electricity and natural gas is substantially recovered in rates through a balancing account mechanism, changes in these costs are reflected in the changes in revenues, and therefore do not impact earnings.

The CPUC authorizes balancing accounts for certain programmatic activities. Amounts billed to customers, if any, are recorded in these accounts, as well as actual O&M and applicable capital-related costs (such as depreciation, taxes and ROE). Differences between actual and authorized expenditures are tracked and may be recovered or refunded within a GRC cycle or as part of a subsequent GRC request. Examples of these types of programs include, but are not limited to, gas distribution, gas transmission, and gas storage integrity management. The CPUC may impose various review procedures before authorizing recovery or refund for programs authorized separately from the GRC, including limitations on the total cost of the program, revenue requirement limits or reviews of costs for reasonableness. These procedures could result in disallowances of recovery from ratepayers. An example of a program with reasonableness review procedures is PSEP.

We discuss balancing accounts and their effects further in Note 4.

NOTE 4. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

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

REGULATORY ASSETS (LIABILITIES)
(Dollars in millions)

	December 31, 2018	December 31, 2017
Fixed-price contracts and other derivatives	$ (150)	$ 96
Deferred income taxes refundable in rates	(236)	(281)
Pension and other postretirement benefit plan obligations	186	153
Removal obligations	(1,848)	(1,846)
Unamortized loss on reacquired debt	7	9
Environmental costs	28	29
Sunrise Powerlink fire mitigation	120	119
Regulatory balancing accounts[1]		
Commodity – electric	(8)	82
Gas transportation	45	22
Safety and reliability	70	48
Public purpose programs	(62)	(70)
Other balancing accounts	145	233
Other regulatory liabilities, net[2]	(177)	(70)
Total SDG&E	$ (1,880)	$ (1,476)

(1) *At December 31, 2018 and 2017, the noncurrent portion of regulatory balancing accounts – net undercollected was $78 million and $63 million, respectively.*

(2) *Includes regulatory assets earning a rate of return.*

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 fixed-price contracts and other derivatives further in Note 9.
- 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.

- 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.
- The regulatory asset related to employee benefit costs represents our liability associated with long-term disability insurance that will be recovered from customers in future rates as expenditures are made.
- Regulatory liabilities from removal obligations represent cumulative amounts collected in rates for future asset removal costs in excess of cumulative amounts incurred (or paid).
- Regulatory assets related to unamortized loss on reacquired debt are recovered over the remaining amortization periods of the losses on reacquired debt. These periods range from 1 year to 9 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 13.
- 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 51-year period. We discuss the trust further in Note 13.
- 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, 2018, 2017 and 2016 was $2 million, $49 million and $63 million, respectively, at SDG&E.

CALIFORNIA UTILITIES

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 requirements for 2019 and attrition year adjustments for 2020 through 2022. SDG&E is seeking revenue requirements for 2019 of $2.203 billion, which is an increase of $221 million over their respective 2018 revenue requirement (the 2019 proposed and 2018 actual revenue requirements reflect the impact of various updates made during the course of the proceeding). SDG&E is proposing post-test year revenue requirement annual attrition percentages that are estimated to result in annual increases of approximately 5 percent to 7 percent. The original GRC applications filed in October 2017 did not reflect the impact of the TCJA, which we discuss below in "2016 General Rate Case" and in Note 6. In April 2018, SDG&E updated its application to reflect the impact of the TCJA and filed a proposal to address the impacts. The TCJA impact to SDG&E is a reduction of approximately $58 million to its 2019 test year revenue requirement; however, SDG&E's 2019 requested revenue requirement is unchanged as we evaluate potentially higher costs associated with mitigating wildfire risks.

During the course of the proceeding, Cal PA recommended 2019 revenue requirements of $1.918 billion for SDG&E, which is a net decrease of $64 million compared to the 2018 revenue requirement. Cal PA proposes a three-year annual attrition percentage of 4 percent for SDG&E. Cal PA recommends addressing SDG&E's potential ownership of OMEC in a separate proceeding. As a result, Cal PA's proposed 2019 revenue requirement does not include the estimated $68 million associated with owning and operating the generating facility. SDG&E's potential acquisition of OMEC is subject to a CPUC-approved agreement under which the current owner of the facility can exercise a put option at a designated price. As we discuss in Note 1, SDG&E and OMEC LLC signed a resource adequacy capacity agreement in October 2018, which, if approved by the CPUC on a final and non-appealable basis before the expiration of the put option on April 1, 2019, would result in OMEC LLC waiving its right to exercise the put option. TURN and other intervenors oppose various components of our revenue requirement requests in the 2019 GRC applications.

As part of the 2019 GRC, the CPUC reviewed 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 application filing in a second interim accountability report filed in October 2017. The stated purpose of the initial interim accountability reports is to provide data and metrics for key safety and risk mitigation areas that will be considered in the 2019 GRC. In October 2018, the CPUC confirmed that the 2014, 2015 and 2016 interim accountability reports were compliant with the requirements and also recommended improvements for subsequent reports.

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

We expect a preliminary decision from the CPUC in the first half of 2019.

Risk Assessment Mitigation Phase Reporting and Impact on the 2019 GRC Application 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. 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. SDG&E included funding requests in its respective 2019 GRC filing for proposed projects or activities outlined in its RAMP report. In April 2018, the CPUC granted SDG&E's motion to close the proceeding as all RAMP procedures had been completed. In December 2018, the CPUC approved a settlement agreement that establishes the required elements for the risk and mitigation analysis to be used in RAMP and GRC proceedings with minor modifications.

Senate Bill 549. SB 549 was signed into law in September 2017 and became effective January 1, 2018. The bill requires 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. Beginning in December 2018, the CPUC began incorporating and will continue to incorporate this requirement into the accountability reports.

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 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 from 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 were ordered to be refunded to customers. Pursuant to this refund requirement, in 2016, SDG&E recorded regulatory liabilities for these amounts, resulting in reductions to revenue of $52 million ($31 million after tax).

The 2016 GRC FD 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 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.

At December 31, 2018, the recorded regulatory liability associated with these tracked amounts totaled $89 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. The tracking accounts will remain open until the CPUC decides to close the accounts, which we expect will be reviewed in the 2019 GRC proceeding.

The 2016 GRC FD revenue requirement was authorized using a federal income tax rate of 35 percent. As a result of the TCJA, the federal income tax rate became 21 percent effective January 1, 2018. Since SDG&E continues to collect authorized revenues based on a 35 percent tax rate, SDG&E is recording revenue deferrals, aligned with authorized seasonality factors, that reflect the estimated reduction in the revenue requirement. As of December 31, 2018, SDG&E recorded regulatory liabilities of $75 million, in anticipation of amounts that will benefit customers in future rates. SDG&E also recorded a $67 million regulatory liability at December 31, 2018, relating to its FERC jurisdictional rates, in anticipation of amounts that will benefit customers in future rates for the decrease in the federal income tax rate.

CPUC Cost of Capital

In September 2017, SDG&E filed an advice letter to update its 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 were anticipated.

In October 2017, the CPUC approved the embedded cost of debt presented in the advice letter filed by SDG&E resulting in a revised return on rate base for SDG&E of 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%		**7.55%**

The changes to the embedded cost of debt and return on rate base resulting from the updates included in the filed advice letter is summarized below:

CHANGES TO THE EMBEDDED COST OF DEBT

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

The costs of long-term debt and the ROEs shown above will remain in effect through December 31, 2019. The cost of capital changes will also apply to capital expenditures in 2019 for incremental projects not funded through the GRC revenue requirement. SDG&E is required to file a cost of capital application by the end of April 2019 for a January 1, 2020 implementation date. The automatic CCM did not operate in 2018 and will be evaluated in the 2019 cost of capital proceeding.

FERC Rate Matters and Cost of Capital

SDG&E files separately with the FERC for its authorized ROE on FERC-regulated elecric 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:

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%**

FERC Formulaic Rate Filing

SDG&E submitted its TO5 filing with the FERC in October 2018 to be effective January 1, 2019, subject to refund. This proceeding will establish the revenue requirement, including rate of return, for SDG&E's FERC-regulated electric transmission operations and assets. SDG&E's TO5 filing proposes to continue most aspects of its existing FERC-authorized formula rate. SDG&E's TO5 filing is requesting: (1) rates to be determined by a base period of historical costs and a forecast of capital investments, (2) a true-up period, which is similar to a balancing account that is designed to provide SDG&E earnings of no more and no less than its actual cost of service including its authorized return on investment, (3) a true-up of accumulated deferred income tax and (4) a refund of amounts collected in rates in 2018 that presumed a 35 percent federal income tax rate. The net impact of our TO5 filing is a revenue requirement of $911 million, an increase in rates of $88 million, or 10.6 percent, above 2018's revenue requirement.

This TO5 proceeding will also set SDG&E's authorized FERC ROE. SDG&E's current authorized FERC ROE is 10.05 percent, and

SDG&E's TO5 filing proposes a FERC ROE of 11.2 percent. On December 31, 2018, the FERC issued its order accepting and suspending the TO5 filing and establishing hearing and settlement judge procedures. In the order, the FERC suspended the TO5 filing for five months, during which the existing TO4 rates will remain in effect. After the suspension period ends, the proposed TO5 rates will take effect, subject to refund and the outcome of the hearing and settlement judge procedures. A FERC settlement judge has been appointed, and we expect settlement conferences to begin in the first quarter of 2019.

NOTE 5. DEBT AND CREDIT FACILITIES

LINES OF CREDIT

SDG&E and SoCal Gas 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, 2018			
	Total facility	Commercial paper outstanding (1)	Adjustment for combined limit	Available unused credit
California Utilities (2):				
SDG&E	$ 750	$ (291)	$ (6)	$ 453
SoCalGas	750	(256)	(41)	453
Less: subject to a combined limit of $1 billion for both utilities	(500)	—	47	(453)
Total	$ 1,000	$ (547)	$ —	$ 453

(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, 2018.*

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

- Each is a 5-year syndicated revolving credit agreement expiring in October 2020.
- 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, 2018.
- 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 rates on total short-term debt at SDG&E were 2.97 percent and 1.65 percent at December 31, 2018 and 2017, respectively.

LONG-TERM DEBT

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

LONG-TERM DEBT
(Dollars in millions)

	December 31, 2018	December 31, 2017
First mortgage bonds (collateralized by plant assets):		
1.65% July 1, 2018[1]	$ —	$ 161
3% August 15, 2021	350	350
1.914% payable 2015 through February 2022	125	161
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	400
4.15% May 15, 2048	400	—
	4,776	4,573
Capital lease obligations:		
Purchased-power contracts	1,583	1,085
Other	2	1
	1,585	1,086
	6,361	5,659
Current portion of long-term debt	(366)	(251)
Unamortized discount on long-term debt	(12)	(11)
Unamortized debt issuance costs	(35)	(33)
Total SDG&E	5,948	5,364

MATURITIES OF LONG-TERM DEBT[1] *(Dollars in millions)*	
2019	$ 36
2020	36
2021	386
2022	18
2023	450
Thereafter	3,850
Total	$ 4,776

(1) *Excludes capital lease obligations, discounts, premiums and debt issuance costs.*

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, 2018 is callable subject to premiums:

CALLABLE LONG-TERM DEBT *(Dollars in millions)*	
Not subject to make-whole provisions	$ 251
Subject to make-whole provisions	4,525

FIRST MORTGAGE BONDS

We issue first mortgage bonds secured by a lien on utility plant assets. We may issue additional first mortgage bonds if in compliance with the provisions of their bond agreements (indentures). These indentures require, among other things, the satisfaction of pro forma earnings-coverage tests on first mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of additional first mortgage bonds of $5.7 billion at SDG&E at December 31, 2018.

In May 2018, SDG&E publicly offered and sold $400 million of 4.15-percent, first mortgage bonds maturing in 2048. SDG&E used the proceeds from the offering to repay outstanding commercial paper.

OTHER LONG-TERM DEBT

In 2017, SDG&E satisfied all of the conditions precedent for a CPUC-approved 20-year PPA with a 500-MW power plant facility. Construction of the facility was completed and delivery of contracted power commenced in December 2018, at which time we recorded a $550 million capital lease obligation on SDG&E’s Balance Sheet.

NOTE 6. INCOME TAXES

We provide our calculations of ETRs in the following table.

INCOME TAX EXPENSE AND EFFECTIVE INCOME TAX RATES
(Dollars in millions)

	Years ended December 31,		
	2018	2017	2016
Income tax expense	$ 173	$ 155	$ 280
Income before income taxes	$ 842	$ 562	$ 850
Effective income tax rate	21%	28%	33%

We present in the table below a reconciliation of net U.S. statutory federal income tax rates to our ETRs.

RECONCILIATION OF FEDERAL INCOME TAX RATES TO EFFECTIVE INCOME TAX RATES

	Years ended December 31,		
	2018	2017	2016
U.S. federal statutory income tax rate	21%	35%	35%
State income taxes, net of federal income tax benefit	5	3	5
Depreciation	3	7	5
Effects of the TCJA	—	5	—
Resolution of prior years' income tax items	—	(4)	(1)
Compensation-related items	—	—	(1)
Repairs expenditures	(3)	(8)	(4)
Self-developed software expenditures	(2)	(6)	(3)
Allowance for equity funds used during construction	(2)	(4)	(2)
Amortization of excess deferred income taxes	(1)	—	—
Other, net	—	—	(1)
Effective income tax rate	21%	28%	33%

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

The TCJA reduced the U.S. statutory corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. 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 in 2017.

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. As we discuss in Note 4, these excess deferred income taxes have been recorded as regulatory liabilities at December 31, 2018 and 2017 and will generally be refunded to ratepayers in accordance with the IRC's normalization provisions and as determined by the CPUC and the FERC. Certain components of deferred income taxes could be attributed to shareholders rather than ratepayers. These components include deferred income taxes generated by activities outside of ratemaking.

We recorded the effects of the TCJA in 2017 using our best estimates and the information available to us through the date those financial statements were issued. In 2018, we adjusted our 2017 provisional estimates and completed our accounting for the income tax effects of the TCJA as permitted by ASU 2018-05, which we describe in Note 2. The primary impacts of the TCJA recorded in 2017 and the related 2018 adjustments were:

Lower U.S. statutory corporate income tax rate: We remeasured our deferred income tax balances because of the change in the U.S. statutory corporate federal income tax rate from 35 percent to 21 percent. SDG&E's impacts were primarily offset with adjustments to regulatory liabilities; however, SDG&E also recorded $28 million of income tax expense for the year ended December 31, 2017.

The table below summarizes the effects of the TCJA at December 31, 2017 by FERC account and jurisdiction:

TCJA REMEASUREMENT - REDUCTION TO DEFERRED INCOME TAX BALANCES

(Dollars in millions)

	FERC ACs 182.3/254	FERC AC 190(1)	FERC AC 282	FERC AC 283(2)	Total Deferred	FERC AC 410 (Exp)
FERC	$ 599	$ 5	$ (421)	$ (183)	$ (599)	
CPUC	$ 829	$ 6	$ (474)	$ (361)	$ (829)	
Shareholder		$ 2	$ 26		$ 28	$ (28)
Total	$ 1,428	$ 13	$ (869)	$ (544)	$ (1,400)	$ (28)

(1) Since account 190 is an asset, the decrease in this table is shown as positive. Does not include the Net Operating Loss Deferred Tax Asset related to FERC Transmission.

(2) Account 283 includes approximately $500 million of gross-up required under ASC 740 on flow-through deferred taxes and gross-up on excess deferred taxes.

In the first quarter of 2018, there was a true up to the remeasurement in the amount of $38M primarily related to ASC 740, *Income taxes*, gross-up on flow-through deferred taxes. This resulted in additional reduction of deferred tax liabilities and an increase in net regulatory liabilities.

The amount of excess deferred income taxes related to plant in service (excluding gross-up) that is considered protected and unprotected as of December 31, 2018 and 2017 is reflected below:

TOTAL COMPANY EXCESS DEFERRED INCOME TAXES FOR PLANT IN SERVICE (1)

(Dollars in millions)

		2018		2017
FERC - Protected	$	382	$	384
CPUC - Protected	$	463	$	469
FERC - Unprotected	$	3	$	6
CPUC - Unprotected	$	(120)	$	(122)
Total	$	728	$	737

(1) *Does not include the Net Operating Loss Deferred Tax Asset related to FERC Transmission.*

At December 31, 2018, SDG&E has not received a regulatory order from the FERC or CPUC regarding how customer rates should be reduced for excess deferred income taxes. Future potential regulatory orders and IRS guidance could impact the classification of protected and unprotected amounts indicated above. For plant in service, excess deferred income taxes will be amortized over the book life of the underlying property. The annual amortization will be computed using the Average Rate Assumption Method (ARAM).

Under ARAM, we reduced our regulatory liability related to excess deferred income taxes by $9 million, excluding gross-up. The reduction in the excess deferred income tax regulatory liability (FERC AC 254) was offset against deferred income taxes (FERC AC 411.1). This adjustment has been reflected in the following FERC accounts as of December 31, 2018:

ARAM - REGULATORY LIABILITY/DEFERRED INCOME TAXES

(Dollars in millions)

		December 31, 2018	Amortization Period
FERC ACs 254 / 411.1			
FERC - Protected	$	2	Book Depreciation Life
CPUC - Protected	$	6	Book Depreciation Life
FERC - Unprotected	$	3	Book Depreciation Life
CPUC - Unprotected	$	(2)	Book Depreciation Life
Total	$	9	

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 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, which is non-taxable;
- 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; and
- state income taxes.

The 2016 GRC FD 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. We discuss the tracking accounts further in Note 4.

The components of income tax expense are as follows.

INCOME TAX EXPENSE (BENEFIT)
(Dollars in millions)

	Years ended December 31,		
	2018	2017	2016
Current:			
U.S. federal	$ 104	$ 100	$ —
U.S. state	30	65	22
Total	134	165	22
Deferred:			
U.S. federal	17	29	223
U.S. state	24	(41)	38
Total	41	(12)	261
Deferred investment tax credits	(2)	2	(3)
Total income tax expense	$ 173	$ 155	$ 280

The table below presents the components of deferred income taxes:

DEFERRED INCOME TAXES
(Dollars in millions)

	December 31,	
	2018	2017
Deferred income tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 1,578	$ 1,472
Regulatory balancing accounts	84	113
Property taxes	29	26
Other	10	10
Total deferred income tax liabilities	1,701	1,621
Deferred income tax assets:		
Tax credits	6	7
Postretirement benefits	58	43
Compensation-related items	5	5
State income taxes	6	14
Accrued expenses not yet deductible	4	3
Other	6	19
Total deferred income tax assets	85	91
Net deferred income tax liability	$1,616	$1,530

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)

	2018	2017	2016
Balance at January 1	$ 10	$ 22	$ 20
Increase in prior period tax positions	1	9	—
Decrease in prior period tax positions	—	(11)	—
Increase in current period tax positions	—	—	2
Settlements with taxing authorities	—	(10)	—
Balance at December 31	$ 11	$ 10	$ 22
Of December 31 balance, amounts related to tax positions that if recognized in future years would			
decrease the effective tax rate(1)	$ (9)	$ (7)	$ (19)
increase the effective tax rate(1)	1	1	13

(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,		
	2018	2017	2016
Expiration of statutes of limitations on tax assessments	$ —	$ —	$ (1)
Potential resolution of audit issues with various U.S. federal, state and local taxing authorities	(6)	(6)	(10)
	$ (6)	$ (6)	$ (11)

Amounts accrued for interest associated with unrecognized income tax benefits are included in Income Tax Expense on the Statement of Operations. SDG&E accrued negligible amounts for interest expense at December 31, 2018 and 2017 on the Balance Sheet, and recorded negligible amounts of interest expense in each of 2018, 2017 and 2016 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 2014 and by state tax jurisdictions for tax years after 2008.

NOTE 7. EMPLOYEE BENEFIT PLANS

For our employee benefit plans, we:

- 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; 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 primarily 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 $416 million and $455 million at December 31, 2018 and 2017, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Benefit Plan Amendments Affecting 2018

In 2018, certain executive participants in a company nonqualified pension plan became eligible in this same plan for Supplemental Executive Retirement Plan benefits. This was treated as a plan amendment and increased the recorded pension liability by $8 million at SDG&E.

Sale of Qualified Pension Plan Annuity Contracts

In March 2018, an insurance company purchased annuities for certain current annuitants in the SDG&E qualified pension plans and assumed the obligation for payment of these annuities. At SDG&E in the first quarter of 2018, the liability transferred for these annuities, plus the total year-to-date lump-sum payments, exceeded the settlement threshold, which triggered settlement accounting. This resulted in a reduction of the recorded pension liability and pension plan assets of $132 million at SDG&E. This also resulted in settlement charges in net periodic benefit cost of $22 million at SDG&E. The settlement charges were recorded as regulatory assets on the Balance Sheet.

Settlement Accounting for Lump Sum Payments

In 2018, SDG&E recorded settlement charges of $4 million for lump sum payments from its non-qualified pension plans that were in excess of the respective plan's service cost plus interest cost, thereby triggering settlement accounting.

Special Termination Benefits Affecting 2018, 2017 and 2016

In 2018 and 2016, certain nonrepresented, and in 2017, certain represented, 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 these 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 $3 million in 2018 and $14 million 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 in 2016, were recorded as regulatory assets on the Balance Sheet. A measurement date of December 31, 2016 was used for the respective settlement accounting triggered in that year, as the year-to-date lump-sum benefit payments first exceeded the settlement threshold in December of that year.

Benefit Obligations and Assets

The following table provides a reconciliation of the changes in the plans' projected benefit obligations and the fair value of assets during 2018 and 2017, and a statement of the funded status at December 31, 2018 and 2017:

PROJECTED BENEFIT OBLIGATION, FAIR VALUE OF ASSETS AND FUNDED STATUS

(Dollars in millions)

	Pension benefits		Other postretirement benefits	
	2018	2017	2018	2017
CHANGE IN PROJECTED BENEFIT OBLIGATION				
Net obligation at January 1	$ 971	$ 935	$ 185	$ 190
Service cost	30	29	5	5
Interest cost	35	38	7	8
Contributions from plan participants	—	—	8	7
Actuarial loss (gain)	(63)	50	(17)	(9)
Plan amendments	8	—	—	—
Benefit payments	(22)	(83)	(21)	(16)
Special termination benefits	—	—	3	—
Settlements	(145)	—	—	—
Transfer of liability from (to) other plans	—	2	—	—
Net obligation at December 31	814	971	170	185
CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	776	714	195	169
Actual return on plan assets	(56)	120	(12)	30
Employer contributions	47	22	2	5
Contributions from plan participants	—	—	8	7
Benefit payments	(22)	(83)	(21)	(16)
Settlements	(145)	—	—	—
Transfer of assets from other plans	—	3	—	—
Fair value of plan assets at December 31	600	776	172	195
Funded status at December 31	$ (214)	$ (195)	$ 2	$ 10
Net recorded (liability) asset at December 31	$ (214)	$ (195)	$ 2	$ 10

Actuarial (gains) losses 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 2018, 2017 and 2016, 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 SDGE's actual mortality experience, in our calculations for each of those years. Actuarial gains in 2018 in pension plans were driven primarily by an increase in discount rates and additionally due to updated census data. The actuarial gains were partially offset by an increase in the interest crediting rate for the cash balance plans. Actuarial gains in PBOP plans were driven primarily by an increase in discount rates.

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 the 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 benefit 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 AOCI 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 decisions by regulatory agencies.

We record annual pension and other postretirement net periodic benefit costs equal to the contributions to their qualified 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	
	2018	2017	2018	2017
Noncurrent assets	$ —	$ —	$ 2	$ 10
Current liabilities	(2)	(13)	—	—
Noncurrent liabilities	(212)	(182)	—	—
Net recorded (liability) asset	$ (214)	$ (195)	$ 2	$ 10

Amounts recorded in AOCI at December 31, 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			
	2018		2017	
Net actuarial loss	$	(4)	$	(8)
Prior service cost		(6)		—
Total	$	(10)	$	(8)

SDG&E has 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)

	2018		2017	
Projected benefit obligation	$	788	$	939
Accumulated benefit obligation		762		900
Fair value of plan assets		600		776

We also have unfunded pension plans at SDG&E. The following table shows the obligations of unfunded pension plans at December 31:

OBLIGATIONS OF UNFUNDED PENSION PLANS
(Dollars in millions)

	2018		2017	
Projected benefit obligation	$	26	$	32
Accumulated benefit obligation		19		30

SDG&E has a funded other postretirement benefit plan.

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		
	2018	2017	2016	2018	2017	2016
NET PERIODIC BENEFIT COST						
Service cost	$ 30	$ 29	$ 29	$ 5	$ 5	$ 5
Interest cost	35	38	41	7	8	7
Expected return on assets	(47)	(47)	(49)	(13)	(11)	(12)
Amortization of:						
Prior service cost	2	1	1	3	3	3
Actuarial loss (gain)	1	9	10	(3)	—	(1)
Settlement charge	26	—	16	—	—	—
Special termination benefits	—	—	—	3	—	14
Net periodic benefit cost	47	30	48	2	5	16
Regulatory adjustment	(8)	(8)	(45)	—	—	(14)
Total net periodic benefit cost	39	22	3	2	5	2
CHANGES IN PLAN ASSETS AND BENEFIT OBLIGATIONS RECOGNIZED IN OCI						
Net loss (gain)	(1)	2	1	—	—	—
Prior service cost	8	—	—	—	—	—
Amortization of actuarial loss	(1)	(1)	(1)	—	—	—
Settlements	(4)	—	—	—	—	—
Total recognized in OCI	2	1	—	—	—	—
Total recognized in net periodic benefit cost and OCI	$ 41	$ 23	$ 3	$ 2	$ 5	$ 2

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

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

Interest crediting rate is based on an average 30-year Treasury bond from the month of November of the preceding year.

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	
	2018	2017	2018	2017
Discount rate	4.29%	3.64%	4.30%	3.65%
Interest crediting rate(1)(2)	3.36	2.80	3.36	2.80
Rate of compensation increase	2.00-10.00	2.00-10.00	2.00-10.00	2.00-10.00

(1) *Interest crediting rate for pension benefits applies only to funded cash balance plans.*

(2) *Interest crediting rate for other postretirement benefits applies only to interest bearing health retirement accounts.*

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

	Pension benefits			Other postretirement benefits		
	2018	2017	2016	2018	2017	2016
Discount rate	3.64%	4.08%	4.35%	3.65%	4.15%	4.50%
Expected return on plan assets	7.00	7.00	7.00	6.94	6.91	6.90
Interest crediting rate(1)(2)	2.80	2.86	3.03	2.80	2.86	3.03
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

(1) *Interest crediting rate for pension benefits applies only to funded cash balance plans.*

(2) *Interest crediting rate for other postretirement benefits applies only to interest bearing health retirement accounts.*

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		
	2018	2017	2016	2018	2017	2016
Health care cost trend rate assumed for next year	6.50%	7.00%	8.00%	4.75%	5.00%	5.50%
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	4.75%	5.00%	5.00%	4.50%	4.50%	4.50%
Year the rate reaches the ultimate trend	2025	2022	2022	2022	2022	2022

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:

- 35 percent domestic equity;
- 24 percent international equity;
- 18 percent long credit;
- 8 percent ultra-long duration government securities;
- 5 percent global real estate investment trusts;
- 5 percent return-seeking credit; and
- 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; and
- 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 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 flow 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 flow 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 – Futures contracts that are publicly traded in active markets are valued at closing prices as of the last business day of the year. 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 futures 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 10. 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.

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, 2018

	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Equity securities:			
Domestic	$ 727	$ —	$ 727
International	437	—	437
Registered investment companies	74	—	74
Fixed income securities:			
Domestic government bonds	197	29	226
International government bonds	—	8	8
Domestic corporate bonds	—	311	311
International corporate bonds	—	53	53
Registered investment companies	—	1	1
Total investment assets in the fair value hierarchy	$ 1,435	$ 402	$ 1,837
Investments measured at NAV:			
Common/collective trusts			326
Private equity funds			4
Total investment assets(1)			$ 2,167
SDG&E's proportionate share of investment assets			$ 602
SoCalGas' proportionate share of investment assets			$ 1,389

	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(2)			$ 2,664
SDG&E's proportionate share of investment assets			$ 777
SoCalGas' proportionate share of investment assets			$ 1,697

(1) *Excludes cash and cash equivalents of $14 million and accounts payable of $21 million.*

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

The fair values by asset category of the PBOP plan assets held in the pension master trust and in the additional trusts for 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, 2018		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 37	$ —	$ 37
International	22	—	22
Registered investment companies	59	—	59
Fixed income securities:			
Domestic government bonds	10	1	11
Domestic corporate bonds	—	16	16
International corporate bonds	—	3	3
Registered investment companies	—	7	7
Total investment assets in the fair value hierarchy	128	27	155
Investments measured at NAV – Common/collective trusts			17
Total investment assets(1)			172

(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, 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.

Future Payments

We expect to contribute the following amounts to our pension and PBOP plans in 2019:

EXPECTED CONTRIBUTIONS

(Dollars in millions)

Pension plans	$	40
Other postretirement benefit plans		—

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
2019	$ 109	$ 10
2020	69	10
2021	64	10
2022	61	11
2023	62	11
2024-2028	282	51

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 the respective governmental authorities.

Employer contributions to the savings plans were as follows:

EMPLOYER CONTRIBUTIONS TO SAVINGS PLANS
(Dollars in millions)

	2018	2017	2016
SDG&E	$ 15	$ 14	$ 15

The market value of Sempra Energy common stock held by the savings plans was $1.0 billion and $1.1 billion at December 31, 2018 and 2017, respectively.

NOTE 8. 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; and
- 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, 2018, 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 or in accordance with the terms of the grant. Options are subject to forfeiture or earlier expiration following termination of employment, subject to certain exceptions.
- *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 (for awards granted prior to 2015) 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 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 and 2018 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.

- *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 through 2018) or four-year service periods (for awards granted prior to 2015).
- *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, 2018, 6,067,767 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, for awards granted to retirement-eligible participants, the expense is recognized over the initial year in which the award was granted. For awards granted to participants who become eligible for retirement during the requisite service period, the expense is recognized over the period between the date of grant and the later of the end of the year in which the award was granted or the date the participant first becomes eligible for retirement. 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. 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.

Sempra Energy subsidiaries record an expense for the plans to the extent that subsidiary 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 SDG&E's share-based awards was comprised as follows:

SHARE-BASED COMPENSATION EXPENSE
(Dollars in millions)

	Years ended December 31,		
	2018	2017	2016
Share-based compensation expense, before income taxes	$ 12	$ 13	$ 7
Income tax benefit	(3)	(5)	(3)
	$ 9	$ 8	$ 4
Capitalized share-based compensation cost	$ 6	$ 5	$ 4
Excess income tax benefit	$ 3	—	$ (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.

The following table shows a summary of non-qualified stock options at December 31, 2018 and activity for the year then ended:

NON-QUALIFIED STOCK OPTIONS

	Common shares under option	Weighted-aveerage exercise price	Weighted-average remaining contractural term (in years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2018	195.801	$ 50.30		
Exercised	(138,861)	$ 48.53		
Outstanding at December 31, 2018	56,940	$ 54.63	0.9	$ 3
Vested at December 31, 2018	56,940	$ 54.63	0.9	$ 3
Exercisable at December 31, 2018	56,940	$ 54.63	0.9	$ 3

The aggregate intrinsic value at December 31, 2018 is the total of the difference between Sempra Energy's closing common stock price and the exercise price for all in-the-money options. The aggregate intrinsic value for non-qualified stock options exercised in the last three years was:

- $9 million in 2018;
- $9 million in 2017; and
- $8 million in 2016.

We have not granted any stock options since 2010, though in January 2019, we granted non-qualified stock options to several executive officers of Sempra Energy. All outstanding stock options at December 31, 2018 are fully vested and compensation cost on such stock options was fully recognized by December 31, 2014.

We received cash of $7 million from stock option exercises during 2018.

NOTE 9. 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 and benchmark interest rate risk. Our use of derivatives for these risks is integrated into the economic management of our anticipated revenues, anticipated expenses, assets and liabilities. Derivatives may be effective in mitigating these risks (1) that could lead to declines in anticipated revenues or increases in anticipated expenses, or (2) that our asset values may fall or our liabilities increase. Accordingly, our derivative activity summarized below generally represents an impact that is intended to offset associated revenues, expenses, assets or liabilities that are not included in the tables below.

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

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

The following table summarizes net energy derivative volumes.

NET ENERGY DERIVATIVE VOLUMES
(Quantities in millions)

Commodity	Unit of measure	December 31, 2018	December 31, 2017
Natural gas	MMBtu	33	39
Electricity	MWh	2	3

Congestion revenue rights	MWh	52	59

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 tables provide the fair values of derivative instruments on the Balance Sheets at December 31, 2018 and 2017, 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, 2018			
	Current assets: Other (1)	Other assets: Sundry	Current liabilities: Other	Deferred credits and other liabilities: Deferred credits and other
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	$ 60	$ 233	$ (37)	$ (72)
Associated offsetting commodity contracts	(6)	(2)	6	2
Associated offsetting cash collateral	—	—	—	2
Net amounts presented on the balance sheet	54	231	(31)	(68)
Additional cash collateral for commodity contracts subject to rate recovery	28	—	—	—
Total(2)	$ 82	$ 231	$ (31)	$ (68)

(1) Included in Current Assets: Fixed-Price Contracts and Other Derivatives.

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

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET
(Dollars in millions)

	December 31, 2017			
	Current assets: Other (1)	Other assets: Sundry	Current liabilities: Other	Deferred credits and other liabilities: Deferred credits and other
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				

Net amounts presented on the balance sheet	26	100	(44)	(115)
Additional cash collateral for commodity contracts subject to rate recovery	16	—	—	—
Total(2)	$ 42	$ 100	$ (44)	$ (115)

(1) Included in Current Assets: Fixed-Price Contracts and Other Derivatives.

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

The following table summarizes the effects of derivative instruments not designated as hedging instruments on the Statement of Operations.

UNDESIGNATED DERIVATIVE IMPACTS
(Dollars in millions)

		Pretax gain (loss) on derivatives recognized in earnings		
		Years ended December 31,		
	Location	2018	2017	2016
Commodity contracts subject to rate recovery	Cost of Electric Fuel and Purchased Power	$ 279	$ 54	$ (53)

CONTINGENT FEATURES

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

For SDG&E, the total fair value of this group of derivative instruments in a net liability position at December 31, 2017 was $1 million.

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 10. 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, 2018 and 2017. 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 9 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 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, 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, 2018 and 2017.

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

	Fair value at December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts:				
Equity securities	$ 407	$ 4	$ —	$ 411
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	43	10	—	53
Municipal bonds	—	269	—	269
Other securities	—	234	—	234
Total debt securities	43	513	—	556
Total nuclear decommissioning trusts(1)	450	517	—	967

Commodity contracts subject to rate recovery	1	6	278	285
Effect of netting and allocation of collateral(2)	23	—	5	28
Total	$ 474	$ 523	$ 283	$ 1,280
Liabilities:				
Commodity contracts subject to rate recovery	2	—	99	101
Effect of netting and allocation of collateral(2)	(2)	—	—	(2)
Total	$ —	$ —	$ 99	$ 99

	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

(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,		
	2018	2017	2016
Balance at January 1	$ (28)	$ (74)	$ 19
Realized and unrealized gains (losses)	209	34	(120)

Allocated transmission instruments	10	6	8
Settlements	(12)	6	19
Balance at December 31	$ 179	$ (28)	$ (74)
Change in unrealized gains (losses) relating to instruments still held at December 31	$ 183	$ 30	$ (101)

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

Inputs used to determine the fair value of CRRs and fixed-price electricity positions are reviewed and compared with market conditions to determine reasonableness. SDG&E expects all costs related to these instruments to be recoverable through customer rates. As such, there is no impact to earnings from changes in the fair value of these instruments.

CRRs are recorded at fair value based almost entirely on the most current auction prices published by the California ISO, an objective source. Annual auction prices are published once a year, typically in the middle of November, and 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, were in the following ranges for the years indicated below:

CONGESTION REVENUE RIGHTS AUCTION PRICE INPUTS

Settlement year	Price per MWh			Median price per MWh
2019	$ (8.57)	to	$ 35.21	$ (2.94)
2018	(7.25)	to	11.99	0.09
2017	(11.88)	to	6.93	(0.14)

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 9.

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. The range and weighted-average price of these inputs was as follows:

LONG-TERM, FIXED-PRICE ELECTRICITY POSITIONS PRICE INPUTS

Settlement year	Price per MWh			Weighted-average price per MWh
2018	$ 22.20	to	$ 76.85	$ 42.69
2017	22.55	to	44.10	35.23

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 9.

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 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, 2018 and 2017:

FAIR VALUE OF FINANCIAL INSTRUMENTS
(Dollars in millions)

	December 31, 2018				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
SDG&E:					
Total long-term debt(1)	$ 4,776	$ —	$ 4,897	$ —	$ 4,897

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

(1) *Before reductions for unamortized discount and debt issuance costs of $47 million and $44 million at December 31, 2018 and 2017, respectively, and excluding capital lease obligations of $1,585 million and $1,086 million at December 31, 2018 and 2017, respectively.*

We provide the fair values for the securities held in the NDT funds related to SONGS in Note 12.

NOTE 11. PREFERRED STOCK

SDG&E is authorized to issue up to 45 million shares of preferred stock, respectively. At December 31, 2018 and 2017, 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 12. 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, as a result of issues with the steam generators used in the facility, 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 SDG&E's Statement of Operations.

SONGS STEAM GENERATOR REPLACEMENT PROJECT

The replacement steam generators, which caused a water leak due to unexpected tube wear, were designed and provided by MHI. In 2013, Edison instituted arbitration proceedings against MHI seeking recovery of damages resulting from the issues with the steam generators used in SONGS Units 2 and 3. The other SONGS co-owners, SDG&E and the City of Riverside, participated as claimants and respondents.

On March 13, 2017, the International Chamber of Commerce International Court of Arbitration Tribunal (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. In accordance with the Amended Settlement Agreement discussed below, SDG&E recorded the proceeds from the MHI arbitration by reducing O&M 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 2012, in response to the SONGS 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 2014, the CPUC issued a final decision approving an Amended Settlement Agreement which provided for various disallowances, refunds and rate recoveries, including authorizing SDG&E to recover in rates its remaining investment in SONGS, excluding its investment in the Steam Generator Replacement Project.

In 2016, the CPUC issued two procedural rulings: the first, to reopen the record of the OII to address the issue of whether the Amended Settlement Agreement is reasonable and in the public interest, and the second, 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.

In July 2018, the CPUC approved a Revised Settlement Agreement among SDG&E, Edison, Cal PA, TURN and other intervenors that resolved all issues under consideration in the SONGS OII and made one modification to the Amended Settlement Agreement to remove the requirement to fund a GHG emissions reduction research program. In August 2018, parties to the Revised Settlement Agreement submitted a notice that they accepted the settlement agreement, as modified.

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.

Disallowances, Refunds and Recoveries

Under the Revised Settlement Agreement, SDG&E and Edison ceased rate recovery of SONGS costs as authorized under the Amended Settlement Agreement as of December 19, 2017, when the present value of their combined remaining SONGS regulatory assets equaled $775 million, of which $152 million represents SDG&E's share. 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. In October 2018, SDG&E began refunding to customers SONGS-related amounts recovered in rates after December 19, 2017.

Utility Shareholder Agreement

In January 2018, SDG&E and Edison entered into the Utility Shareholder Agreement under which 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 mutually released each other from the "SONGS Issues," a defined term that consists of 18 broad categories. The effect of the agreement is that the parties released each other from any and all claims that each party had or could have asserted related to the steam generator replacement failure and its aftermath. The Utility Shareholder Agreement became effective upon CPUC approval of the Revised Settlement Agreement. Edison's payment obligation commenced in October 2018, and amounts are due to SDG&E quarterly thereafter until April 2022. At December 31, 2018, SDG&E has a receivable from Edison, including accrued interest, totaling $124 million, with $40 million classified as current and $84 million classified as noncurrent. 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.

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 and the spent fuel is removed from the site. Edison contracted with a JV 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 Balance Sheet at fair value with the offsetting credits recorded in noncurrent Regulatory Liabilities.

In March 2018, SDG&E and Edison jointly filed an application requesting CPUC approval of revised remaining decommissioning cost estimates (for costs estimated to be incurred in 2018 and beyond) for SONGS Unit 1 of $207 million (in 2014 dollars), of which SDG&E's share is $41 million, and SONGS Units 2 and 3 of $3.2 billion (in 2014 dollars), of which SDG&E's share is $638 million. In addition, SDG&E has estimated internal decommissioning costs (for costs estimated to be incurred in 2018 and beyond) of $3 million (in 2014 dollars) for SONGS Unit 1 and $43 million (in 2014 dollars) for SONGS Units 2 and 3. 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 $455 million for 2013 through 2019 (2019 forecasted) SONGS decommissioning costs. This includes up to $93 million authorized by the CPUC in January 2019 to be withdrawn from the NDT for forecasted 2019 SONGS Units 2 and 3 costs as decommissioning costs are incurred. In December 2018, the CPUC issued a final decision finding the decommissioning cost estimates for SONGS Unit 1 generally reasonable with certain disallowances. The decision also found $136 million (in 2014 dollars) of SONGS Units 2 and 3 decommissioning expenses for 2014 and $222 million (in 2014 dollars) of SONGS Units 2 and 3 decommissioning expenses for 2015 to be reasonable.

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 incurred in 2017 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 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, 2018:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other				
U.S. government corporations and agencies(1)	$ 52	$ 1	$ —	$ 53
Municipal bonds(2)	266	4	(1)	269
Other securities(3)	238	1	(5)	234
Total debt securities	556	6	(6)	556
Equity securities	168	253	(10)	411
Cash and cash equivalents	7	—	—	7
Total	$ 731	$ 259	$ (16)	$ 974
At December 31, 2017:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other				
U.S. government corporations and agencies	$ 54	$ —	$ —	$ 54
Municipal bonds	245	7	(2)	250
Other securities	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

(1) *Maturity dates are 2019-2048.*

(2) *Maturity dates are 2019-2056.*

(3) *Maturity dates are 2019-2064.*

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 IN THE NDT
(Dollars in millions)

	Years ended December 31,		
	2018	2017	2016
Proceeds from sales	$ 890	$ 1,314	$ 1,134

Gross realized gains	42	157	111
Gross realized losses	(10)	(14)	(29)

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.

ASSET RETIREMENT OBLIGATION AND SPENT NUCLEAR FUEL

SDG&E's ARO related to decommissioning costs for the SONGS units was $626 million at December 31, 2018. 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 ARO at December 31, 2018 for all three units is based on a cost study prepared in 2017 that is pending CPUC approval. The ARO at December 31, 2018 for Units 2 and 3 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 2018 dollars is approximately $810 million.

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 in 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 results in 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.

Under the terms of the 2016 spent fuel settlement agreement, Edison filed a claim with the DOE on behalf of the SONGS co-owners in 2016 for spent fuel management costs incurred in 2014 and 2015 and a claim in 2017 for costs incurred in 2016. The DOE settled these claims with Edison in 2017 and 2018, respectively. In May 2017, SDG&E received its $9 million respective share from Edison of the settlement for 2014 and 2015 costs incurred. In July 2018, SDG&E received its $9 million share from Edison of the settlement for 2016 costs incurred. SDG&E recorded the proceeds of these settlements in balancing accounts or as reductions to regulatory assets for the benefit of ratepayers.

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. However, these changes in SONGS nuclear insurance levels require approval from all SONGS owners, as described below.

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 an additional $110 million of coverage. If a nuclear liability loss occurs at SONGS and exceeds the $450 million insurance limit, this additional coverage would be available to provide a total of $560 million in coverage limits per incident. The SFP is a program that provides additional insurance. If a nuclear liability loss occurs at any U.S. licensed/commercial reactor and exceeds the $450 million insurance limit, all SFP participants would be required to contribute to the SFP. 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. On April 5, 2018, the SONGS co-owners approved withdrawing from participation in the SFP for SONGS, but maintaining the nuclear liability insurance coverage at current levels ($450 million). Confirmation of SONGS' withdrawal from the SFP has been received and became effective January 5, 2018.

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. Effective January 10, 2018, the NRC approved Edison's request to reduce its minimum property damage insurance requirement for SONGS from $1.06 billion to $50 million. However, on April 5, 2018, the SONGS co-owners approved maintaining its current property damage insurance at $1.5 billion, but with a new $500 million property damage sublimit on the ISFSI.

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) of $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 13. 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 reasonably estimate 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, 2018, loss contingency accruals for legal matters, including associated legal fees, that are probable and estimable were $2 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.

As a result of a CPUC decision denying SDG&E's request to recover wildfire costs, 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. SDG&E continues 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. On July 12, 2018, the CPUC adopted a decision denying the rehearing requests filed by SDG&E and other parties. On August 3, 2018, SDG&E filed an appeal with the California Court of Appeal seeking to reverse the CPUC's decision. The filing also asked the court to direct the CPUC to award SDG&E recovery for payments made to settle inverse condemnation claims and limit any reasonableness review to the amounts of those payments. On November 13, 2018, the California Court of Appeal denied SDG&E's petition. On November 26, 2018, SDG&E filed an appeal with the California Supreme Court seeking to reverse the decisions of the CPUC and the California Court of Appeal. In January 2019, the California Supreme Court denied SDG&E's petition. We intend to appeal the decision up to the U.S. Supreme Court seeking to reverse the CPUC's decision.

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 2018, we had no payments under natural gas contracts.

Purchased-Power Contracts

For 2019, SDG&E expects to meet its customer power requirements from the following resource types:

- Long-term contracts: 37 percent (of which 36 percent is provided by renewable energy contracts expiring on various dates through 2041)
- Other SDG&E-owned generation and tolling contracts (including OMEC): 55 percent
- Spot market purchases: 8 percent

At December 31, 2018, the future estimated payments under long-term purchased-power contracts are as follows:

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

2019	$	527
2020		510
2021		510
2022		496
2023		451
Thereafter		5,026
Total estimated payments(1)(2)	$	7,520

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

(2) *Includes $5.2 billion of expected payments under purchase agreements accounted for as operating leases at SDG&E, comprised of 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,		
	2018	2017	2016
SDG&E	$ 712	$ 781	$ 752

Operating Leases

We have operating leases on real and personal property expiring at various dates from 2019 through 2042. 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 $201 million, $130 million of which has been utilized as of December 31, 2018.

Rent expense for operating leases was as follows:

RENT EXPENSE – OPERATING LEASES
(Dollars in millions)

	Years ended December 31,		
	2018	2017	2016

SDG&E	$ 27	$ 28	$ 28

At December 31, 2018, 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)

	2019	2020	2021	2022	2023	Thereafter	Total
Future minimum lease payments	$ 23	$ 22	$ 22	$ 21	$ 17	$ 48	$ 153
Future estimated rental payments	2	2	2	2	2	7	17
Total future rental commitments	$ 25	$ 24	$ 24	$ 23	$ 19	$ 55	$ 170

Capital Leases

Power Purchase Agreements

SDG&E has six PPAs with peaker plant facilities, one of which went into commercial operation in December 2018. All are accounted for as capital leases, four with a 25-year term, one with a 20-year term and one with a 9-year term. At December 31, 2018, the aggregate carrying value of these capital lease obligations was $1,583 million. 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, 2018, 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)

2019	$ 540
2020	210
2021	211

2022	211
2023	211
Thereafter	3,196
Total minimum lease payments(1)	4,579
Less: estimated executory costs	(480)
Less: interest(2)	(2,500)
Present value of net minimum lease payments(3)	$ 1,599

(1) This expense receives ratemaking treatment consistent with purchased-power costs, which are recovered in rates and have been recorded over the lives of the leases as Cost of Electric Fuel and Purchased Power on the Statement of Operations. See discussion in Note 2 regarding the classification of this expense after adoption of the new lease standard in 2019.

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

(3) Includes $328 million in Current Portion of Long-Term Debt and $1,255 million in Long-Term Debt on the Balance Sheet at December 31, 2018. The remaining present value of net minimum lease payments of $16 million will be recorded as finance leases when construction of the battery storage facilities is completed and delivery of contracted power commences.

The annual amortization charge for the PPAs was $52 million, $46 million and $39 million in 2018, 2017 and 2016, respectively.

Other Capital Leases

At December 31, 2018, SDG&E has capital lease obligations for fleet vehicles of $2 million, all of which are payable in 2019.

The annual depreciation charge for fleet vehicles and other assets in 2018, 2017 and 2016 was $ $2 million, $1 million and $1 million, respectively.

Construction and Development Projects

At December 31, 2018, SDG&E has commitments to make future payments of $144 million for construction projects that include:

- $135 million for infrastructure improvements for electric and natural gas transmission and distribution systems; and
- $9 million related to spent fuel management at SONGS.

SDG&E expects future payments under these contractual commitments to be $43 million in 2019, $62 million in 2020, $22 million in 2021, $11 million in 2022, $2 million in 2023 and $4 million thereafter.

OTHER COMMITMENTS

We discuss nuclear insurance and nuclear fuel disposal related to SONGS in Note 12.

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, for which a liability has been recorded, are expected to be $3 million per year in 2019 through 2023 and $105 million thereafter, subject to escalation of 2 percent per year, for a remaining 51-year period. At December 31, 2018, the present value of these future payments of $120 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.

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,		
	2018	2017	2016
SDG&E	$ 38	$ 46	$ 17

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 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, 2018 of our manufactured-gas sites and the third-party waste-disposal sites for which we have been identified as a PRP:

STATUS OF ENVIRONMENTAL SITES

	# Sites complete (1)	# 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, 2018

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	$ 3	$ 5

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

(2) Includes $1 million classified as current liabilities, and $4 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 12, does not reduce SDG&E's mitigation obligation. SDG&E's share of the estimated mitigation costs is $68 million, of which $45 million has been incurred through December 31, 2018 and $23 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 Cal PA 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. The CPUC approved the settlement agreement in March 2018. In accordance with the settlement agreement, an updated cost forecast will be submitted to the CPUC for rate recovery approval when the project's coastal development permit is approved. We expect to submit the updated cost forecast in 2019. Rates, if approved, would be effective January 2020. SDG&E's share of the reef expansion costs currently forecasted through 2023 is $4 million.

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
Cal PA	California Public Advocates Office (formerly known as CPUC Office of Ratepayer Advocates or ORA)
California Utilities	San Diego Gas & Electric Company and Southern California Gas Company, collectively
CARB	California Air Resources Board
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
Enova	Enova Corporation
EPS	earnings per common share
ERRA	Energy Resource Recovery Account
ETR	effective income tax rate
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GRC	General Rate Case
IOU	investor-owned utility
IRC	U.S. Internal Revenue Code of 1986 (as amended)
IRS	Internal Revenue Service
ISFSI	independent spent fuel storage installation
ISO	Independent System Operator
ITC	Investment tax credit
JV	joint venture
LIFO	last in first out
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)
MOU	Memorandum of Understanding
MW	megawatt
MWh	megawatt hour
NAV	net asset value
NDT	nuclear decommissioning trusts
NEIL	Nuclear Electric Insurance Limited
NOL	net operating loss

GLOSSARY (CONTINUED)

NRC	Nuclear Regulatory Commission
OCI	other comprehensive income (loss)
OII	Order Instituting Investigation
O&M	operation and maintenance expense
OMEC	Otay Mesa Energy Center
OMEC LLC	Otay Mesa Energy Center LLC
PBOP	postretirement benefits other than pension
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
ROU	right-of-use
RPS	Renewables Portfolio Standard
RSA	restricted stock award
RSU	restricted stock unit
SB	California Senate Bill
SDG&E	San Diego Gas & Electric Company
SEC	U.S. Securities and Exchange Commission
SFP	secondary financial protection
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 Owner Formula Rate, effective through December 31, 2018
TO5	Electric Transmission Owner Formula Rate, new application
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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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		(7,479,065)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(738,203)		
4	Total (lines 2 and 3)		(738,203)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(8,217,268)		
6	Balance of Account 219 at Beginning of Current Year		(8,217,268)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(1,360,811)		
9	Total (lines 7 and 8)		(1,360,811)		
10	Balance of Account 219 at End of Current Quarter/Year		(9,578,079)		

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			(7,479,065)	[redacted]	
2					
3			(738,203)		
4			(738,203)	406,693,763	405,955,560
5			(8,217,268)	[redacted]	
6			(8,217,268)		
7					
8			(1,360,811)		
9			(1,360,811)	666,868,924	665,508,113
10			(9,578,079)	[redacted]	

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)	18,486,436,139	14,713,111,189
4	Property Under Capital Leases	1,915,724,184	1,902,821,977
5	Plant Purchased or Sold	279,422	279,422
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	20,402,439,745	16,616,212,588
9	Leased to Others	85,194,000	85,194,000
10	Held for Future Use		
11	Construction Work in Progress	1,219,293,740	970,085,518
12	Acquisition Adjustments	3,750,722	3,750,722
13	Total Utility Plant (8 thru 12)	21,710,678,207	17,675,242,828
14	Accum Prov for Depr, Amort, & Depl	6,787,171,251	5,317,121,098
15	Net Utility Plant (13 less 14)	14,923,506,956	12,358,121,730
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,865,947,222	4,775,492,331
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	899,538,727	519,943,465
22	Total In Service (18 thru 21)	6,765,485,949	5,295,435,796
23	Leased to Others		
24	Depreciation	19,934,965	19,934,965
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	19,934,965	19,934,965
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	1,750,337	1,750,337
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,787,171,251	5,317,121,098

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
2,382,699,160				1,390,625,790	3
				12,902,207	4
					5
					6
					7
2,382,699,160				1,403,527,997	8
					9
					10
80,627,902				168,580,320	11
					12
2,463,327,062				1,572,108,317	13
821,458,066				648,592,087	14
1,641,868,996				923,516,230	15
					16
					17
812,652,301				277,802,590	18
					19
					20
8,805,765				370,789,497	21
821,458,066				648,592,087	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
821,458,066				648,592,087	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	(282,430,314)	312,969,686
Orange Grove	123,238,342	(12,454,767)	110,783,575
El Cajon Energy	59,751,923	(10,044,483)	49,707,440
Escondido	59,549,016	(4,620,478)	54,928,538
Fleet	12,902,207	(11,002,116)	1,900,091
Yuma	14,884,000	(716,554)	14,167,446
Pio Pico	500,000,000	(9,404,609)	490,595,391
Carlsbad	549,998,696	(136,013)	549,862,683
	1,915,724,184	(330,809,334)	1,584,914,850

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

Reclassification as of 12/2018 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	131,071,195
Steam Production Plant	232,319,974
Other Production Plant	239,196,226
Transmission Plant	1,180,379,384
Distribution Plant	3,023,537,234
General Plant	162,544,227
Ratemaking Electric	4,969,048,240
Nuclear Decommissioning	973,025,286
ASC 410 (FAS 143 and FIN 47) - Electric	(982,550,358)
Capital Leases A/D	319,807,218
Leased to Others- Citizens A/D	19,934,965
Cuyamaca Permanent Adjustment	17,855,747
Total Electric	5,317,121,098

Ratemaking Gas	1,034,589,290
FIN 47 - Gas	(213,131,224)
Total Gas	821,458,066
Ratemaking Common	634,023,744
FIN 47 - Common	3,566,227
Fleet Capital Lease A/D	11,002,116
Total Common	648,592,087
Total Accumulated Provision EOQ 12/2018	6,787,171,251
Total 13-Month Average Accum. Provision as of 12/31/2018 -Steam Production	223,700,108
Total 13-Month Average Accum. Provision as of 12/31/2018 -Nuclear Production	-
Total 13-Month Average Accum. Provision as of 12/31/2018 -Other Production	228,465,593
Total 13-Month Average Accum. Provision as of 12/31/2018 -Transmission Plant	1,120,020,421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)		

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
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	174,135,174	5,942,343
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	174,358,015	5,942,343
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	96,439,186	660,001
10	(312) Boiler Plant Equipment	172,339,530	46,666
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	138,366,212	-8,780
13	(315) Accessory Electric Equipment	85,986,719	38,772
14	(316) Misc. Power Plant Equipment	49,230,042	3,486,737
15	(317) Asset Retirement Costs for Steam Production	224,916	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	557,113,123	4,223,396
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	226,796	
38	(341) Structures and Improvements	23,043,180	531,609
39	(342) Fuel Holders, Products, and Accessories	21,995,712	
40	(343) Prime Movers	105,440,550	758,295
41	(344) Generators	360,324,290	2,183,888
42	(345) Accessory Electric Equipment	33,389,503	
43	(346) Misc. Power Plant Equipment	29,185,358	1,188,021
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	573,605,389	4,661,813
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,130,718,512	8,885,209

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	234,232,020	169,194
49	(352) Structures and Improvements	516,614,009	84,055,930
50	(353) Station Equipment	1,658,340,251	169,322,719
51	(354) Towers and Fixtures	897,312,298	4,320,779
52	(355) Poles and Fixtures	540,158,961	74,255,934
53	(356) Overhead Conductors and Devices	619,515,980	44,329,692
54	(357) Underground Conduit	360,839,809	98,642,074
55	(358) Underground Conductors and Devices	390,618,791	129,943,766
56	(359) Roads and Trails	316,139,796	4,783,368
57	(359.1) Asset Retirement Costs for Transmission Plant	1,470,639	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	5,535,242,554	609,823,456
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	103,155,365	2,335,534
61	(361) Structures and Improvements	4,650,799	4,726,811
62	(362) Station Equipment	515,733,722	40,589,615
63	(363) Storage Battery Equipment	123,925,848	429,730
64	(364) Poles, Towers, and Fixtures	713,278,356	72,568,952
65	(365) Overhead Conductors and Devices	682,221,831	81,273,338
66	(366) Underground Conduit	1,254,216,247	88,598,286
67	(367) Underground Conductors and Devices	1,541,443,312	104,073,831
68	(368) Line Transformers	657,201,300	30,795,234
69	(369) Services	511,247,886	33,740,109
70	(370) Meters	250,628,034	7,065,174
71	(371) Installations on Customer Premises	9,158,947	281,825
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	30,587,625	1,643,157
74	(374) Asset Retirement Costs for Distribution Plant	26,334,555	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,423,783,827	468,121,596
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	42,863,170	2,622,915
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	58,146	
90	(393) Stores Equipment	2,941	46,521
91	(394) Tools, Shop and Garage Equipment	32,552,616	2,210,062
92	(395) Laboratory Equipment	5,152,106	181,848
93	(396) Power Operated Equipment	60,529	
94	(397) Communication Equipment	285,610,792	34,447,153
95	(398) Miscellaneous Equipment	9,522,046	14,322,420
96	SUBTOTAL (Enter Total of lines 86 thru 95)	383,134,489	53,830,919
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)	383,134,489	53,830,919
100	TOTAL (Accounts 101 and 106)	13,647,237,397	1,146,603,523
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)	13,647,237,397	1,146,603,523

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
	296,852		180,374,369		4
	296,852		180,597,210		5
					6
					7
			14,526,518		8
7,861,341			89,237,846		9
10,633,963			161,752,233		10
					11
7,484,308	-772,160		130,100,964		12
2,172,934			83,852,557		13
239,053	-849,752	-349,147	51,278,827		14
	-115,379		109,537		15
28,391,599	-1,737,291	-349,147	530,858,482		16
					17
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			226,796		37
			23,574,789		38
			21,995,712		39
			106,198,845		40
			362,508,178		41
			33,389,503		42
		349,147	30,722,526		43
					44
		349,147	578,616,349		45
28,391,599	-1,737,291		1,109,474,831		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
	-103,300	4,941,794	239,239,708		48
892,129	-61,092		599,716,718		49
9,825,276	61,092	-276,997	1,817,621,789		50
			901,633,077		51
3,081,770	-29,437		611,303,688		52
2,352,096	29,437		661,523,013		53
			459,481,883		54
			520,562,557		55
			320,923,164		56
	21,549		1,492,188		57
16,151,271	-81,751	4,664,797	6,133,497,785		58
					59
			105,490,899		60
39,558			9,338,052		61
1,484,087		-154,298	554,684,952		62
			124,355,578		63
8,735,405	12,503	-11,534	777,112,872		64
2,204,878		11,534	761,301,825		65
2,312,423			1,340,502,110		66
10,258,657			1,635,258,486		67
6,285,856			681,710,678		68
1,751,570	375,184		543,611,609		69
287,636			257,405,572		70
11,280			9,429,492		71
					72
112,206			32,118,576		73
	1,637,448		27,972,003		74
33,483,556	2,025,135	-154,298	6,860,292,704		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			7,312,143		86
			45,486,085		87
					88
			58,146		89
2,940			46,522		90
452,204			34,310,474		91
			5,333,954		92
			60,529		93
7,692,900		431,295	312,796,340		94
			23,844,466		95
8,148,044		431,295	429,248,659		96
					97
					98
8,148,044		431,295	429,248,659		99
86,174,470	502,945	4,941,794	14,713,111,189		100
					101
					102
					103
86,174,470	502,945	4,941,794	14,713,111,189		104

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

Reclassification of 2018 Electric Plant-in-Service for Ratemaking
Plant in Service Classified under FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	BOY 2018	EOY 2018
Intangible Plant	174,135,173	180,374,368
Steam Production Plant	572,066,955	545,574,127
Nuclear Production Plant	-	-
Other Production Plant	518,147,671	522,513,934
Transmission Plant	5,463,231,690	6,051,311,848
Distribution Plant	6,494,386,287	6,940,409,503
General Plant	383,134,487	429,248,656
Ratemaking Electric	13,605,102,263	14,669,432,436
ASC 410 (FAS 143 and FIN 47)	28,030,109	29,573,728
Cuyamaca Permanent Adjustment	14,105,025	14,105,025
Total Electric Plant-in-Service	13,647,237,397	14,713,111,189

Total 13-Month Average Plant Balance for 2018 - Steam Production	545,863,137
Total 13-Month Average Plant Balance for 2018 - Nuclear Production	0
Total 13-Month Average Plant Balance for 2018 - Other Production	518,972,089
Total 13-Month Average Plant Balance for 2018 - Transmission Plant	5,678,390,068

* As a result of the SONGS plant closure, the December 2018 Nuclear Production Plant Balance is zero.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	Citizens Sunrise Transmission LLC	117 Mile-500KV Transmission Line	ER12-	07/02/2042	85,194,000
2		(Border-East Line)	686-000		
3					
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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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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:			
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21	Other Property:			
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46				
47	Total			0

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

The 13-Month Average Electric Transmission Plant Held for Future Use is $1,900,690

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	2,193,226
2	TRANSMISSION PROJECTS UNDER $500K	15,342,854
3	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	10,849,591
4	CRITICAL ASSET SECURITY	15,640,056
5	TL663 MISSION-KEARNY RECONDUCTOR	29,022,593
6	SUBSTATION SECURITY PROJECTS UNDER $500K	2,084,651
7	SYCAMORE-PENASQUITOS NEW 230KV TIE LINE	2,573,409
8	ARTESIAN 230KV SUBSTATION EXPANSION	12,682,820
9	DESERT STAR ENERGY CENTER	1,696,062
10	ORANGE COUNTY LONG RANGE PLAN	104,164,728
11	TL603B SWEETWATER TAP REMOVAL	1,550,569
12	TL674A RECONFIGURE	2,917,135
13	GRANITE SUBSTATION 69KV LOOP-IN	1,860,686
14	WARNER SUBSTATION 69KV RELAY UPGRADES	3,470,274
15	DESCANSO SUBSTATION CONTROL & PROTECTION REPLACEMENT	3,682,296
16	TL6926 RINCON-VALLEY CENTER POLE REPLACEMENT	8,329,567
17	MID-COAST TROLLEY EXTENSION PROJECT	4,345,968
18	MIGUEL TO BAY BLVD NEW 230KV LINE	6,016,049
19	VEHICLE GRID INTEGRATION	33,308,563
20	FIRE THREAT ZONE PROTECTION & SCADA UPGRADE	3,986,831
21	SEWAGE PUMP STATION REBUILDS	4,970,411
22	POINT LOMA SUSBSTATION - INSTALL 3RD BANK	18,506,300
23	EXPEDITED STORAGE PROCUREMENT	1,885,850
24	OCEAN RANCH LAND PURCHASE	21,940,507
25	SUBSTATION AUXILIARY POWER SYSTEMS	3,886,589
26	STRATEGIC FIRE HARDENING	28,688,791
27	FIRE HAZARD PREVENTION	2,552,783
28	LOS COCHES SUBSTATION REBUILD	17,991,059
29	TL649 POLE REPLACEMENT	5,496,948
30	TL6975 ESCONDIDO - SAN MARCOS	3,050,989
31	SYNCHRONIZED PHASOR MEASUREMENT SYSTEM	3,555,571
32	TL615/659 CABLE REPLACEMENT	4,633,829
33	SUBSTATION RELIABILITY UPGRADE PROJECT	13,158,585
34	IMPERIAL VALLEY SUBSTATION BANK REPLACEMENT	11,855,010
35	TL633 RECONDUCTOR	25,527,489
36	CONDITION BASED MONITORING - CIRCUIT BREAKERS	7,205,656
37	MERCHANT SWITCHYARD	15,605,217
38	TL690 WOOD TO STEEL REPLACEMENT	3,971,324
39	POWAY SUBSTATION REBUILD	3,548,746
40	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	27,552,371
41	GAS INSULATED SWITCH REPLACEMENT	2,453,985
42	TL691 WOOD TO STEEL REPLACEMENT	3,479,067
43	TOTAL	970,085,518

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	16,095,386
2	TL695 SW POLE REPLACEMENT	5,463,407
3	RANCHO SANTA FE SUBSTATION FIRE HARDENING	13,515,246
4	TL6912 WOOD TO STEEL REPLACEMENT	4,247,547
5	TL676 MISSION - MESA HEIGHTS RECONDUCTOR	25,015,074
6	TL664 SOUTHBAY-SWEETWATER UPGRADE	2,882,230
7	TEE MODERNIZATION PROGRAM	1,055,052
8	AERIAL MARKING FOR SAFETY	2,745,225
9	SOUTHWEST POWERLINK HIGH VOLTAGE CONVERSION	1,247,612
10	CLEVELAND NATIONAL FOREST POLE REPLACEMENTS	230,782,531
11	OBSOLETE SUBSTATION EQUIPMENT REPLACEMENT	5,600,162
12	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLAC. & MANHOLE REPAIR	2,705,206
13	DISTRIBUTION SUBSTATION RELIABILITY	1,414,041
14	ELECTRIC DISTRIBUTION STREET & HIGHWAY RELOCATIONS	8,492,709
15	CONVERSION FROM OH TO UG RULE 20A	13,349,425
16	SUBSTATION BREAKER AND RELAY REPLACEMENTS	4,524,155
17	UG RESIDENTIAL NEW BUSINESS	4,475,654
18	NEW BUSINESS INFRASTRUCTURE	1,373,436
19	NEW SERVICE INSTALLATIONS	2,973,459
20	OH DISTRIBUTION SERVICE MANAGEMENT	3,343,128
21	UG DISTRIBUTION SERVICE MANAGEMENT	1,020,723
22	CORRECTIVE MAINTENANCE PROGRAM	3,848,694
23	REPLACEMENT OF UNDERGROUND CABLES	2,414,940
24	WOOD POLE REINFORCEMENT	10,159,487
25	DISTRIBUTION CIRCUIT RELIABILITY CONSTRUCTION	1,112,116
26	KEARNY SUBSTATION REBUILD	36,064,459
27	SCADA CONTROL PANEL REPLACEMENT	7,528,199
28	TL698 WOOD TO STEEL REPLACEMENT	1,041,069
29	TL636 WOOD POLE REPLACEMENT	1,085,171
30	REACTIVE SMALL CAPITAL PROJECTS	1,092,896
31	STREAMVIEW SUBSTATION 69/12KV REBUILD	1,120,210
32	TL694 WOOD TO STEEL REPLACEMENT	1,161,350
33	CAPITAL RESTORATION OF SERVICE	1,365,032
34	TL667 CABLE REPLACEMENT	1,425,634
35	TL692 WOOD TO STEEL REPLACEMENT	1,524,298
36	TL686 WARNERS-NARROWS POLE REPLACEMENT	1,577,554
37	SAN MATEO SUB REBUILD	1,586,193
38	TL673 CABLE REPLACE	1,732,407
39	INFRASTRUCTURE - HARDWARE RELIABILITY	1,842,089
40	TL23001 SAN LUIS REY TO MISSION	1,927,878
41	POLE RISK MITIGATION	1,947,952
42	UG NON-RESIDENTIAL NEW BUSINESS	2,085,017
43	TOTAL	970,085,518

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	AVOCADO SUB 69KV REBUILD	2,228,793
2	TL6906 MESA RIM LOOP-IN	2,247,890
3	AB2868 ENERGY STORAGE	2,327,959
4	2ND 69KV LINE POMERADO TO POWAY	2,662,094
5	ENERGY EFFICIENCY PROGRAM	2,841,108
6	MARGARITA SUB NEW 12KV CIRCUIT	3,181,136
7	MOBILE HOME PARK UTILITY UPGRADES	3,711,814
8	WABASH CANYON SUB 69/12KV BANK 32	3,806,326
9	230KV SUBSTATION REBUILDS	4,155,646
10	C1023 NEW 12KV CIRCUIT	4,857,531
11	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	-12,959,951
12	MINOR PROJECTS (LESS THAN $1,000,000)	17,826,114
13		
14		
15	ANNUAL CHANGES IN PROJECT BALANCES ARE DUE TO COMPLETION OF	
16	OF SEPARATE SEGMENTS OF THE BUDGET.	
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43	TOTAL	970,085,518

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	4,481,327,882	4,464,229,878		17,098,004
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	465,559,255	465,559,255		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others	2,836,961			2,836,961
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)	468,396,216	465,559,255		2,836,961
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	86,174,471	86,174,471		
13	Cost of Removal	67,831,674	67,831,674		
14	Salvage (Credit)	1,203,016	1,203,016		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	152,803,129	152,803,129		
16	Other Debit or Cr. Items (Describe, details in footnote):	-55,702,388	-55,702,388		
17					
18	Book Cost or Asset Retirement Costs Retired	54,208,715	54,208,715		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,795,427,296	4,775,492,331		19,934,965
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	227,867,455	227,867,455		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	265,314,526	265,314,526		
25	Transmission	1,193,492,615	1,173,557,650		19,934,965
26	Distribution	2,946,208,472	2,946,208,472		
27	Regional Transmission and Market Operation				
28	General	162,544,228	162,544,228		
29	TOTAL (Enter Total of lines 20 thru 28)	4,795,427,296	4,775,492,331		19,934,965

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

Depreciation Provision - Electric Only (Line 10, Page 219)	$ 465,559,255
Depreciation Provision - Common Alloc. to Elec. (Line 11, pg 336)	33,682,025
Depreciation Provision - (Line 6, Col. G, Page 115)	$ 499,241,280

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

Book Cost of Plant Retired (Line 12, Col. B, Page 219)	$(86,174,471)
Total Plant Retired (Line 100, Col. D, Page 207	86,174,470
Adj. For Land & Intangible Retirements not impacting A/C 108	0
Adj. For Net Book Value of Plant Retired to Gain on Sale	0
Rounding	1
Difference:	$ 0

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

SONGS Decommissioning - Current Year Trust Income (Loss)	$(59,205,154)
Transfer of Reserve Balances between Departments	3,502,766
Other Debit and Credit Items (Line 16, Page 219)	$(55,702,388)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	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)	126,581,577	126,655,809	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	9,174,748	9,180,129	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)	367,535	367,750	ELECTRIC/GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	136,123,860	136,203,688	
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)	139,571,012	136,203,688	

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

Reclassification of FERC Form 1 2018 Materials & Supplies, Page 227, for Ratemaking
Materials and Supplies Classified
In accordance with Guidelines in FERC Order 888

	EOY 2018
Total Materials and Supplies (FERC 154)	136,203,688
As Assigned to Department for Ratemaking	
Electric Department	132,306,454
Gas Department	3,897,234
Total Allowable Materials and Supplies per FERC Formula	132,306,454
Total 13-Month Average Electric M&S for 2018	133,751,889

[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 2 FERC Filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	105,807.00			
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	-4.00			
10	Transfer to Desert Star	-4.00			
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	118,746.00		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				

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.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						105,807.00		1
								2
								3
12,947.00		12,947.00		349,569.00		401,357.00		4
								5
								6
								7
								8
						-4.00		9
						-4.00		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		507,156.00		29
								30
								31
								32
								33
								34
								35
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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						
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12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21	Sycamore-Bernardo Project	1,366,481				1,366,481
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	1,366,481				1,366,481

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					
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11					
12					
13					
14					
15					
16					
17					
18					
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20					
21	**Generation Studies**				
22					
23					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Taxes Recoverable in Rates	732,473,240	35,594,061	Various	1,486,107	766,581,194
2	Amortized Over Various Lives					
3						
4	Employer's Accounting for Postemployment Benefits	3,427,000	1,931,000			5,358,000
5						
6	Environmental Clean-Up	4,551,457	2,466,910	242 / 253	1,987,027	5,031,340
7						
8	Balancing Account Undercollections	505,805,987	3,850,817			509,656,804
9						
10	Pension Benefits	162,868,076	25,016,899			187,884,975
11						
12	SONGS Mitigation	24,016,994		242 / 253	1,418,073	22,598,921
13						
14	Electric Derivatives	225,418,857		Various	88,805,382	136,613,475
15						
16	Contribution to City of Escondido	1,341,505		253	138,587	1,202,918
17	(20 year life, starting 2006)					
18						
19	Asset Retirement Obligations	16,262,430	3,222,813	Various	965,924	18,519,319
20						
21	Sunrise Wildfire Mitigation	118,930,093	890,013			119,820,106
22						
23	Beyond The Meter	18,583,948	4,161,828	232	2,334,790	20,410,986
24						
25	Unamortized Line of Credit (LOC) Net	1,062,835		930	375,150	687,685
26						
27	Theoretical Withdrawal Premium OIL		15,997,255			15,997,255
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,814,742,422	93,131,596		97,511,040	1,810,362,978

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	381,312	685,208	431	433,916	632,604
2						
3	Southwest Powerlink Deferred	332,266		406	15,744	316,522
4	per CPUC					
5	(amortization 1/1986 - 12/2023)					
6						
7	Mitigation Fund	137,706				137,706
8						
9	Environmental Program	6,196,955		various	255,685	5,941,270
10						
11	Workers Comp Receivable	7,811,728	1,308,567	various	123,277	8,997,018
12						
13	SONGS Decommissioning	2,296,367	29,705,383	228	31,687,922	313,828
14						
15	Pendleton Energy Park	195,734				195,734
16						
17	Gaskell Tax Equity	115,312				115,312
18						
19	Supervisory Control & Data	498,664				498,664
20	Acquisition Equipment					
21						
22	SONGS Reg Asset Receivable	119,974,302		143	35,920,005	84,054,297
23						
24	PBOP Asset	10,065,432	4,384,576	254	12,159,677	2,290,331
25						
26	Surplus Material	1,978,396	2,742,279			4,720,675
27						
28	Airbus Helicopter Trade Account		462,000			462,000
29						
30	Miscellaneous Other	143,644	37,217	various	19,477	161,384
31						
32						
33						
34						
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42						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	150,127,818				108,837,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	65,586,640	73,102,522
3	State	63,253,360	66,258,760
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	128,840,000	139,361,282
9	Gas		
10	Federal	4,641,292	5,163,527
11	State	2,352,225	2,326,155
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	6,993,517	7,489,682
17	Other (Specify) Non-Utiltity	57,781,336	409,639
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	193,614,853	147,260,603

Notes

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

Account 190 electric balance at the beginning of the year reflects amortization of transmission related excess deferred federal income taxes in the amount of $0.

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

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

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

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

Account 190 electric balance at the end of the year reflects amortization of transmission related excess deferred federal income taxes in the amount of $1,232,000.

Account 190 non-Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($233,360,930).

Account 190 Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($12,026,401).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($2,141,800).

The deferred tax asset related to FERC transmission on a stand-alone basis as of December 31, 2018 and 2017 is reflected in the table below:

STAND-ALONE FERC TRANSMISSION NET OPERATING LOSS DEFERRED TAX ASSET (1)
(Dollars in millions)

	Years ended December 31,			
		2018		2017
FERC AC 190				
FERC - Remeasured Amount	$	124	$	162
FERC - Excess Reserve Protected	$	109	$	108
FERC - Excess Reserve Unprotected	$	0	$	0
Total	$	233	$	270

(1) Does not include any amounts related to Citizens.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common	255,000,000	2.50	
2				
3	Preferred Stock	45,000,000		
4				
5				
6				
7	Note: All the Common Stock of San Diego Gas &			
8	Electric is owned by Enova Corporation and is			
9	not publicly traded.			
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
116,583,358	291,458,395					1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 208 - None	
2		
3	ACCOUNT 209 - None	
4		
5	ACCOUNT 210 - None	
6		
7	ACCOUNT 211	
8	Asset Transferred from Sempra Energy	79,665,368
9	Equity infusion from Enova Corporation	400,000,000
10	Total Account 211	479,665,368
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40	TOTAL	479,665,368

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		
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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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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		
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	4,901,265,000	71,352,632

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	1.914% Series PPP due 2022	250,000,000	1,715,986
7			
8	2.500% Series QQQ due 2026	500,000,000	4,279,086
9			1,625,000 D
10	3.750% Series RRR due 2047	400,000,000	4,038,478
11			1,784,000 D
12	4.150% Series SSS due 2048	400,000,000	4,069,998
13			1,768,000 D
14			
15			
16	TOTAL ACCOUNT 221	4,901,265,000	71,352,632
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29			
30			
31			
32			
33	TOTAL	4,901,265,000	71,352,632

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		1,319,957	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
				4,776,266,000	200,012,289	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
03/12/15	02/01/22	03/12/15	02/01/22	125,001,000	2,620,375	6
						7
05/19/16	05/15/26	05/19/16	05/15/26	500,000,000	12,500,000	8
						9
06/08/17	06/01/47	06/08/17	06/01/47	400,000,000	15,000,000	10
						11
05/15/18	05/15/48	05/17/18	05/15/48	400,000,000	10,328,889	12
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				4,776,266,000	200,012,289	16
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				4,776,266,000	200,012,289	33

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

Expense	$53,238,132
Discount	$18,114,500
Account 221	$71,352,632

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 May 2018, SDG&E issued 4.1500% First Mortgage bond series SSS for $400,000,000 due 2048. At December 2018 total remaining authority for new debt was $66,630,000 and rollover debt was $121,930,000.

D.18-02-012 - In February 2018, SDG&E received authority from the California Public Utilities Commission to issue $750,000,000 of new debt under Decision 15-08-011 and $300,000,000 in rollover debt. SDG&E has not issued any debt under this decision.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	666,868,924
2		
3		
4	Taxable Income Not Reported on Books	
5	Regulatory Balancing Accounts	140,879,036
6	Contributions in Aid of Construction	27,205,760
7	Other (Itemized within footnote)	6,200
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	657,540,182
11	Federal and State Taxes	173,274,598
12	Amortization and Interest Capitalized	69,937,426
13	Other (Itemized within footnote)	24,873,367
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	-80,290,516
16	Deferred Construction Revenue	-6,725,935
17	SONGS Decommissioning Costs	-2,905,826
18	Keyman Life Insurance	-6,000,301
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-456,325,385
21	Percentage Repair Allowance	-169,957,528
22	Current State Tax Deduction	-63,414,175
23	Software Development Costs	-85,693,825
24	Removal Costs	-78,384,233
25	Abandonment Loss	-248,394,498
26	Other (Itemized within footnote)	-40,226,442
27	Federal Tax Net Income	521,042,540
28	Show Computation of Tax:	
29	Federal Tax @ 21%	109,418,933
30	Deferred Taxes	22,210,824
31	Tax Credits and Other Adjustments (net)	-11,895,813
32	Fed Discrete Taxes	-1,028,354
33	Total Federal Income Tax Expense	118,705,590
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44		

Schedule Page: 261 Line No.: 7 Column: b

Fuel Tax Credit Addback	$ 6,200
	$ 6,200

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

Fringe Benefits	$ 1,753,065
Meals & Entertainment	2,016,012
Bad Debt	1,893,402
Miscellaneous Expenses	3,937,009
Book Loss on Sale of Utility Property	1,173,507
Restricted Stock	12,345,372
Contingency Book Reserves	1,755,000
	$ 24,873,367

Schedule Page: 261 Line No.: 17 Column: b

South Georgia Adjustment of $1,347,000 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

SERP	$(3,997,594)
Stock Options	(1,404,024)
Deferred Debits/Credits	(9,943,205)
Miscellaneous Expenses	(502,567)
Property Tax / Ad Valorem	(7,268,667)
Facts & Circumstances Repairs	(17,110,385)
	$(40,226,442)

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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)	BALANCE AT BEGINNING OF YEAR 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)		827,576	128,200,010	143,643,915	-14,845,905
3	Sales and Use (Note 2)	33,041		524,432	542,766	
4	Business License			47,664	47,664	
5						
6	SUBTOTAL	33,041	827,576	128,772,106	144,234,345	-14,845,905
7						
8	STATE:					
9	Franchise (Note 3)		587,588	29,881,438	20,288,125	939,335
10	Unemployment (Note 4)	513,773		883,361	867,130	
11	Sales and Use (Note 2)	85,830		1,798,049	1,860,913	
12	Fuel Tax	5,420		-10,032	-13,554	
13						
14	SUBTOTAL	605,023	587,588	32,552,816	23,002,614	939,335
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)	6,892,180		104,626,148	91,364,324	431,260
18	Retirement (Note 4)	1,041,556		27,827,225	27,733,337	
19	Unemployment (Note 4)	777,452		-667,062	4,426	
20	Medicare (Note 4)	243,570		8,027,154	8,005,178	
21	Fuel Tax		99,746	16,604	14,632	
22						
23						
24	SUBTOTAL	8,954,758	99,746	139,830,069	127,121,897	431,260
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	9,592,822	1,514,910	301,154,991	294,358,856	-13,475,310

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (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
	1,425,576	111,920,851			16,279,159	2
14,707					524,432	3
		43,153			4,511	4
						5
14,707	1,425,576	111,964,004			16,808,102	6
						7
						8
8,066,390		27,732,020			2,149,418	9
530,004		649,768			233,593	10
22,966					1,798,049	11
8,942					-10,032	12
						13
8,628,302		28,381,788			4,171,028	14
						15
						16
19,722,744		93,320,720			11,305,428	17
1,135,444		10,308,174			17,519,051	18
105,964		-490,667			-176,395	19
265,546		2,972,546			5,054,608	20
	97,774				16,604	21
						22
						23
21,229,698	97,774	106,110,773			33,719,296	24
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29,872,707	1,523,350	246,456,565			54,698,426	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 $795,652.

Property Tax expense of $631,559 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 $631,559. 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	939,335	(939,335)			
Total - California Corporation Franchise Tax Adjustment	939,335	(939,335)	-	-	-

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	-	-			
Balance Sheet Reclassification Due to FIN 48 Liab	431,260		(431,260)		
Balance Sheet Reclassification Due to FIN 48 Liab - Interest	-			-	-
Total - Federal Income Tax Adjustment	431,260	-	(431,260)	-	-

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

Payroll Tax expense of $24,297 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 $24,297 associated with the Citizens portion of Border-Eastline.

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.

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Varous	15,652,620			411.4	1,504,003	
7							
8	TOTAL	15,652,620				1,504,003	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility Various	1,987,430			411.4	512,929	
11							
12							
13							
14							
15							
16							
17							
18							
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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
14,148,617	25 to 30 years		6
			7
14,148,617			8
			9
1,474,501	25 to 30 Years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits	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	66,513,414	456/495	11,880,141	7,442,827	62,076,100
2	Amortized over various 31 yr lives					
3						
4	SONGS Mitigation	21,643,732	182.3	2,978,113	96,000	18,761,619
5						
6	OII Insurance Limited	7,494,509			8,502,745	15,997,254
7						
8	Sunrise Fire Mitigation Liability	115,494,965	182.3	3,503,829	4,325,141	116,316,277
9						
10	Citizens Lease	66,864,748	242	2,836,961		64,027,787
11						
12	Greenhouse Gas Obligations		158	62,597,932	92,799,642	30,201,710
13						
14	Miscellaneous	16,291,016	Various	8,111,781	5,702,604	13,881,839
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	294,302,384		91,908,757	118,868,959	321,262,586

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

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

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							21

NOTES (Continued)

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	1,381,478,005	115,667,215	70,156,068
3	Gas	146,468,566	12,080,224	13,358,747
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,527,946,571	127,747,439	83,514,815
6				
7	Non Utility	60,568,385		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,588,514,956	127,747,439	83,514,815
10	Classification of TOTAL			
11	Federal Income Tax	1,334,250,000	79,447,362	70,492,476
12	State Income Tax	254,264,956	48,300,077	13,022,339
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (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
				Various	37,908,707	1,464,897,859	2
				Various	6,059,666	151,249,709	3
							4
					43,968,373	1,616,147,568	5
							6
55,871,764	23,042,886	254	84,553,302	182.3	26,163,730	35,007,691	7
							8
55,871,764	23,042,886		84,553,302		70,132,103	1,651,155,259	9
							10
54,019,255	23,042,886		84,553,302		69,938,077	1,359,566,030	11
1,852,509					194,026	291,589,229	12
							13

NOTES (Continued)

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

Account 282 electric balance at the beginning 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 beginning of the year was $639,177,602.

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

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

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

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

Account 282 electric balance at the end of the year reflects a reduction for (amortization) of non-Citizens transmission related excess deferred federal income taxes in the amount of ($3,655,000).

Account 282 electric balance at the end of the year reflects a reduction for (amortization) of Citizens transmission related excess deferred federal income taxes in the amount of ($180,000).

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $661,424,763.

Account 282 Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $12,846,240.

Account 282 non-Citizen transmission related excess deferred income tax reserve at the end of the year was $385,497,611.

Account 282 Citizen transmission related excess deferred income tax reserve at the end of the year was $8,679,665.

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		52,884,395	55,456,870	82,093,623
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	52,884,395	55,456,870	82,093,623
10	Gas			
11		21,000,169	5,788,898	9,855,705
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	21,000,169	5,788,898	9,855,705
18	Non-Utilities	29,051,755		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	102,936,319	61,245,768	91,949,328
20	Classification of TOTAL			
21	Federal Income Tax	5,327,917	44,935,627	65,741,029
22	State Income Tax	97,608,402	16,310,141	26,208,299
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					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		Various	4,741,590	Various	33,303,070	54,809,122	3
							4
							5
							6
							7
							8
			4,741,590		33,303,070	54,809,122	9
							10
		Various	15,886,985	Various	408,071	1,454,448	11
							12
							13
							14
							15
							16
			15,886,985		408,071	1,454,448	17
45,470	730,911	Various	10,479,463	Various	6,681,875	24,568,726	18
45,470	730,911		31,108,038		40,393,016	80,832,296	19
							20
45,470	514,381				72,129,339	56,182,943	21
	216,530		31,108,038		-31,736,323	24,649,353	22
							23

NOTES (Continued)

Schedule Page: 276   Line No.: 3   Column: b

Account 283 electric balance at the beginning of the year reflects a reduction for amortization of transmission related excess deferred federal income taxes in the amount of $0

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the beginning of the year was $6,398,000.

Schedule Page: 276   Line No.: 3   Column: k

Account 283 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 ($2,559,000).

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the end of the year was $5,328,000.

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	1,013,014,286	Various	1,003,671,895	992,741,589	1,002,083,980
3						
4						
5	Asset Retirement Obligations	553,550,129	Various	91,145,509	6,329,787	468,734,407
6						
7						
8	Balancing Account Overcollections	287,180,993			254,118,394	541,299,387
9						
10						
11	Electric / Gas Derivatives	129,225,826	Various	480,083	158,201,501	286,947,244
12						
13						
14	PBOP Benefits	10,065,432	Various	7,775,101		2,290,331
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,993,036,666		1,103,072,588	1,411,391,271	2,301,355,349

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	1,603,852,935	1,452,724,928
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,519,500,355	1,433,017,503
5	Large (or Ind.) (See Instr. 4)	402,970,619	380,874,065
6	(444) Public Street and Highway Lighting	14,942,475	15,116,968
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,541,266,384	3,281,733,464
11	(447) Sales for Resale	562,100,549	508,344,524
12	TOTAL Sales of Electricity	4,103,366,933	3,790,077,988
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,103,366,933	3,790,077,988
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	100,348,353	94,298,549
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,791,140	4,682,000
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	98,905,972	-1,227,390
22	(456.1) Revenues from Transmission of Electricity of Others	256,061,609	201,104,161
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	461,107,074	298,857,320
27	TOTAL Electric Operating Revenues	4,564,474,007	4,088,935,308

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	No.
				1
6,336,436	6,577,628	1,290,690	1,280,264	2
				3
6,539,118	6,762,806	151,082	151,272	4
2,182,924	2,203,979	435	444	5
80,533	78,670	2,059	2,044	6
				7
				8
				9
15,139,011	15,623,083	1,444,266	1,434,024	10
11,199,395	13,677,887			11
26,338,406	29,300,970	1,444,266	1,434,024	12
				13
26,338,406	29,300,970	1,444,266	1,434,024	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	$ 92,752,428
Service Establishment	3,116,050
Net Energy Metering	2,452,060
Late Payment Charge	721,327
Mover Service Charge	648,933
Other*	657,555
	$100,348,353

* Individual balances are less than $250,000

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

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.: 19 Column: b

Includes Transmission Revenue Credits of $1,163,016

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

Includes Transmission Revenue Credits of $1,157,417

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

Description

Direct Access	$257,483,114
Balancing Accounts	(287,840,406)
Cap and Trade Revenues	101,064,845
Payment Participation	611,145
CIAC Income Tax	5,770,444
Shared Assets	3,269,553
PUC Reimbursement Fee	8,601,335
Government Turnkey	(2,767,917)
Unbilled Revenue	468,000
Joint Pole Activity	3,106,121
Generation Trans. Interconnection Rev.	2,286,377
Affiliation Empl Transfer Fees	1,161,825
Other*	5,691,536
	$ 98,905,972

* Individual balances are less than $250,000
* Includes Transmission Revenue Credits of $3,057,821

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

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

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					
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	4,344,320	1,212,820,724	904,314	4,804	0.2792
2	DRTOU	577,787	150,238,002	115,223	5,015	0.2600
3	EVTOU	128,632	29,582,261	12,542	10,256	0.2300
4	DRLI	1,091,004	172,166,552	252,602	4,319	0.1578
5	DM	40,314	10,765,551	3,485	11,568	0.2670
6	DS	17,005	3,187,849	232	73,297	0.1875
7	DT	135,557	24,429,282	409	331,435	0.1802
8	OL-1	1,589	527,577	1,840	864	0.3320
9	DWL	228	135,137	43	5,302	0.5927
10	Total Residential Sales (440)	6,336,436	1,603,852,935	1,290,690	4,909	0.2531
11						
12	A	53,709	9,761,746	6,877	7,810	0.1818
13	ASTOD	1,998,703	506,024,770	121,063	16,510	0.2532
14	ATOU	71,309	16,084,364	978	72,913	0.2256
15	AD	11,869	3,203,246	75	158,253	0.2699
16	UM	7,260	1,835,014	106	68,491	0.2528
17	PA	207	33,188	1	207,000	0.1603
18	PAT1	301,502	52,274,620	3,883	77,647	0.1734
19	AL-TOU	3,999,330	906,219,546	15,512	257,822	0.2266
20	SPSS		-39,610	5		
21	DGAL	42,609	11,121,013	252	169,083	0.2610
22	AY-TOU	32,922	8,003,153	138	238,565	0.2431
23	OL-1	5,082	15,522,752	1,680	3,025	3.0545
24	OLTOU	2,856	673,122	38	75,158	0.2357
25	TOUA	11,760	2,783,431	474	24,810	0.2367
26	Total Commercial (444)	6,539,118	1,533,500,355	151,082	43,282	0.2345
27						
28	AL-TOU	2,134,889	392,157,627	421	5,070,995	0.1837
29	DG		452,477			
30	A6-TOU	48,035	10,360,515	14	3,431,071	0.2157
31	Total Industrial (442)	2,182,924	402,970,619	435	5,018,216	0.1846
32						
33	LS1	16,177	5,615,620	783	20,660	0.3471
34	LS2	62,982	9,111,079	1,125	55,984	0.1447
35	LS3	1,374	214,480	151	9,099	0.1561
36	Total Public Street and Highway (	80,533	14,941,179	2,059	39,113	0.1855
37						
38						
39						
40						
41	TOTAL Billed	15,139,011	3,541,266,384	1,444,266	10,482	0.2339
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	15,139,011	3,541,266,384	1,444,266	10,482	0.2339

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	California ISO					
2	City of Escondido (Rincon Hydro Plant)	SF	FERC Vol. 10			
3	City of Burbank	SF	FERC Vol. 10			
4	Exelon Generation Company LLC	SF	FERC Vol. 10			
5	Los Angeles Dept. of Water & Power	SF	FERC Vol. 10			
6	Morgan Stanley Capital Group	SF	FERC Vol. 10			
7	Peninsula Clean Energy Authority	SF	FERC Vol. 10			
8	Shell Energy North America (US) LP	SF	FERC Vol. 10			
9	Southern California Edison	SF	FERC Vol. 10			
10	TransAlta Energy Marketing US	SF	FERC Vol. 10			
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
10,900,264		548,275,634		548,275,634	1
139		21,780		21,780	2
4,800		101,600		101,600	3
3,600		182,800		182,800	4
3,180		502,598		502,598	5
147,212		5,283,557		5,283,557	6
130,000		5,358,780	2,015,000	7,373,780	7
800		50,000		50,000	8
3,400		101,800		101,800	9
6,000		207,000		207,000	10
					11
					12
					13
					14
0	0	0	0	0	
11,199,395	0	560,085,549	2,015,000	562,100,549	
11,199,395	**0**	**560,085,549**	**2,015,000**	**562,100,549**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) X An Original (2) __ A Resubmission	04/16/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 7 Column: j

Contract to sell Renewable Energy Credit

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,323,823	1,908,837
5	(501) Fuel	125,486,426	108,006,886
6	(502) Steam Expenses	10,030	
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	176,593	269,830
10	(506) Miscellaneous Steam Power Expenses	6,642,826	7,061,559
11	(507) Rents	30,174	34,319
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	134,669,872	117,281,431
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		235
16	(511) Maintenance of Structures	139,871	187,301
17	(512) Maintenance of Boiler Plant	1,742,687	2,465,563
18	(513) Maintenance of Electric Plant	748,592	221,622
19	(514) Maintenance of Miscellaneous Steam Plant	6,684,017	6,102,871
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,315,167	8,977,592
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	143,985,039	126,259,023
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	2,206,176	1,491,648
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	2,206,176	1,491,648
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	139,672	150,872
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	370	
38	(531) Maintenance of Electric Plant		19
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	140,042	150,891
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	2,346,218	1,642,539
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	265,816	373,110
63	(547) Fuel	4,523,782	4,596,702
64	(548) Generation Expenses	592	6,074
65	(549) Miscellaneous Other Power Generation Expenses	4,318,733	6,519,964
66	(550) Rents	2,905	
67	TOTAL Operation (Enter Total of lines 62 thru 66)	9,111,828	11,495,850
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	15,385	-27,884
71	(553) Maintenance of Generating and Electric Plant	7,950,901	8,239,411
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	6,469,197	5,115,961
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	14,435,483	13,327,488
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	23,547,311	24,823,338
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,868,120,739	1,757,208,368
77	(556) System Control and Load Dispatching	2,899,082	2,812,365
78	(557) Other Expenses	6,336,067	6,394,783
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,877,355,888	1,766,415,516
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,047,234,456	1,919,140,416
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,649,066	7,370,790
84			
85	(561.1) Load Dispatch-Reliability	543,587	573,843
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,623,613	1,488,163
87	(561.3) Load Dispatch-Transmission Service and Scheduling	228,218	208,289
88	(561.4) Scheduling, System Control and Dispatch Services	5,880,423	6,098,268
89	(561.5) Reliability, Planning and Standards Development	161,160	156,512
90	(561.6) Transmission Service Studies		28
91	(561.7) Generation Interconnection Studies	2,091	1,855
92	(561.8) Reliability, Planning and Standards Development Services	3,340,035	3,305,693
93	(562) Station Expenses	8,343,000	7,321,035
94	(563) Overhead Lines Expenses	4,406,208	4,984,136
95	(564) Underground Lines Expenses		3,115
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	18,341,678	19,437,114
98	(567) Rents	2,890,113	2,436,591
99	TOTAL Operation (Enter Total of lines 83 thru 98)	52,409,192	53,385,432
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,329,345	1,056,954
102	(569) Maintenance of Structures	9,935	1,181
103	(569.1) Maintenance of Computer Hardware	1,322,203	1,410,754
104	(569.2) Maintenance of Computer Software	1,941,603	2,052,929
105	(569.3) Maintenance of Communication Equipment		37
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	165,388	130,165
107	(570) Maintenance of Station Equipment	14,934,723	12,091,903
108	(571) Maintenance of Overhead Lines	14,791,551	16,365,161
109	(572) Maintenance of Underground Lines	671,305	597,842
110	(573) Maintenance of Miscellaneous Transmission Plant		3,150
111	TOTAL Maintenance (Total of lines 101 thru 110)	36,166,053	33,710,076
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	88,575,245	87,095,508

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	3,492,532	3,406,759
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,492,532	3,406,759
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)	3,492,532	3,406,759
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	16,777,141	15,909,212
135	(581) Load Dispatching	2,476,936	2,385,779
136	(582) Station Expenses	2,734,546	3,434,871
137	(583) Overhead Line Expenses	6,223,324	5,666,945
138	(584) Underground Line Expenses	4,842,071	4,201,316
139	(585) Street Lighting and Signal System Expenses	659,704	669,949
140	(586) Meter Expenses	9,363,084	9,457,830
141	(587) Customer Installations Expenses	5,398,576	5,599,731
142	(588) Miscellaneous Expenses	24,830,171	36,641,612
143	(589) Rents	268,020	387,609
144	TOTAL Operation (Enter Total of lines 134 thru 143)	73,573,573	84,354,854
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,470,831	1,658,570
147	(591) Maintenance of Structures	397	102
148	(592) Maintenance of Station Equipment	2,334,479	2,099,774
149	(593) Maintenance of Overhead Lines	49,790,819	44,974,258
150	(594) Maintenance of Underground Lines	8,557,899	8,944,324
151	(595) Maintenance of Line Transformers	2,550	5,498
152	(596) Maintenance of Street Lighting and Signal Systems	20,400	73,996
153	(597) Maintenance of Meters	1,453,825	1,556,884
154	(598) Maintenance of Miscellaneous Distribution Plant	1,528,151	707,782
155	TOTAL Maintenance (Total of lines 146 thru 154)	65,159,351	60,021,188
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	138,732,924	144,376,042
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	62	84
160	(902) Meter Reading Expenses	1,527,379	1,968,301
161	(903) Customer Records and Collection Expenses	47,308,005	38,531,346
162	(904) Uncollectible Accounts	6,486,856	5,016,696
163	(905) Miscellaneous Customer Accounts Expenses	-252,771	852,571
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,069,531	46,368,998

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
168	(908) Customer Assistance Expenses	141,594,006	170,555,193
169	(909) Informational and Instructional Expenses	60,414	157,711
170	(910) Miscellaneous Customer Service and Informational Expenses	2,995,531	3,866,023
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	144,649,951	174,579,502
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	38,528,063	36,248,332
182	(921) Office Supplies and Expenses	8,714,184	7,641,102
183	(Less) (922) Administrative Expenses Transferred-Credit	10,239,581	7,634,719
184	(923) Outside Services Employed	93,646,322	83,058,369
185	(924) Property Insurance	5,523,006	5,391,972
186	(925) Injuries and Damages	112,646,052	95,755,200
187	(926) Employee Pensions and Benefits	48,997,417	40,059,178
188	(927) Franchise Requirements	131,978,202	120,400,695
189	(928) Regulatory Commission Expenses	20,960,246	18,404,990
190	(929) (Less) Duplicate Charges-Cr.	1,622,265	2,220,724
191	(930.1) General Advertising Expenses	242,684	192,754
192	(930.2) Miscellaneous General Expenses	7,563,737	7,233,074
193	(931) Rents	11,844,364	11,960,795
194	TOTAL Operation (Enter Total of lines 181 thru 193)	468,782,431	416,491,018
195	Maintenance		
196	(935) Maintenance of General Plant	9,056,059	9,138,210
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	477,838,490	425,629,228
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,955,593,129	2,800,596,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Calpeak Power LLC	OS				
7	Campo Verde Solar LLC	LU	FERC Vol. 10			
8	Carlsbad Energy Center LLC	LU	FERC Vol. 10			
9	Cascade Solar LLC	LU	FERC Vol. 10			
10	Catalina Solar LLC	LU	FERC Vol. 10			
11	Centinela Solar Energy LLC	LU	FERC Vol. 10			
12	Centinela Solar Energy 2 LLC	LU	FERC Vol. 10			
13	City of Escondido (Bear Valley Hydro)	LU	FERC Vol. 10			
14	City of Oceanside (San Francisco Peak)	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.
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	Clean Power Alliance	LU	FERC Vol. 10			
2	Coram Energy LLC	LU	FERC Vol. 10			
3	CP Kelco US Inc	LU	FERC Vol. 10			
4	CSolar IV South LLC	LU	FERC Vol. 10			
5	CSolar IV West LLC	LU	FERC Vol. 10			
6	Desert Green Solar Farm LLC	LU	FERC Vol. 10			
7	Dynergy Power Marketing Inc	AD	FERC Vol. 10			
8	El Cajon Energy Center (Tolling)	LU	FERC Vol. 10			
9	Energia Sierra Juarez US LLC	LU	FERC Vol. 10			
10	Escondido Energy Center LLC	LU	FERC Vol. 10			
11	FPL Energy Green Power Wind LLC	LU	FERC Vol. 10			
12	Goal Line LP	LU	FERC Vol. 10			
13	Grossmont Hospital Corporation	LU	FERC Vol. 10			
14	HL Power Company LP	LU	FERC Vol. 10			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	Average Monthly CP Demand (f)
1	Imperial Valley Solar I LLC	LU	FERC Vol. 10			
2	Kumeyaay Wind LLC	LU	FERC Vol. 10			
3	Manzana Wind LLC		FERC Vol. 10			
4	Maricopa West Solar PV LLC	LU	FERC Vol. 10			
5	Midway Solar Farm III					
6	MM Prima Deshecha Energy LLC	LU	FERC Vol. 10			
7	MM San Diego LLC (Miramar RAM)	LU	FERC Vol. 10			
8	Morgan Stanley Capital Group	LU	FERC Vol. 10			
9	Naturener Glacier Wind Energy 1 LLC	EX				
10	Naturener Glacier Wind Energy 2 LLC	EX				
11	Naturener Rim Rock Wind Energy LLC	EX				
12	NLP Valley Center Solar LLC	LU	FERC Vol. 10			
13	NLP Granger A82 LLC	LU	FERC Vol. 10			
14	NRG Solar Borrego 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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Oak Creek Wind Power LLC	LU	FERC Vol. 10			
2	Oasis Power Partners LLC	LU	FERC Vol. 10			
3	Ocotillo Express LLC	LU	FERC Vol. 10			
4	Olivenhain Muni Water District	LU	FERC Vol. 10			
5	Orange Grove Energy Center (Tolling)	LU	FERC Vol. 10			
6	Otay Landfill Gas I	LU	FERC Vol. 10			
7	Otay Landfill Gas II	LU	FERC Vol. 10			
8	Otay Landfill Gas V	LU	FERC Vol. 10			
9	Otay Landfill Gas VI	LU	FERC Vol. 10			
10	Otay Mesa Energy Center (Tolling)	LU	FERC Vol. 10			
11	Pacific Wind Lessee LLC	LU	FERC Vol. 10			
12	Pio Pico Energy Center	LU	FERC Vol. 10			
13	San Diego County Water Authority (Hod)	LU	FERC Vol. 10			
14	San Gorgonio Westwinds II 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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	San Marcos Energy LLC	LU	FERC Vol. 10			
2	SG2 imperial Valley LLC	LU	FERC Vol. 10			
3	Sol Orchard 20 LLC (Ramona 1)	LU	FERC Vol. 10			
4	Sol Orchard 21 LLC (Ramona 2)	LU	FERC Vol. 10			
5	Sol Orchard 22 LLC (Valley Center 1)	LU	FERC Vol. 10			
6	Sol Orchard 23 LLC (Valley Center 2)	LU	FERC Vol. 10			
7	Sycamore Energy 1 LLC	LU	FERC Vol. 10			
8	Sycamore Energy 2 LLC	LU	FERC Vol. 10			
9	Tallbear Seville LLC	LU	FERC Vol. 10			
10	Yuma Co-generator Association	LU	FERC Vol. 10			
11	BP Energy Company	SF	FERC Vol. 10			
12	Exelon Generation Company LLC	SF	FERC Vol. 10			
13	Intergen Energy Solutions LLC					
14	SAAVI Energy Solutions					
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Sacramento Municipal Utility District					
2	Sempra Gas & Power Marketing LLC					
3	Shell Energy North America (US) LP	SF	FERC Vol. 10			
4	TreansAlta Energy Marketing US	SF	FERC Vol. 10			
5	Accion Group Inc					
6	Broker Fees	OS				
7	Hedging Activity	OS				
8	ONDA Energy	OS				
9	GHG Allowances	OS				
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)	
367,611			347,611	40,391,541	3,812,047	44,551,199	1
94,408			1,115,882	3,341,763		4,457,645	2
58,024			41,109	2,918,769		2,959,878	3
16,667,167				891,292,023	-45,728,893	845,563,130	4
47,803			-24,500	3,247,535	391,381	3,614,416	5
			2,840,832			2,840,832	6
358,090			-2,012	39,158,499	3,203,249	42,359,736	7
7,113			4,123,100	8,348,961	-25,373,801	-12,901,740	8
55,032				4,341,114	-5,020	4,336,094	9
265,818			-1,749	34,826,292	-28,184	34,796,359	10
374,341				47,272,087	4,708,654	51,980,741	11
133,547				16,498,798	1,460,463	17,959,261	12
133			1,254	6,814		8,068	13
296			2,916	12,810		15,726	14
24,147,129	1,144,710	1,144,710	214,804,884	1,645,244,420	8,071,435	1,868,120,739	

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.
			-82,500			-82,500	1
26,477				2,642,977	-2,648	2,640,329	2
8,800			41,295	316,640		357,935	3
303,182			-1,701	38,593,326	3,687,274	42,278,899	4
411,446			-2,194	42,227,502	3,037,932	45,263,240	5
13,486			-1	1,880,844	-1,347	1,879,496	6
					-8	-8	7
16,880			6,619,546	2,026,938		8,646,484	8
442,572			-3,672	49,202,168	-44,257	49,154,239	9
25,261			7,599,127	1,874,366		9,473,493	10
16,896				1,100,023		1,100,023	11
19,030			11,256,500	925,958		12,182,458	12
3,108			16,947	136,526		153,473	13
182,202				19,885,652		19,885,652	14
24,147,129	1,144,710	1,144,710	214,804,884	1,645,244,420	8,071,435	1,868,120,739	

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)	
541,069			-41	59,289,518	5,185,528	64,475,005	1
157,097			226,703	8,063,416	103,569	8,393,688	2
274,610				15,854,873	375,076	16,229,949	3
49,449			-20	3,416,493	-4,959	3,411,514	4
16,496				791,679	-1,650	790,029	5
44,436				2,704,661		2,704,661	6
30,628				2,626,046		2,626,046	7
532,109				36,013,835		36,013,835	8
	262,685	262,685		5,516,385		5,516,385	9
	250,771	250,771		7,523,130		7,523,130	10
	631,254	631,254		27,768,863		27,768,863	11
5,975				660,119	-606	659,513	12
7,748				840,806	-766	840,040	13
69,507			-295	9,872,371	180,156	10,052,232	14
24,147,129	1,144,710	1,144,710	214,804,884	1,645,244,420	8,071,435	1,868,120,739	

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)	
5,851			-4	377,991	-585	377,402	1
174,261				8,753,116		8,753,116	2
573,593			5	59,571,950	694,602	60,266,557	3
865				114,137		114,137	4
33,877			16,087,540	3,060,607		19,148,147	5
6,629				683,401		683,401	6
7,052				726,821		726,821	7
11,275				1,228,059		1,228,059	8
10,676				1,174,359		1,174,359	9
491,906			64,463,687	29,408,595		93,872,282	10
312,947				36,134,699	-31,294	36,103,405	11
150,881			66,668,397	9,041,640		75,710,037	12
-14,201			2,760,190	554,973		3,315,163	13
35,117			-14	2,333,403	-3,517	2,329,872	14
24,147,129	1,144,710	1,144,710	214,804,884	1,645,244,420	8,071,435	1,868,120,739	

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)	
11,922			2,686	1,401,496		1,404,182	1
405,358			-180,000	29,868,951	3,153,355	32,842,306	2
4,498			-20	583,658	-450	583,188	3
8,375			-50	1,105,373	-838	1,104,485	4
5,988			174	784,310	-599	783,885	5
11,191			-77	1,471,052	-1,119	1,469,856	6
4,218			-9,398	496,139		486,741	7
14,422			-3,474	1,240,577		1,237,103	8
59,936				4,686,017	714,998	5,401,015	9
41,301			9,982,475	1,958,513		11,940,988	10
150,144				15,014,400		15,014,400	11
			-50,000			-50,000	12
			5,777,617			5,777,617	13
			2,900,696			2,900,696	14
24,147,129	1,144,710	1,144,710	214,804,884	1,645,244,420	8,071,435	1,868,120,739	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
			-350,000			-350,000	1
			12,257,613			12,257,613	2
			382,704			382,704	3
1,200				37,600		37,600	4
					57,105	57,105	5
				13,730	171,861	185,591	6
					15,320,934	15,320,934	7
				6,732	8,408	15,140	8
					33,035,384	33,035,384	9
							10
							11
							12
							13
							14
24,147,129	1,144,710	1,144,710	214,804,884	1,645,244,420	8,071,435	1,868,120,739	

Schedule Page: 326 Line No.: 1 Column: l
Curtailment of 32,951 MWh and payment/penalties of $3,538,789. Forcasting Fee.

Schedule Page: 326 Line No.: 4 Column: l
CAISO allocated revenues and charges.

Schedule Page: 326 Line No.: 5 Column: l
Curtailment of 6,060 MWh and payment/penalties of $373,637. Forecasting fees.

Schedule Page: 326 Line No.: 7 Column: l
Curtailment of 31,590 MWh and payment/penalties of $3,217,801. Forecasting fees.

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

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

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

Schedule Page: 326 Line No.: 11 Column: l
Curtailment of 38,237 MWh and payment/penalties of $4,855,298. Forecasting fees.

Schedule Page: 326 Line No.: 12 Column: l
Curtailment of 12,370 MWh and payment/penalties of $1,496,268. Forecasting fees.

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

Schedule Page: 326.1 Line No.: 4 Column: l
Curtailment of 31,593 MWh and payment/penalties of $3,847,909. Forecasting fees.

Schedule Page: 326.1 Line No.: 5 Column: l
Curtailment of 34,800 MWh and payment/penalties of $3,140,314. Forecasting fees.

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

Schedule Page: 326.1 Line No.: 7 Column: l
EPA SO2 proceeds.

Schedule Page: 326.1 Line No.: 9 Column: l
Forecasting fees.

Schedule Page: 326.2 Line No.: 1 Column: l
Curtailment of 51,384 MWh and payments/penalties of $5,282,026. Forecasting fees.

Schedule Page: 326.2 Line No.: 2 Column: l
Curtailment of 1,441 MWh and payments/penalties of $121,000. Forecasting fees.

Schedule Page: 326.2 Line No.: 3 Column: l
Curtailment of 3,950 MWh and payments/penalties of $375,076.

Schedule Page: 326.2 Line No.: 4 Column: l
Forecasting fees.

Schedule Page: 326.2 Line No.: 5 Column: l
Forecasting fees.

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

Schedule Page: 326.2 Line No.: 13 Column: l
Forecasting fees.

Schedule Page: 326.2 Line No.: 14 Column: l
Curtailment of 1,208 MWh and payments/penalties of $177,929. Forecasting fees.

Schedule Page: 326.3 Line No.: 1 Column: l
Forecasting fees.

Schedule Page: 326.3 Line No.: 3 Column: l
Curtailment of 6,230 MWh and payments/penalties of $721,790. Forecasting fees.

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

Forecasting fees.

Schedule Page: 326.3 Line No.: 14 Column: l

Forecasting fees.

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

Curtailment of 20,063 MWh and payments/penalties of $3,253,959.

Schedule Page: 326.4 Line No.: 3 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 4 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 5 Column: l

Forecasting fees.

Schedule Page: 326.4 Line No.: 6 Column: l

Forecasting fees.

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

Curtailment of 8,161 MWh and payments/penalties of $665,618. Forecasting fees.

Schedule Page: 326.5 Line No.: 5 Column: l

Software & support.

Schedule Page: 326.5 Line No.: 6 Column: l

Contract administration expenses.

Schedule Page: 326.5 Line No.: 7 Column: l

Contract hedging activity.

Schedule Page: 326.5 Line No.: 8 Column: l

Engineering services.

Schedule Page: 326.5 Line No.: 9 Column: l

Amortization of GHG Allowances.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	CAISO	N/A	N/A	OS
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
001	N/A	N/A				1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**0**	**0**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
	256,061,609		256,061,609	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	**256,061,609**	**0**	**256,061,609**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	182,144
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,258,357
6	Abandoned Projects	2,033,951
7	Advertising and Marketing	166,333
8	Cost of Financing	275,772
9	FERC Adjustment	2,973,176
10	Fire Insurance	468,685
11	Fleet Derivative	205,319
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	7,563,737

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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			23,971,406		23,971,406
2	Steam Production Plant	21,103,490				21,103,490
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	22,898,423			-8,574	22,889,849
7	Transmission Plant	152,070,526			1,946,847	154,017,373
8	Distribution Plant	251,616,261			1,934,559	253,550,820
9	Regional Transmission and Market Operation					
10	General Plant	17,870,555				17,870,555
11	Common Plant-Electric	33,682,025		43,748,318		77,430,343
12	TOTAL	499,241,280		67,719,724	3,872,832	570,833,836

B. Basis for Amortization Charges

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13	311-Desert Star	29,031					
14	311-Palomar	59,805					
15	312-Desert Star	54,241					
16	312-Palomar	107,503					
17	314-Desert Star	14,495					
18	314-Palomar	116,386					
19	315-Desert Star	46,587					
20	315-Palomar	37,254					
21	316-Desert Star	4,904					
22	316-Palomar	44,791					
23	SUBTOTAL	514,997					
24							
25	OTHER PRODUCTION						
26	341-CPEP	1,870					
27	341-Desert Star	1,751					
28	341-Miramar	5,076					
29	341-Palomar	14,501					
30	342-CPEP	627					
31	342-Desert Star	594					
32	342-Miramar	5,233					
33	342-Palomar	14,914					
34	343-CPEP	16,862					
35	343-Desert Star	24,351					
36	343-Miramar	53,394					
37	343-Palomar						
38	344-CPEP	1,978					
39	344-Desert Star	108,119					
40	344-Miramar	19,736					
41	344-Palomar	170,813					
42	344-Solar	58,536					
43	344-Wind	257					
44	345-CPEP	834					
45	345-Desert Star	9,194					
46	345-Miramar	13,458					
47	345-Palomar	6,709					
48	345-Solar	2,316					
49	345-Wind						
50	346-CPEP	3,057					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	346-Desert Star	22,342					
13	346-Miramar	3,477					
14	346-Palomar	15					
15	SUBTOTAL	560,014					
16							
17	TRANSMISSION-SWPL						
18	352	16,497					
19	353	275,660					
20	354	62,015					
21	355	10,309					
22	356	46,249					
23	359	5,324					
24	SUBTOTAL	416,054					
25							
26	TRANSMISSION-SRPL						
27	352	121,000					
28	353	161,608					
29	354	766,332					
30	355	3,344					
31	356	173,392					
32	357	80,502					
33	358	126,452					
34	359	227,676					
35	SUBTOTAL	1,660,306					
36							
37	TRANSMISSION-OTHER						
38	352	402,864					
39	353	1,267,453					
40	353.4	1,420					
41	354	70,745					
42	355	556,540					
43	356	418,760					
44	357	318,706					
45	358	313,932					
46	359	85,052					
47	SUBTOTAL	3,435,472					
48							
49	DISTRIBUTION						
50	361	7,575					

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	535,741					
13	363	124,352					
14	364	742,382					
15	365	718,526					
16	366	1,290,636					
17	367	1,585,305					
18	368.1	634,410					
19	368.2	34,519					
20	369.1	167,631					
21	369.2	358,151					
22	370.1	5,083					
23	370.11	190,520					
24	E370.20	6,231					
25	E370.21	51,788					
26	E371.00	9,303					
27	E373.20	15,575					
28	SUBTOTAL	6,477,728					
29							
30	GENERAL						
31	390	43,819					
32	392.2	58					
33	393.1	41					
34	394.11	33,211					
35	394.2	278					
36	395.1	5,310					
37	397.1	274,689					
38	397.2	7,294					
39	397.6	14,037					
40	397.7	287					
41	398.1	8,215					
42	398.2	5,737					
43	SUBTOTAL	392,976					
44							
45	TOTAL	13,457,547					
46							
47	SEE FOOTNOTE						
48							
49							
50							

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

Reclassification of 2018 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	-	23,971,406	-	23,971,406
Steam Production	21,576,221	-	-	21,576,221
Nuclear Production	-	-	-	-
Other Production	21,207,757	-	(8,574)	21,199,183
Transmission Plant	150,374,705	-	1,936,390	152,311,095
Distribution Plant	254,530,017	-	1,945,016	256,475,033
General Plant	17,870,555	-	-	17,870,555
Common Plant-Electric	33,682,025	43,748,318	-	77,430,343
Total Ratemaking Electric Depreciation & Amort.	499,241,280	67,719,724	3,872,832	570,833,836

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.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.17-11-028 RESIDENTIAL RATE STRUCTURES		8,390	8,390	
2			987	987	
3					
4	D.17-11-032 NATURAL GAS PIPELINES AND FAC		2,599	2,599	
5					
6	D.18-01-015 UPDATE ELECTRIC RATE DESIGN		94,098	94,098	
7					
8	D.18-01-017 UPDATE ELECTRIC RATE DESIGN		15,865	15,865	
9					
10	D.18-01-021 UPDATE ELECTRIC RATE DESIGN		155,839	155,839	
11					
12	D.18-02-014 RECOVER REVENUE REQUIREMENT		41,563	41,563	
13			5,517	5,517	
14					
15	D.18-02-015 DEMAND RESPONSE		16,119	16,119	
16					
17	D.18-02-016 INTERVENER COMPENSATION		2,281	2,281	
18			317	317	
19					
20	D.18-03-008 ELECTRIC PROCUREMENT POLICY		14,263	14,263	
21					
22	D.18-03-009 AUTHORIZED COST OF CAPITAL		1,520	1,520	
23			212	212	
24					
25	D.18-03-033 NATURAL GAS PIPELINES AND FAC		25,383	25,383	
26					
27	D.18-03-034 SOLAR GENERATED ELECTRICITY		204	204	
28					
29	D.18-04-024 ENERGY EFFICIENCY		1,147	1,147	
30			159	159	
31					
32	D.18-05-015 MKTG, EDU & OUTREACH PROGRAM		3,957	3,957	
33			549	549	
34					
35	D.18-05-016 FIRE-THREAT MAPS AND FIRE-SAFETY		4,466	4,466	
36					
37	D.18-05-017 ENERGY EFFICIENCY		62,818	62,818	
38			7,391	7,391	
39					
40	D.18-05-018 ENERGY SAVINGS ASSISTANCE		6,518	6,518	
41			907	907	
42					
43	D.18-05-035 ENERGY STORAGE		4,169	4,169	
44					
45	D.18-05-036 2007 SOUTHERN CAL WILDFIRES		37,526	37,526	
46	TOTAL	9,928,871	15,891,734	25,820,605	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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					
2	D.18-05-037 FIRE-THREAT MAPS AND FIRE-SAFETY		5,056	5,056	
3					
4	D.18-05-038 PARTNERSHIP FRAMEWORK		5,318	5,318	
5			626	626	
6					
7	D.18-05-039 ENERGY SAVINGS ASSISTANCE		3,029	3,029	
8			421	421	
9					
10	D.18-06-022 DEVELOPMENT OF DIST RESOURCES		1,346	1,346	
11					
12	D.18-06-023 DAIRY BIOMETHANE PILOT PROJECTS		708	708	
13					
14	D.18-06-024 2007 SOUTHERN CAL WILDFIRES		236,422	236,422	
15					
16	D.18-06-025 ELECTRICITY INTEGRATED RESOURCE		10,540	10,540	
17					
18	D.18-06-026 RES RATE STRUCTURES		33,809	33,809	
19					
20	D.18-07-018 SUNRISE POWERLINK		49,430	49,430	
21					
22	D.18-07-019 ELECTRICITY INTEGRATED RESOURCE		22,523	22,523	
23					
24	D.18-07-020 ENERGY STORAGE PROCUREMENT		13,652	13,652	
25					
26	D.18-07-022 ENERGY STORAGE PROCUREMENT		7,021	7,021	
27					
28	D.18-07-034 2007 SOUTHERN CAL WILDFIRES		77,492	77,492	
29					
30	D.18-07-036 TRANSPORTATION ELECTRIFICATION		4,472	4,472	
31					
32	D.18-08-009 TRANSPORTATION ELECTRIFICATION		3,963	3,963	
33					
34	D.18-08-012 ELECTRICITY INTEGRATED RESOURCE		32,667	32,667	
35					
36	D.18-08-024 ENERGY EFFICIENCY		2,487	2,487	
37			346	346	
38					
39	D.18-09-039 ELECTRICITY INTEGRATED RESOURCE		7,414	7,414	
40					
41	D.18-09-040 RES RATE STRUCTURES		6,280	6,280	
42					
43	D.18-09-041 ENERGY SAVINGS ASSISTANCE		722	722	
44			101	101	
45					
46	TOTAL	9,928,871	15,891,734	25,820,605	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.18-09-042 2007 SOUTHERN CAL WILDFIRES		62,198	62,198	
2					
3	D.18-09-043 INTEGRATED RESOURCE PLANNING		18,464	18,464	
4					
5	D.18-10-016 INTEGRATED RESOURCE PLANNING		3,445	3,445	
6					
7	D.18-10-018 TRANSPORTATION ELECTRIFICATION		8,086	8,086	
8					
9	D.18-10-043 INTEGRATED RESOURCE PLANNING		12,420	12,420	
10					
11	D.18-10-046 INTEGRATED RESOURCE PLANNING		8,662	8,662	
12					
13	D.18-10-047 DISTRIBUTION RESOURCE PLAN		3,708	3,708	
14					
15	D.18-10-048 TRANSPORTATION ELECTRIFICATION		9,460	9,460	
16					
17	D.18-10-051 INTEGRATED RESOURCE PLANNING		25,049	25,049	
18					
19	D.18-11-011 ENERGY SAVINGS ASSISTANCE		2,969	2,969	
20			413	413	
21					
22	D.18-11-041 TRANSPORTATION ELECTRIFICATION		12,025	12,025	
23					
24	D.18-11-042 TRANSPORTATION ELECTRIFICATION		1,474	1,474	
25					
26	D.18-11-043 TRANSPORTATION ELECTRIFICATION		48,622	48,622	
27					
28	D.18-11-045 WATER ENERGY NEXUS PROGRAM		16,332	16,332	
29			1,922	1,922	
30					
31	D.18-11-046 TRANSPORTATION ELECTRIFICATION		11,087	11,087	
32					
33	D.18-11-047 TRANSPORTATION ELECTRIFICATION		95,478	95,478	
34					
35	California Public Utilities Commission fees	8,872,402		8,872,402	
36		1,056,469		1,056,469	
37					
38	FERC Proceedings		53,654	53,654	
39					
40	SETTLEMENT REFUND LITIGATION RESO E-3893		6,100	6,100	
41					
42	MISCELLANEOUS		10,694,224	10,694,224	
43			3,755,333	3,755,333	
44					
45					
46	TOTAL	9,928,871	15,891,734	25,820,605	

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	8,390					1
Gas	928	987					2
							3
Gas	928	2,599					4
							5
Elec	928	94,098					6
							7
Elec	928	15,865					8
							9
Elec	928	155,839					10
							11
Elec	928	41,563					12
Gas	928	5,517					13
							14
Elec	928	16,119					15
							16
Elec	928	2,281					17
Gas	928	317					18
							19
Elec	928	14,263					20
							21
Elec	928	1,520					22
Gas	928	212					23
							24
Gas	928	25,383					25
							26
Elec	928	204					27
							28
Elec	928	1,147					29
Gas	928	159					30
							31
Elec	928	3,957					32
Gas	928	549					33
							34
Elec	928	4,466					35
							36
Elec	928	62,818					37
Gas	928	7,391					38
							39
Elec	928	6,518					40
Gas	928	907					41
							42
Elec	928	4,169					43
							44
Elec	928	37,526					45
		25,820,605					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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Elec	928	5,056					2
							3
Elec		5,318					4
Gas		626					5
							6
Elec	928	3,029					7
Gas	928	421					8
							9
Elec	928	1,346					10
							11
Gas	928	708					12
							13
Elec	928	236,422					14
							15
Elec	928	10,540					16
							17
Elec	928	33,809					18
							19
Elec	928	49,430					20
							21
Elec	928	22,523					22
							23
Elec	928	13,652					24
							25
Elec	928	7,021					26
							27
Elec	928	77,492					28
							29
Elec	928	4,472					30
							31
Elec	928	3,963					32
							33
Elec	928	32,667					34
							35
Elec	928	2,487					36
Gas	928	346					37
							38
Elec	928	7,414					39
							40
Elec	928	6,280					41
							42
Elec	928	722					43
Gas	928	101					44
							45
		25,820,605					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Elec	928	62,198					1
							2
Elec	928	18,464					3
							4
Elec	928	3,445					5
							6
Elec	928	8,086					7
							8
Elec	928	12,420					9
							10
Elec	928	8,662					11
							12
Elec	928	3,708					13
							14
Elec	928	9,460					15
							16
Elec	928	25,049					17
							18
Elec	928	2,969					19
Gas	928	413					20
							21
Elec	928	12,025					22
							23
Elec	928	1,474					24
							25
Elec	928	48,622					26
							27
Elec	928	16,332					28
Gas	928	1,922					29
							30
Elec	928	11,087					31
							32
Elec	928	95,478					33
							34
Elec	928	8,872,402					35
Gas	928	1,056,469					36
							37
Elec	928	53,654					38
							39
Elec	928	6,100					40
							41
Elec	928	10,694,224					42
Gas	928	3,755,333					43
							44
							45
		25,820,605					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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 Electrical 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	
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
9,949,500		588	9,949,500		9
					10
					11
					12
					13
					14
9,949,500			9,949,500		15
					16
					17
					18
	734,720	588	734,720		19
	226	408	226		20
					21
					22
					23
					24
					25
					26
	1,941,412	588	1,941,412		27
	19,810	408	19,810		28
	2,696,168		2,696,168		29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	9,932,335		
4	Transmission	11,220,074		
5	Regional Market			
6	Distribution	30,464,405		
7	Customer Accounts	17,573,384		
8	Customer Service and Informational	18,899,617		
9	Sales			
10	Administrative and General	37,481,958		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	125,571,773		
12	Maintenance			
13	Production	1,750,231		
14	Transmission	11,265,848		
15	Regional Market			
16	Distribution	14,415,482		
17	Administrative and General	1,401,077		
18	TOTAL Maintenance (Total of lines 13 thru 17)	28,832,638		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,682,566		
21	Transmission (Enter Total of lines 4 and 14)	22,485,922		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	44,879,887		
24	Customer Accounts (Transcribe from line 7)	17,573,384		
25	Customer Service and Informational (Transcribe from line 8)	18,899,617		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	38,883,035		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	154,404,411	46,469,492	200,873,903
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	132,173		
35	Transmission	2,515,361		
36	Distribution	23,985,681		
37	Customer Accounts	8,794,935		
38	Customer Service and Informational	2,169,699		
39	Sales			
40	Administrative and General	13,607,769		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	51,205,618		
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	487,348		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	6,350,531		
49	Administrative and General	495,482		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,333,361		
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	132,173		
56	Transmission (Lines 35 and 47)	3,002,709		
57	Distribution (Lines 36 and 48)	30,336,212		
58	Customer Accounts (Line 37)	8,794,935		
59	Customer Service and Informational (Line 38)	2,169,699		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	14,103,251		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	58,538,979	15,380,812	73,919,791
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	212,943,390	61,850,304	274,793,694
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	68,578,185	114,434,891	183,013,076
69	Gas Plant	13,789,448	18,544,573	32,334,021
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	82,367,633	132,979,464	215,347,097
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,570,100	10,940,971	17,511,071
74	Gas Plant	1,026,460	976,275	2,002,735
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	7,596,560	11,917,246	19,513,806
77	Other Accounts (Specify, provide details in footnote):			
78	3rd Party Billings, Gas		2,100,122	2,100,122
79	3rd Party Billings, Electric		6,557,592	6,557,592
80	Affiliate Billings, Gas		8,534,497	8,534,497
81	Affiliate Billings, Electric		23,683,311	23,683,311
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts		40,875,522	40,875,522
96	TOTAL SALARIES AND WAGES	302,907,583	247,622,536	550,530,119

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

FERC 426 is not included in the detail classification lines or summary totals.
FERC 426 for 2018 amounts to $173,889.82

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account	Balance Beg. of Year	Additions	Retire From Serv.	Adjs.	Transfers	Balance End of Year
303 Misc. Intangible Plant	442,229,213	146,788,177	1,420,636			587,596,754
389 Land & Land Rights	8,351,542	(171)				8,351,371
390 Structures & Improvements	385,914,792	53,272,983	10,178,703			429,009,072
391 Office Furniture & Equipment	73,047,696	32,045,938	8,660,093			96,433,541
392 Transportation Equipment	514,397	11,849,625				12,364,022
393 Stores Equipment	345,382		11,546			333,836
394 Tools, Shop & Garage Equip.	3,270,555	355,600	108,424			3,517,731
395 Laboratory Equipment	1,925,371		194,254			1,731,117
396 Power Operated Equipmennt						
397 Communication Equipment	166,512,763	74,994,663	3,754,520			237,752,906
398 Miscellaneous Equipment	2,238,283	3,247,685	328,371			5,157,597
SPL Topside				5,725,081		5,725,081
FIN 47 ARC - Common	4,307,504			(1,654,742)		2,652,762
Fleet Capital Lease	22,042,512	2,648,613				24,691,125
TOTAL COMMON PLANT	1,110,700,010	325,203,113	36,445,465	4,070,339		1,403,527,997
Construction Work in Progress	244,066,827	(75,449,415)				168,580,320
TOTAL COMMON PLANT	1,354,766,837	249,753,698	36,445,465	4,070,339		1,572,108,317

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

ACCOUNT	December 31, 2018 Accumulated Depreciation
303 Misc. Intangible Plant	359,759,605
389 Land & Land Rights	27,776
390 Structures & Improvements	160,277,276
391 Office Furniture & Equipment	32,031,140
392 Transportation Equipment	1,440,172
393 Stores Equipment	21,261
394 Tools, Shop & Garage Equipment	910,621
395 Laboratory Equipment	787,869
396 Power Operated Equipment	(192,979)
397 Communication Equipment	78,653,396
398 Miscellaneous Equipment	307,608
108.4 Retirement Work in Progress	
FIN 47 Accumulated Depreciation	3,566,226
Fleet Capital Lease	11,002,116
Total Accumulated Depreciation	648,592,087

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

		December 31,2018 Balance End of Year	Accumulated Depreciation
Electric	73.51%	1,031,733,431	476,780,043
Gas	26.49%	371,794,566	171,812,044
Total	100.00%	1,403,527,997	648,592,087

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

ACCOUNT		Ad Valorem Taxes Note (1)	Depreciation Note (2)
ACCOUNT			
303	Misc. Intangible Plant		59,513,423
389	Land & Land Rights		2
390	Structures & Improvements		13,254,470
391	Office Furniture & Equipment		14,577,846
392	Transportation Equipment		1,688,320
393	Stores Equipment		17,675
394	Tools, Shop & Garage Equipment		189,748
395	Laboratory Equipment		77,609
396	Power Operated Equipment		
397	Communication Equipment		15,768,978
398	Miscellaneous Equipment		245,004
	Total		105,333,075

(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 2017-2018 and 2018-2019. 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 2018. Other expenses of operation, maintenance and rents for common utility plant are allocated based on labor percentage studies. Specific amounts charged to operations and maintenance are not readily available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	161,319,420	275,810,169	672,992,014	891,292,023
3	Net Sales (Account 447)	(91,991,163)	(163,279,078)	(424,098,826)	(548,275,634)
4	Transmission Rights				
5	Ancillary Services	349,021	451,328	2,604	(489,473)
6	Other Items (list separately)				
7	Congestion	(3,062)	1,133,829	6,551,811	8,298,779
8	Congestion Revenue Rights	(17,731,281)	(32,809,856)	(60,325,433)	(71,152,363)
9	Grid Management Charges	2,484,511	4,972,730	8,368,059	11,074,242
10	Other	8,946,701	16,058,305	26,956,452	30,604,538
11	Unaccounted for Energy	996,290	1,617,529	(16,562,727)	(12,543,018)
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	64,370,437	103,954,956	213,883,954	308,809,094

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	1,250,042	MWH	11,438,206	2,990,751	MWH	11,927,680
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)	1,250,042		11,438,206	2,990,751		11,927,680

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	2,957	9	17	2,957					
2	February	2,913	21	18	2,913					
3	March	2,794	1	19	2,794					
4	Total for Quarter 1				8,664					
5	April	2,922	10	18	2,922					
6	May	2,734	4	18	2,734					
7	June	2,984	13	19	2,984					
8	Total for Quarter 2				8,640					
9	July	4,303	6	16	4,303					
10	August	4,377	9	16	4,377					
11	September	3,472	14	16	3,472					
12	Total for Quarter 3				12,152					
13	October	3,355	1	18	3,355					
14	November	2,913	29	17	2,913					
15	December	3,106	5	17	3,106					
16	Total for Quarter 4				9,374					
17	Total Year to Date/Year				38,830					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	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)	15,139,011
3	Steam	3,585,700			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage	53,371	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	11,199,395
7	Other	109,556			
8	Less Energy for Pumping	69,705	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	3,678,922	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	31,021
10	Purchases	24,147,129	27	Total Energy Losses	1,456,624
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	27,826,051
12	Received	1,144,710			
13	Delivered	1,144,710			
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)	27,826,051			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	1,275,088	743,420	2,957	9	17
30	February	1,122,657	769,890	2,913	21	18
31	March	1,208,709	851,544	2,794	1	19
32	April	1,097,386	688,967	2,922	10	18
33	May	1,107,008	867,574	2,734	4	18
34	June	1,189,212	933,018	2,984	13	19
35	July	1,356,786	1,173,007	4,303	6	16
36	August	1,612,521	1,317,566	4,377	9	16
37	September	1,523,579	1,122,502	3,472	14	16
38	October	1,240,144	928,896	3,355	1	18
39	November	1,208,733	1,192,492	2,913	29	17
40	December	1,197,188	610,519	3,106	5	17
41	TOTAL	15,139,011	11,199,395			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	5044			1360		
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	32			3		
12	Net Generation, Exclusive of Plant Use - KWh	1887552000			92581000		
13	Cost of Plant: Land and Land Rights	14480000			0		
14	Structures and Improvements	76973268			5075863		
15	Equipment Costs	513914786			98355944		
16	Asset Retirement Costs	0			0		
17	Total Cost	605368054			103431807		
18	Cost per KW of Installed Capacity (line 17/5) Including	1069.5549			1077.4147		
19	Production Expenses: Oper, Supv, & Engr	1497029			154575		
20	Fuel	66443849			4523782		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4345531			60565		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3147892			332691		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	2905			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	195605			0		
31	Maintenance of Boiler (or reactor) Plant	244241			0		
32	Maintenance of Electric Plant	4296396			1677480		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			8440		
34	Total Production Expenses	80173448			6757533		
35	Expenses per Net KWh	0.0425			0.0730		
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	13209574	0	0	915406	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	5.030	0.000	0.000	4.942	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.922	0.000	0.000	4.835	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.000	0.000	0.049	0.000	0.000
44	Average BTU per KWh Net Generation	7187.000	0.000	0.000	10155.000	0.000	0.000

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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			402			0			7
450			47			0			8
450			47			0			9
450			47			0			10
23			1			0			11
1661880970			14888000			0			12
0			0			0			13
30877505			1882477			0			14
300430401			24720002			0			15
109537			0			0			16
331417443			26602479			0			17
618.3161			566.0102			0			18
773074			107652			0			19
58028144			967317			0			20
0			0			0			21
1795399			15959			0			22
0			0			0			23
0			0			0			24
906530			143906			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			13634			0			30
2037726			0			0			31
8141802			394825			0			32
1379047			11267			0			33
73061722			1654560			0			34
0.0440			0.1111			0.0000			35
GAS			GAS						36
MCF			MCF						37
12445531	0	0	166143	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
4.663	0.000	0.000	5.822	0.000	0.000	0.000	0.000	0.000	41
4.562	0.000	0.000	5.697	0.000	0.000	0.000	0.000	0.000	42
0.035	0.000	0.000	0.065	0.000	0.000	0.000	0.000	0.000	43
7691.000	0.000	0.000	11461.000	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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
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			3
			4
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			12
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			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	J&D Labs Fuel Cell	2012	0.40	0.4	880	3,002,210
2						
3						
4						
5						
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8						
9						
10						
11						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	42,436	47,116	27,282	Gas	596	1
						2
						3
						4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Miguel	East County	500.00	500.00	1S, 3	53.59		1
2	Imperial Valley	North Gila	500.00	500.00	1S, 3	79.45		1
3	North Gila	Palo Verde	500.00	500.00	3	114.45		1
4	Suncrest	Ocotillo Switchyard	500.00	500.00	3	67.48		1
5	East County	Imperial Valley	500.00	500.00	1S, 3	30.74		1
6	Ocotillo Switchyard	Imperial Valley	500.00	500.00	3	21.60		1
7	Ocotillo Switchyard	Ocotillo Express Sub	500.00	500.00	3	0.06		1
8	Total 500kV Pole Line Mi					367.37		7
9	San Luis Rey		230.00	230.00	1S, 3		30.48	2
10			230.00	230.00	2W	4.26		1
11		Mission	230.00	230.00	4		0.05	2
12	San Onofre		230.00	230.00	2S		0.43	5
13			230.00	230.00	2S, 3		16.76	2
14		San Luis Rey	230.00	230.00	1S, 2W	0.75		1
15	San Luis Rey		230.00	230.00	1S, 3		5.81	2
16		Encina	230.00	230.00	1S, 3		1.49	2
17	San Luis Rey		230.00	230.00	2W	4.26		1
18			230.00	230.00	1S, 3		30.48	2
19		Mission	230.00	230.00	4		0.05	2
20	San Luis Rey		230.00	230.00	1S, 2W, 3S, 3	17.61		1
21			230.00	230.00	1S		0.07	2
22		San Onofre	230.00	230.00	2S		0.45	5
23	San Onofre		230.00	230.00	1S, 3		6.30	2
24			230.00	230.00	2S, 3		0.50	5
25		Talega	230.00	230.00	3	0.11		1
26	San Onofre		230.00	230.00	2W, 2S	0.75		1
27			230.00	230.00	2S		0.43	5
28		San Luis Rey	230.00	230.00	2S, 3		16.76	2
29	San Luis Rey		230.00	230.00	1S, 3		5.84	2
30			230.00	230.00	1S, 3		1.56	2
31			230.00	230.00	3		7.19	2
32			230.00	230.00	1S		5.16	2
33			230.00	230.00	1S		0.82	2
34		Palomar Energy	230.00	230.00	1S	0.26		1
35	Encina		230.00	230.00	1S, 3		17.91	2
36					TOTAL	1,455.12	649.54	509

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		Penasquitos	230.00	230.00	1S		0.12	2
2	Penasquitos		230.00	230.00	1S		2.20	2
3		Old Town	230.00	230.00	1S	7.19		1
4	Palomar		230.00	230.00	1S		0.18	2
5		Old Town	230.00	230.00	1S		0.22	2
6	Palomar		230.00	230.00	1S		0.18	2
7		Old Town	230.00	230.00	1S		0.22	2
8	East County	Eco Gen 1	230.00	230.00	1S		0.23	2
9	Miguel		230.00	230.00	1S, 3		23.29	2
10			230.00	230.00	3		0.67	2
11		Sycamore Canyon	230.00	230.00	1S, 3		3.91	2
12	Miguel		230.00	230.00	1S, 3		9.08	2
13			230.00	230.00	1S, 3		14.84	2
14			230.00	230.00	1S		1.45	2
15			230.00	230.00	1S, 3		1.19	2
16		Mission	230.00	230.00	1S		7.51	2
17	Miguel		230.00	230.00	1S		9.17	2
18			230.00	230.00	1S		0.82	2
19			230.00	230.00	1S, 3		9.28	2
20		Mission	230.00	230.00	1S, 3		14.82	2
21	Bay Boulevard		230.00	230.00	4	2.83		1
22			230.00	230.00	4	0.57		1
23		Silvergate	230.00	230.00	1S, 3	3.86		1
24	Old Town		230.00	230.00	1S	0.10		1
25		Mission	230.00	230.00	1S		3.77	2
26	Old Town		230.00	230.00	1S	0.09		1
27			230.00	230.00	1S		3.80	2
28	Old Town		230.00	230.00	4		7.05	2
29		Silvergate	230.00	230.00	4		0.59	2
30	Old Town		230.00	230.00	4		7.05	2
31		Silvergate	230.00	230.00	4		0.59	2
32	Talega		230.00	230.00	1S, 3	34.24		1
33			230.00	230.00	3		7.69	2
34		Escondido	230.00	230.00	1S, 3		9.12	2
35	Otay Mesa		230.00	230.00	1S	0.11		1
36					TOTAL	1,455.12	649.54	509

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1		Tijuana	230.00	230.00	3	1.60		1
2	Otay Mesa	Miguel	230.00	230.00	1S, 3		8.88	2
3	Miguel		230.00	230.00	1S, 3		23.60	2
4			230.00	230.00	3		0.67	2
5		Sycamore	230.00	230.00	3		3.64	2
6	Otay Mesa	Miguel	230.00	230.00	1S, 3		8.92	2
7	Miguel		230.00	230.00	1S		0.48	2
8		Bay Blvd	230.00	230.00	1S	9.35		1
9	Imperial Valley	NOSDGE23043-1	230.00	230.00	1S	0.04		1
10	IV Bay 12N	NOSDGE23045-6	230.00	230.00	1S	0.06		2
11	IV Bay 13N	NOSDGE23045-6	230.00	230.00	1S	0.06		2
12	IV Bay 13S	NOSDGE23047-8	230.00	230.00	1S	0.09		2
13	IV Bay 14S	NOSDGE23047-8	230.00	230.00	1S	0.09		2
14	Imperial Valley	La Rosita	230.00	230.00	1S, 2S, 3		5.75	2
15	Palomar Energy		230.00	230.00	1S		0.81	2
16			230.00	230.00	1S, 3		12.46	2
17			230.00	230.00	3	6.18		1
18			230.00	230.00	1S		4.75	2
19		Syamore	230.00	230.00	1S	0.36		1
20	Talega		230.00	230.00	3	0.11		1
21			230.00	230.00	1S, 3		6.30	2
22		San Onofre	230.00	230.00	2S		0.50	2
23	Encina		230.00	230.00	1S, 3		10.09	2
24		Penasquitos	230.00	230.00	1S, 3		7.90	2
25	Sycamore Canyon		230.00	230.00	1S, 3		21.75	2
26		Suncrest	230.00	230.00	4		6.23	2
27	Sycamore Canyon		230.00	230.00	1S, 3		21.75	2
28		Suncrest	230.00	230.00	4		6.23	2
29	Imperial Valley	NOSDGE23061-1	230.00	230.00	1S	0.06		1
30	Imperial Valley		230.00	230.00	1S		2.78	2
31			230.00	230.00	2S		0.11	2
32			230.00	230.00	3		2.34	2
33		Drew Switchyard	230.00	230.00	3S		0.10	1
34	Drew Switchyard	NOSDGE23067-1	230.00	230.00	1S	0.04		1
35	Drew Switchyard	NOSDGE23068-1	230.00	230.00	1S	0.04		1
36					TOTAL	1,455.12	649.54	509

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Pio Pico Generation	Otay Mesa	230.00	230.00	1S	0.04		1
2	Penasquitos		230.00	230.00	1S		2.83	2
3			230.00	230.00	4	10.54		1
4			230.00	230.00	4	0.93		1
5		Sycamore Canyon	230.00	230.00	4	0.39		1
6	Encina	Encina Gen 1	230.00	230.00	4	0.03		1
7	San Luis Rey		230.00	230.00	1S		0.09	2
8		GIS Terminal	230.00	230.00	4		0.10	2
9	San Luis Rey		230.00	230.00	1S		0.09	2
10		GIS Terminal	230.00	230.00	4		0.09	2
11	Imperial Valley	Phase Shifting Tran	230.00	230.00	1S		0.17	2
12	Z172244	Z172242	230.00	230.00	1S		0.07	2
13	Z189533	Z189535	230.00	230.00	3	0.27		1
14	East County	Eco Gen 1	230.00	230.00	3		0.23	2
15	Drew Switchyard		230.00	230.00	1S		2.39	2
16		Z46503	230.00	230.00	3		2.71	2
17	Total 230kV Pole Line Mi					107.27	452.39	207
18	Encina Switchyard		138.00	230.00	1S		0.04	2
19		Cannon	138.00	230.00	1S		0.11	2
20	Encina Switchyard		138.00	230.00	1S, 3		1.47	2
21			138.00	230.00	2W, 1S, 2S, 3	17.01		1
22	Z105030	Batiquitos	138.00	230.00	4	0.72		1
23			138.00	230.00	4	0.72		1
24		Penasquitos	138.00	230.00	3		3.33	2
25	Palomar		138.00	138.00	1S	0.03		1
26		Batiquitos	138.00	230.00	1S		2.68	2
27	Encina Switchyard		138.00	230.00	1S, 3		1.48	2
28		Palomar	138.00	230.00	1S, 2S, 3		1.61	2
29	Telegraph Canyon	Proctor Valley	138.00	138.00	1W, 1S, 3		2.60	2
30	Friars		138.00	138.00	4	0.17		1
31			138.00	138.00	1S, 3		4.11	2
32			138.00	138.00	1S, 3		1.82	2
33			138.00	138.00	1S, 3	5.43		1
34		Penaquitos	138.00	138.00	1S, 3		1.40	2
35	Doublet Tap		138.00	138.00	1W, 1S		0.52	3
36					TOTAL	1,455.12	649.54	509

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1		Doublet	138.00	138.00	1W, 1S		0.79	2
2	Shadowridge	Z119772	138.00	138.00	1S		3.74	2
3	Z119772		138.00	138.00	1W,1S, 3	0.20		1
4		NC Metering	138.00	138.00	1W	0.39		1
5	Z119772		138.00	230.00	3		1.11	2
6		Chicarita	138.00	138.00	2W, 2S	10.91		1
7	Telegraph Canyon		138.00	138.00	1S	0.03		1
8			138.00	138.00	3		5.80	2
9			138.00	138.00	4	4.04		1
10	Z223732		138.00	138.00	3			1
11		Z189532	138.00	138.00	3	3.79		1
12			138.00	138.00	3	0.39		1
13		Grant Hill	138.00	138.00	1W. 1S	1.01		1
14	Capistrano		138.00	138.00	1W	0.10		1
15			138.00	138.00	1S, 3		1.56	2
16			138.00	138.00	1S, 3		4.69	2
17		Pico	138.00	138.00	4		0.32	2
18	Santee		138.00	138.00	1W,1S	2.34		1
19			138.00	138.00	1S		4.61	2
20			138.00	138.00	2S	0.27		1
21		Los Coches	138.00	138.00	2S	0.08		1
22	Sycamore		138.00	138.00	4	0.20		1
23		Chicarita	138.00	138.00	1W, 2W,1S, 2S	5.78		1
24	Sycamore		138.00	138.00	1S		6.65	2
25		Santee	138.00	138.00	1W, 1S	1.55		1
26	Mission		138.00	138.00	1W	0.09		1
27			138.00	138.00	1S, 3		3.23	2
28	Z677977	Z874970	138.00	138.00	3	4.97		2
29	Z874970	Carlton Hills	138.00	138.00	1S, 3		1.48	2
30	Telegraph Canyon		138.00	138.00	1S	0.04		1
31			138.00	138.00	1S, 3		2.55	2
32		Miguel 60 Tap	138.00	138.00	1S, 3		0.61	2
33	Miguel 60 Tap	Miguel	138.00	138.00	1S		0.95	2
34	Miguel 60 Tap	Z119793	138.00	138.00	1S	0.02		1
35	Z119793	Z200591	138.00	138.00	1S, 2S	0.50		1
36					TOTAL	1,455.12	649.54	509

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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1			138.00	138.00	1S, 3		13.49	2
2		Los Coches	138.00	138.00	1S, 3		1.41	2
3	Batiquitos		138.00	138.00	1S		2.61	2
4		Shadowridge	138.00	138.00	1S		3.73	2
5	Miguel		138.00	138.00	1S	0.72		1
6		Protor Valley	138.00	138.00	1S, 3		0.61	2
7	Friars		138.00	138.00	4	0.09		1
8		Mission	138.00	138.00	1S ,3		1.26	2
9	Sycamore		138.00	138.00	1S		3.85	2
10			138.00	138.00	1S		1.78	2
11		Carlton Hills	138.00	138.00	1S, 3		1.48	2
12	Trabuco		138.00	138.00	1S	0.68		1
13			138.00	138.00	1S	0.08		1
14			138.00	138.00	4	3.03		1
15		Margarita	138.00	138.00	4	0.23		1
16	Talega	Rancho Mission Viejo	138.00	138.00	1S,1W	6.42		1
17	Trabuco		138.00	138.00	1S,1W	3.66		1
18			138.00	138.00	1W, 3		0.16	2
19			138.00	138.00	1S, 3		6.34	2
20		Pico	138.00	138.00	4		0.32	2
21	Capistrano		138.00	138.00	1W	3.59		1
22		Trabuco	138.00	138.00	1W		0.15	2
23	San Mateo	Talega	138.00	138.00	1S,1W	1.29		1
24	Talega Tap		138.00	138.00	3,1W		2.96	2
25			138.00	138.00	1W,2W,1S,2S,	8.10		1
26			138.00	138.00	4		1.84	2
27		Laguna Niguel	138.00	138.00	4	0.35		1
28	Pico		138.00	138.00	1S, 3		0.70	2
29		Talega	138.00	138.00	1W	0.41		1
30	Capistrano		138.00	138.00	1W	0.01		1
31			138.00	138.00	1W		0.15	2
32			138.00	138.00	1S,1W	1.36		1
33		Laguna Niguel	138.00	138.00	4		1.84	2
34	Rancho Mission Viejo	Margarita	138.00	138.00	1W, 1S	3.06		1
35	Mission		138.00	138.00	1S, 1W	2.56		1
36					TOTAL	1,455.12	649.54	509

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1		Grant Hill	138.00	138.00	4	2.84		1
2	Cannon	Encina Hub	138.00	138.00	1S, 3		1.29	2
3	Encina Hub	Shadowridge	138.00	138.00	1S, 2S, 2W	6.73		1
4	East County		138.00	138.00	1S, 2S	6.99		1
5			138.00	138.00	4	5.54		1
6			138.00	138.00	4	1.12		1
7		Boulevard East	138.00	138.00	4	0.18		1
8	Pico		138.00	138.00	3		0.70	2
9		Talega	138.00	138.00	1W, 1S	0.47		1
10	Talega		138.00	138.00	3		2.78	2
11		San Mateo	138.00	138.00	1S		0.73	2
12	Encina	Z124528	138.00	230.00	1S		0.04	2
13	Z124528	Cannon	138.00	230.00	1S		0.11	2
14	Boulevard	Boulevard East	138.00	138.00	4		0.99	1
15	East County	Eco Gen 2	138.00	138.00	1S	0.33		1
16	Encina	Encina Gen 1	138.00	138.00	3S	0.03		1
17	13822	De-Energized	138.00	138.00	2W	0.06		1
18	13832	De-Energized	138.00	138.00	3, 1S, 1W	3.36		1
19	13832	De-Energized	138.00	138.00	3, 1S, 1W	3.21		1
20	13811	De-Energized	138.00	138.00	1S	1.07		1
21	13811	De-Energized	138.00	138.00	3	5.69		1
22	Cannon	Encina Hub	138.00	138.00	1S, 3		1.28	2
23	Encina Hub	Calavera Tap	138.00	138.00	2W	0.39		1
24	Encina Hub	Calavera Tap	138.00	138.00	2W	2.94		1
25	Calavera Tap	San Luis Rey	138.00	138.00	2W	3.89		1
26	Bay Blvd		138.00	138.00	3		2.82	2
27		Telegraph Canyon	138.00	138.00	3		2.98	2
28	Total 138kV Pole Line Mi					141.26	117.66	170
29					1W	706.78	25.40	125
30					2W	7.11	1.38	
31					1S	43.23	1.50	
32					3	20.00	50.61	
33					4	62.10	0.60	
34	Total of 69kV Pole Line Mi					839.22	79.49	125
35								
36					TOTAL	1,455.12	649.54	509

TRANSMISSION LINE STATISTICS

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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.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1								
2	Cost of Line							
3	Expenses, Except ISO Charge							
4	ISO Charges							
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	1,455.12	649.54	509

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	
2-2156 ACSR								1
2-2156 ACSR								2
2-2156 ACSR								3
3-1033.5 ACSR								4
2-2156 ACSR								5
3-1033.5 ACSR								6
2-1590 ACSR								7
								8
1-1033.5 ACSR/AW								9
1-1033.5 ACSR/AW								10
1-5000 KCMIL CU								11
2-1033.5 ACSR/AW								12
2-1033.5 ACSR/AW								13
2-1033.5 ACSR/AW								14
2-1033.5 ACSR/AW								15
2-1109 ACAR								16
1-1033.5 ACSR/AW								17
1-1033.5 ACSR/AW								18
1-5000 KCMIL CU								19
1-1033.5 ACSR/AW								20
1-1033.5 ACSR/AW								21
2-1033.5 ACSR/AW								22
1-1033.5 ACSR/AW								23
2-1033.5 ACSR/AW								24
2-1033.5 ACSR/AW								25
2-1033.5 ACSR/AW								26
2-1033.5 ACSR/AW								27
2-1033.5 ACSR/AW								28
2-1033.5 ACSR/AW								29
2-1109 ACAR								30
2-1109 ACAR								31
2-1109 ACAR								32
2-900 ACSS/AW								33
2-1109 ACAR								34
2-1109 ACAR								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-1033.5 ACSR/AW								1
2-1033.5 ACSR/AW								2
2-1109 ACAR								3
2-900 ACSS/AW								4
2-605 ACSS/AW								5
2-900 ACSS/AW								6
2-605 ACSS/AW								7
2-1113 ACSS/AW								8
2-1033.5 ACSR/AW								9
2-605 ACSS/AW								10
2-900 ACSS/AW								11
2-605 ACSS/AW								12
2-636 ACSS/AW								13
2-1033.5 ACSR/AW								14
2-1109 ACAR								15
1-1109 ACAR								16
2-605 ACSS/AW								17
2-1109 ACAR								18
2-1033.5 ACSR/AW								19
2-636 ACSS/AW								20
2-3500 KCMIL CU								21
2-4000 KCMIL CU								22
2-900 ACSS/AW								23
2-1109 ACAR								24
1-1109 ACAR								25
2-1109 ACAR								26
1-1109 ACAR								27
1-3500 KCMIL CU								28
1-2500 KCMIL CU								29
1-3500 KCMIL CU								30
1-2500 KCMIL CU								31
1-1033.5 ACSR/AW								32
1-1033.5 ACSR/AW								33
1-1033.5 ACSR/AW								34
2-900 ACSS/AW								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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) 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.
2-1033.5 ACSR/AW								1
2-900 ACSS/AW								2
2-1033.5 ACSR/AW								3
2-605 ACSS/AW								4
2-1109 ACAR								5
2-900 ACSS/AW								6
2-900 ACSS/AW								7
2-900 ACSS/AW								8
2-1033.5 ACSS/AW								9
2-1113 ACSR								10
2-1113 ACSR								11
2954 AL								12
2954 AL								13
2-900 ACSS/AW								14
2-900 ACSS/AW								15
2-1109 ACAR								16
2-1109 ACAR								17
2-1033.5 ACSR/AW								18
2-1033.5 ACSR/AW								19
2-1033.5 ACSR/AW								20
1-1033.5 ACSR/AW								21
2-1033.5 ACSR/AW								22
2-1109 ACAR								23
2-1033.5 ACSR/AW								24
2-900 ACSS/AW								25
2-4000 KCMIL CU								26
2-900 ACSS/AW								27
2-4000 KCMIL CU								28
2-900 ACSS/AW								29
2-900 ACSS/AW								30
2-900 ACSS/AW								31
2-900 ACSS/AW								32
2-900 ACSS/AW								33
2-900 ACSS/AW								34
2-900 ACSS/AW								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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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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)	
1-1272 ACSS								1
2-900 ACSS/AW								2
2-4000 KCMIL CU								3
2-4000 KCMIL CU								4
2-5000 KCMIL CU								5
1-3500 CU								6
2-1033.5 ACSR/AW								7
1-5000 KCMIL CU								8
2-1033.5 ACSR/AW								9
1-5000 KCMIL CU								10
2-900 ACSS/AW								11
2-1033.5 ACSR/AW								12
1-1033.5 ACSR/AW								13
2-1113 ACSS/AW								14
2-900 ACSS/AW								15
2-900 ACSS/AW								16
								17
2-1033.5 ACSR/AW								18
2-1109 ACAR								19
2-1109 ACAR								20
2-636 ACSR/AW								21
1-1750 MCM AL								22
2-1750 MCM AL								23
2-1033.5 ACSR/AW								24
2-1033.5 ACSR/AW								25
2-1109 ACAR								26
2-1109 ACAR								27
2-1033.5 ACSR/AW								28
2-636 ACSS/AW								29
2-2500 CU								30
1-636 ACSR/AW								31
1-400 MCM CU								32
1-636 ACSR/AW								33
1-636 ACSR/AW								34
1-336 ACSR/AW								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	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)	
1-336 ACSR/AW								1
1-1033.5 ACSR/AW								2
1-250 MCM CU								3
1-336.4 ACSR/AW								4
2-1033.5 ACSR/AW								5
1-636 ACSR/AW								6
2-1033.5 ACSR/AW								7
2-636 ACSR/AW								8
1-2500 KCMIL CU								9
1-1033.5 ACSR/AW								10
2-400 MCM CU								11
2-636 ACSS/AW								12
2-636 ACSR/AW								13
1-1033.5 ACSR/AW								14
1-1033.5 ACSR/AW								15
1-636 ACSR/AW								16
1-1750 MCM CU								17
1-1033.5 ACSR/AW								18
1-605 ACSS/AW								19
2-336 ACSR/AW								20
2-636 ACSR/AW								21
1-3000 KCMIL CU								22
1-636 ACSR/AW								23
1-900 ACSS/AW								24
1-900 ACSS/AW								25
2-336.4 ACSR								26
2-336.4 ACSR								27
4-336.4 ACSR								28
1-900 ACSS/AW								29
2-1033.5 ACSR//AW								30
2-636 ACSR/AW								31
2-636 ACSR/AW								32
2-900 ACSS/AW								33
2-636 ACSS/AW								34
2-636 ACSR/AW								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1-636 ACSS/AW								1
1-636 ACSR/AW								2
2-1033.5 ACSR/AW								3
2-1033.5 ACSR/AW								4
2-636 ACSS/AW								5
2-636 ACSR/AW								6
1-1750 KCMIL AL								7
1-900 ACSS/AW								8
1-900 ACSS/AW								9
1-900 ACSS/AW								10
1-900 ACSS/AW								11
1-1033.5 ACSR/AW								12
2-1033.5 ACSR/AW								13
1-1750 KCMIL AL								14
1-1750 KCMIL CU								15
1-1033.5 ACSR/AW								16
1-1033.5 ACSR/AW								17
1-1033.5 ACSR/AW								18
1-1033.5 ACSR/AW								19
1-1750 MCM CU								20
1-1033.5 ACSR/AW								21
1-1033.5 ACSR/AW								22
1-1033.5 ACSR/AW								23
1-336.4 ACSR/AW								24
1-336.4 ACSR/AW								25
1-1750 KCMIL AL								26
1-1750 KCMIL AL								27
1-900 ACSS/AW								28
1-1003.5 ACSR/AW								29
1-636 ACSR/AW								30
1-336.4 ACSR/AW								31
1-336.4 ACSR/AW								32
1-1750 KCMIL AL								33
1-1033.5 ACSR /AW								34
2-636 ACSR/AW								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1-2500 MCM CU								1
2-1109 ACAR								2
1-900 ACSS/AW								3
2-900 ACSS/AW								4
2-2500 KCMIL CU								5
2-3000 KCMIL CU								6
2-5000 KCMIL CU								7
1-1033.5 ACSR/AW								8
1-1033.5 ACSR/AW								9
1-336.4 ACSR/AW								10
1-1033.5 ACSR/AW								11
2-1033.5 ACSR								12
2-1109 ACAR								13
2-2500 KCMIL CU								14
1-636 ACSR/AW								15
1-636 KCMIL ACSR								16
1-1109 ACAR								17
1-336.4 ACSR								18
1-250 MCM CU								19
1-900 ACSS/AW								20
1-250 MCM CU								21
2-1109 ACAR								22
1-1033.5 ACSR/AW								23
1-636 ACSS/AW								24
1-1033.5 ACSR/AW								25
2-636 ACSR/AW								26
2-400 MCM CU								27
								28
								29
								30
								31
								32
								33
								34
								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
	202,127,892	3,475,427,386	3,677,555,278					2
				7,866,983	16,532,185	2,890,113	27,289,281	3
				3,073,920			3,073,920	4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
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								27
								28
								29
								30
								31
								32
								33
								34
								35
	202,127,892	3,475,427,386	3,677,555,278	10,940,903	16,532,185	2,890,113	30,363,201	36

Schedule Page: 422 Line No.: 2 Column: f

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

Schedule Page: 422 Line No.: 3 Column: f

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

Schedule Page: 422 Line No.: 4 Column: f

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Mission	Kearny West	3.64	OH	9.00	1	1
4							
5	Cameron	Crestwood	12.35	OH	9.00	2	2
6							
7	Sycamore Canyon	Penasquitos	2.82	OH	7.00	2	2
8							
9	UNDERGROUND						
10							
11	Mission	Kearny West	3.16	UG		1	1
12							
13	Cameron	Crestwood	0.08	UG		1	1
14							
15	Sycamore Canyon	Chicarita	0.20	UG			
16							
17	Boulevard East	Generator Interconnection	0.99	UG		1	1
18							
19	Sycamore Canyon	Penasquitos	11.85	UG		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		35.09		25.00	9	9

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
1033.5	ACSR/AW	9	69				376,645	376,645	3
									4
1-636	ACSS/AW	9	69	3,495,276	25,481,273	10,450,806	570,726	39,998,081	5
									6
2-900	ACSS/AW	18	230	1,153,985	14,164,470	6,757,802	304,724	22,380,981	7
									8
									9
									10
3000	KCMILCU	8	69			31,980,295		31,980,295	11
									12
3000	KCMILCU	8	69			2,211,283		2,211,283	13
									14
3000	KCMILCU	8	138			2,401,676		2,401,676	15
									16
2500	KCMILCU	8	138						17
									18
4000	KCMILCU	8	230			117,682,136		117,682,136	19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
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									33
									34
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									38
									39
									40
									41
									42
									43
				4,649,261	39,645,743	171,483,998	1,252,095	217,031,097	44

Schedule Page: 424 Line No.: 3 Column: c
To report removal of 3.64 miles for TL663 from Mission to Kearny for 2018.

Schedule Page: 424 Line No.: 5 Column: c
To report addition of 12.36 miles for TL6958 from Cameron to Crestwood for 2018.

Schedule Page: 424 Line No.: 7 Column: c
To report addition of 2.82 miles for TL23071 from Sycamore to Penasquitos for 2018.

Schedule Page: 424 Line No.: 11 Column: c
To report addition of 3.16 miles for TL663 from Mission to Kearny West for 2018.

Schedule Page: 424 Line No.: 13 Column: c
To report removal of 0.08 miles for TL6958 from Cameron to Crestwood for 2018.

Schedule Page: 424 Line No.: 15 Column: c
To report addition of 0.20 miles for TL13820 from Sycamore to Chicarita for 2018.

Schedule Page: 424 Line No.: 17 Column: c
To report addition of 0.99 miles for TL13850 from Boulevard East to Generator Interconnection for 2018.

Schedule Page: 424 Line No.: 19 Column: c
To report addition of 11.86 miles for TL23071 from Sycamore to Penasquitos for 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ALPINE, Alpine	Dist. Unattended	69.00	12.00	
2	AMHERST, San Diego	Dist. Unattended	12.00	4.00	
3	ARTESIAN, San Diego	Dist. Unattended	69.00	12.00	
4	ASH, Escondido	Dist. Unattended	69.00	12.00	
5	AVOCADO, Fallbrook	Dist. Unattended	69.00	12.00	
6	B, San Diego	Dist. Unattended	69.00	12.00	
7	BARRETT, Barrett	Dist. Unattended	69.00	12.00	
8	BASILONE, San Clemente	Dist. Unattended	69.00	12.00	
9	BATIQUITOS, Encinitas	Dist. Unattended	138.00	12.00	
10	BERNARDO, Rancho Bernardo	Dist. Unattended	69.00	12.00	
11	BORDER, San Diego	Dist. Unattended	69.00	12.00	
12	BORREGO, Borrego Springs	Dist. Unattended	69.00	12.00	
13	BOSTONIA, El Cajon	Dist. Unattended	12.00	4.00	
14	BOULDER CREEK, Santa Ysabel	Dist. Unattended	69.00	12.00	
15	BOULEVARD EAST, Boulevard	Dist. Unattended	138.00	12.00	
16	CABRILLO, San Diego	Dist. Unattended	69.00	12.00	
17	CALAVO GARDENS, El Cajon	Dist. Unattended	12.00	4.00	
18	CAMERON, Campo	Dist. Unattended	69.00	12.00	
19	CANNON, Carlsbad	Dist. Unattended	138.00	12.00	
20	CAPISTRANO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
21	CARLTON HILLS, Santee	Dist. Unattended	138.00	12.00	
22	CENTRAL, San Diego	Dist. Unattended	12.00	4.00	
23	CHICARITA, San Diego	Dist. Unattended	138.00	12.00	
24	CHOLLAS, Lemon Grove	Dist. Unattended	69.00	12.00	
25	CHULA VISTA, San Diego	Dist. Unattended	12.00	4.00	
26	CLAIREMONT, San Diego	Dist. Unattended	69.00	12.00	
27	CORONADO, Coronado	Dist. Unattended	69.00	12.00	
28	CREELMAN, Ramona	Dist. Unattended	69.00	12.00	
29	CRESTWOOD, Campo	Dist. Unattended	69.00	12.00	
30	CRISTIANITOS, Mission Viejo	Dist. Unattended	69.00	12.00	
31	DEL MAR, Del Mar	Dist. Unattended	69.00	12.00	
32	DESCANSO, Descanso	Dist. Unattended	69.00	12.00	
33	DIVISION, San Diego	Dist. Unattended	69.00	12.00	
34	DUNHILL, San Diego	Dist. Unattended	69.00	4.00	
35	EAST OCEANSIDE, Oceanside	Dist. Unattended	12.00	4.00	
36	EASTGATE, San Diego	Dist. Unattended	69.00	12.00	
37	EL CAJON, El Cajon	Dist. Unattended	69.00	12.00	
38	ELLIOTT, San Diego	Dist. Unattended	69.00	12.00	
39	ENCANTO, San Diego	Dist. Unattended	12.00	4.00	
40	ENCINITAS, Encinitas	Dist. Unattended	69.00	12.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(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	KEARNY WEST, San Diego	Dist. Unattended	69.00	12.00	
21	KETTNER, San Diego	Dist. Unattended	69.00	12.00	
22	KYOCERA, San Diego	Dist. Unattended	69.00	12.00	
23	LA JOLLA, La Jolla	Dist. Unattended	69.00	12.00	
24	LAGUNA NIGUEL, Laguna Niguel	Dist. Unattended	138.00	12.00	
25	LAS PULGAS, Oceanside	Dist. Unattended	69.00	12.00	
26	LILAC, Valley Center	Dist. Unattended	69.00	12.00	
27	LINCOLN ACRES, National City	Dist. Unattended	12.00	4.00	
28	LOS COCHES, Lakeside	Dist. Unattended	69.00	12.00	
29	LOVELAND, Alpine	Dist. Unattended	69.00	12.00	
30	MARGARITA, Mission Viejo	Dist. Unattended	138.00	12.00	
31	MELROSE, Vista	Dist. Unattended	69.00	12.00	
32	MESA HEIGHTS, San Diego	Dist. Unattended	69.00	12.00	
33	MESA RIM, San Diego	Dist. Unattended	69.00	12.00	
34	MIRAMAR, San Diego	Dist. Unattended	69.00	12.00	
35	MIRA SORRENTO, San Diego	Dist. Unattended	69.00	12.00	
36	MISSION, San Diego	Dist. Unattended	69.00	12.00	
37	MONSERATE, Fallbrook	Dist. Unattended	69.00	12.00	
38	MONTGOMERY, Chula Vista	Dist. Unattended	69.00	12.00	
39	MORRO HILL, Oceanside	Dist. Unattended	69.00	12.00	
40	MURRAY, La Mesa	Dist. Unattended	69.00	12.00	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	NATIONAL CITY, National City	Dist. Unattended	69.00	4.00	12.00
2	NAVAL STATION Switchyard, San Diego-NSM	Dist. Unattended	69.00		
3	NORTH CITY WEST, San Diego	Dist. Unattended	69.00	12.00	
4	NORTH VISTA,Vista	Dist. Unattended	12.00	4.00	
5	OCEANSIDE, Oceanside	Dist. Unattended	69.00	12.00	
6	OLD TOWN, San Diego	Dist. Unattended	69.00	12.00	
7	OLIVENHAIN, Escondido	Dist. Unattended	69.00	12.00	
8	OTAY LAKES, Chula Vista	Dist. Unattended	69.00	12.00	
9	OTAY, Chula Vista	Dist. Unattended	69.00	12.00	
10	PACIFIC BEACH, San Diego	Dist. Unattended	69.00	12.00	
11	PALA, San Diego County	Dist. Unattended	69.00	12.00	
12	PALOMAR AIRPORT, Carlsbad	Dist. Unattended	138.00	12.00	
13	PARADISE, San Diego	Dist. Unattended	69.00	12.00	
14	PENDLETON, Oceanside	Dist. Unattended	69.00	12.00	
15	PICO, San Clemente	Dist. Unattended	138.00	12.00	
16	POINT LOMA SEWAGE, San Diego	Dist. Unattended	12.00	4.00	
17	POINT LOMA, San Diego	Dist. Unattended	69.00	12.00	
18	POMERADO, San Diego	Dist. Unattended	69.00	12.00	
19	POWAY, Poway	Dist. Unattended	69.00	12.00	
20	PROCTOR VALLEY, Bonita	Dist. Unattended	138.00	12.00	
21	RAMONA, Ramona	Dist. Unattended	12.00	4.00	
22	RANCHO CARMEL, San Diego	Dist. Unattended	69.00	12.00	
23	RANCHO MISSION VIEJO, Rancho Mission Viejo	Dist. Unattended	138.00	12.00	
24	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	12.00	
25	RANCHO SANTA FE, Rancho Santa Fe	Dist. Unattended	69.00	4.00	
26	RINCON, Rincon	Dist. Unattended	69.00	12.00	
27	ROLANDO, San Diego	Dist. Unattended	12.00	4.00	
28	ROSE CANYON, San Diego	Dist. Unattended	69.00	12.00	
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

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	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	VINE	Dist. Unattended	69.00	12.00	
15	VISTA, Vista	Dist. Unattended	12.00	4.00	
16	WARNERS, Warner Springs	Dist. Unattended	69.00	12.00	
17	WARREN CANYON, Poway	Dist. Unattended	69.00	12.00	
18	WARREN CANYON, Poway	Dist. Unattended	69.00	4.00	
19	WITHERBY, San Diego	Dist. Unattended	12.00	4.00	
20	BAY BOULEVARD	Trans. Unattended	230.00	69.00	
21	DOUBLETT Switchyard, San Diego	Trans. Unattended	138.00	69.00	
22	EAST COUNTY, Boulevard	Trans. Unattended	500.00	230.00	12.00
23	EAST COUNTY, Boulevard	Trans. Unattended	230.00	138.00	
24	ENCINA Switchyard, Carlsbad	Trans. Unattended	138.00		
25	ENCINA, Carlsbad	Trans. Unattended	230.00	138.00	
26	ESCONDIDO, Escondido	Trans. Unattended	230.00	69.00	
27	GOAL LINE, Escondido	Trans. Unattended	69.00		
28	IMPERIAL VALLEY, El Centro	Trans. Unattended	500.00	230.00	12.00
29	LOS COCHES, Lakeside	Trans. Unattended	138.00	69.00	
30	MIGUEL, Bonita	Trans. Unattended	230.00	69.00	
31	MIGUEL, Bonita	Trans. Unattended	230.00	138.00	
32	MIGUEL, Bonita	Trans. Unattended	500.00	230.00	12.00
33	MIRAMAR GT, San Diego	Trans. Unattended	12.00	69.00	
34	MISSION, San Diego	Trans. Unattended	138.00	69.00	
35	MISSION, San Diego	Trans. Unattended	230.00	69.00	
36	MISSION, San Diego	Trans. Unattended	230.00	138.00	
37	NARROWS, Borrego Springs	Trans. Unattended	88.00	69.00	12.00
38	OCOTILLO Switchyard, Ocotillo	Trans. Unattended	500.00		
39	OLD TOWN, San Diego	Trans. Unattended	230.00	69.00	
40	OTAY MESA Switchyard, Chula Vista	Trans. Unattended	230.00		

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	138.00	69.00	
2	PENASQUITOS, San Diego	Trans. Unattended	230.00	138.00	
3	PENASQUITOS, San Diego	Trans. Unattended	230.00	69.00	
4	SAN LUIS REY, Oceanside	Trans. Unattended	230.00	69.00	
5	SILVERGATE, San Diego	Trans. Unattended	230.00	69.00	
6	SONGS	Trans. Unattended	230.00	230.00	
7	SUNCREST, Japatul	Trans. Unattended	500.00	230.00	12.00
8	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	69.00	
9	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	138.00	
10	TALEGA, San Clemente	Trans. Unattended	138.00	69.00	
11	TALEGA, San Clemente	Trans. Unattended	230.00	138.00	
12	WABASH Switchyard, San Diego	Trans. Unattended	69.00		
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
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31					
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33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	2					1
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					19
112	4	1				20
56	2					21
9	1					22
56	2					23
112	4					24
28	1					25
56	2					26
6	1					27
84	3					28
28	1					29
112	4					30
112	4					31
84	3					32
112	4					33
84	3					34
56	2					35
112	4					36
56	2					37
56	2					38
13	1					39
112	4	1				40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	2					1
						2
56	2					3
3	1					4
56	2					5
84	3	2				6
28	1					7
5	1					8
56	2	1				9
56	2					10
28	1					11
84	3					12
56	2					13
56	2					14
56	2					15
13	1					16
84	3					17
84	3					18
56	2					19
56	2	1				20
6	1					21
84	3					22
56	2					23
41	2					24
6	1					25
25	2					26
13	2					27
56	2					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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	
520	3					1
392	1	1				2
448	2					3
672	3		230/17kV	2	500	4
448	2	1				5
250			230/17Kv	1	250	6
2240	6	1				7
672	3	1				8
392	1	1				9
140	1	1				10
1102	4		230/17kV	2	500	11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Construction Work in Progress	Sempra Energy	107	9,343,617
3	Cost of Removal	Sempra Energy	108	76
4	Other Utility Plant	Sempra Energy	118	305,656
5	Cash	Sempra Energy	131	23,564
6	Other Accounts Receivable	Sempra Energy	143	-189,618
7	Accounts Receivable from Associated Companies	Sempra Energy	146	5,785
8	Stores Expense Undistributed	Sempra Energy	163	3,611
9	Prepayments	Sempra Energy	165	117,668,782
10	Unamortized Debt Expense	Sempra Energy	181	378,790
11	Other Regulatory Assets	Sempra Energy	182	571,852
12	Preliminary Survey and Investigation Charges	Sempra Energy	183	7,112
13	Clearing Accounts	Sempra Energy	184	3,339,307
14	Miscellaneous Deferred Debits	Sempra Energy	186	294,903
15	Research, Development & Demonstration Expenditure	Sempra Energy	188	120,980
16	Accumulated Miscellaneous Operating Provisions	Sempra Energy	228.4	28,950
17	Accounts Payable	Sempra Energy	232	-4,380,421
18	Miscellaneous Current and Accrued Liabilities	Sempra Energy	242	211,355
19	Other Regulatory Liabilities	Sempra Energy	254	-191,549
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Sempra Energy	146	473,554
22	Depreciation Expense	Sempra Energy	146	571,070
23	Environmental Services	Sempra Energy	146	17,831
24	External Affairs	Sempra Energy	146	315,014
25	Fleet Services	Sempra Energy	146	14,467
26	Human Resources	Sempra Energy	146	5,616,787
27	Information Technology	Sempra Energy	146	3,908,020
28	Real Estate & Facilities	Sempra Energy	146	3,742,939
29	Supply Management	Sempra Energy	146	1,122,598
30	Accounting & Finance	U.S Gas & Power Natural Gas	146	804
31	Depreciation Expense	U.S Gas & Power Natural Gas	146	37,613
32	External Affairs	U.S Gas & Power Natural Gas	146	16,216
33	Human Resources	U.S Gas & Power Natural Gas	146	203,014
34	Information Technology	U.S Gas & Power Natural Gas	146	127,352
35	Real Estate & Facilities	U.S Gas & Power Natural Gas	146	18,296
36	Supply Managment	U.S Gas & Power Natural Gas	146	173,689
37	Accounting & Finance	Southern California Gas Company	146	41,384,907
38	Customer Services	Southern California Gas Company	146	531,664
39	Depreciation Expense	Southern California Gas Company	146	3,790,123
40	Engineering and Construction Services	Southern California Gas Company	146	232,631
41	Environmental Services	Southern California Gas Company	146	375,928
42	External Affairs	Southern California Gas Company	146	2,384,149
1	**Non-power Goods or Services Provided by Affiliated**			
2	Civic, Political and Related Activities	Sempra Energy	426.4	642,005

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)
3	Other Electric Revenues	Sempra Energy	456	1,374
4	Operation Supervision and Engineering	Sempra Energy	500	1,408
5	Miscellaneous Steam Power Expenses	Sempra Energy	506	2,002
6	Maintenance of Miscellaneous Steam Plant	Sempra Energy	514	1,161
7	Operation Supervision and Engineering	Sempra Energy	546	59
8	Miscellaneous Other Power Generation Expenses	Sempra Energy	549	116
9	Maintenance of Other Power Generation Expenses	Sempra Energy	554	548
10	System Control and Load Dispatching	Sempra Energy	556	83
11	Other Expenses	Sempra Energy	557	1,159
12	Transmission Operation Supv & Engineering	Sempra Energy	560	4,342
13	Load Dispatch	Sempra Energy	561	1,896
14	Station Expenses	Sempra Energy	562	591
15	Overhead Line Expense	Sempra Energy	563	350
16	Miscellaneous Transmission Expenses	Sempra Energy	566	159,768
17	Maintenance of Structures	Sempra Energy	569	7,475
18	Maintenance of Station Equipment	Sempra Energy	570	1,387
19	Maintenance of Overhead Lines	Sempra Energy	571	1,970
20	**Non-power Goods or Services Provided for Affiliate**			
21	Fleet Services	Southern California Gas Company	146	810,332
22	Human Resources	Southern California Gas Company	146	179,690
23	Information Technology	Southern California Gas Company	146	80,757,741
24	Real Estate & Facilities	Southern California Gas Company	146	1,889,060
25	Supply Management	Southern California Gas Company	146	1,924,530
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42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Operation and Supervision Engineering	Sempra Energy	580	47,146
3	Load Dispatching	Sempra Energy	581	2,503
4	Underground Line Expenses	Sempra Energy	584	57

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)
5	Meter Expenses	Sempra Energy	586	7,312
6	Customer Installations Expenses	Sempra Energy	587	140
7	Miscellaneous Distribution Expenses	Sempra Energy	588	752,587
8	Rents	Sempra Energy	589	2
9	Maintenance Supervision and Engineering	Sempra Energy	590	1,229
10	Maintenance of Station Equipment	Sempra Energy	592	20
11	Maintenance of Overhead Lines	Sempra Energy	593	6,516
12	Maintenance of Meters	Sempra Energy	597	646
13	Maintenance of Misc Distribution Plant	Sempra Energy	598	1
14	Operation Supervision and Engineering	Sempra Energy	850	873
15	Communication System Expenses	Sempra Energy	853	101
16	Mains Expenses	Sempra Energy	856	156
17	Maintenance of Mains	Sempra Energy	863	806
18	Maintenance of Measuring and Regulating Station Eq	Sempra Energy	865	42
19	Operation and Supervision Engineering	Sempra Energy	870	13,152
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
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42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Mains and Services Expenses	Sempra Energy	874	8,048
3	Measuring and Regulating Station Expenses-General	Sempra Energy	875	208
4	Customer Installations Expenses	Sempra Energy	879	21,888
5	Distribution Other Expenses	Sempra Energy	880	15,913
6	Maintenance of Mains	Sempra Energy	887	2,635

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7	Meter Reading Expenses	Sempra Energy	902	3,340
8	Customer Records and Collection Expenses	Sempra Energy	903	17,264
9	Customer Assistance Expenses	Sempra Energy	908	18,769
10	Miscellaneous Customer Service and Info Exp	Sempra Energy	910	335,464
11	Administrative and General Salaries	Sempra Energy	920	3,273,874
12	Office Supplies and Expenses	Sempra Energy	921	168,245
13	Outside Services Employed	Sempra Energy	923	49,461,266
14	Property Insurance	Sempra Energy	924	270,090
15	Injuries and Damages	Sempra Energy	925	25,592,783
16	Employee Pension and Benefits	Sempra Energy	926	54,742,856
17	Regulatory Commission Expenses	Sempra Energy	928	1,100,345
18	Miscellaneous General Expense	Sempra Energy	930	218,831
19	Maintenance of General Plant	Sempra Energy	935	9,311
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Purchased Power	Energia Sierra Juarez	555	42,319,212
3	Construction Work in Progress	Southern California Gas Company	107	7,095,785
4	Other Utility Plant	Southern California Gas Company	118	3,532,764
5	Other Accounts Receivable	Southern California Gas Company	143	1,124
6	Stores Expense Undistributed	Southern California Gas Company	163	715,523
7	Clearing Accounts	Southern California Gas Company	184	3,184,257
8	Accounts Payable	Southern California Gas Company	232	3,559

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Expend for Civic and Political Activities	Southern California Gas Company	426.4	166
10	Miscellaneous Transmission Expenses	Southern California Gas Company	566	2,419
11	Miscellaneous Distribution Expenses	Southern California Gas Company	588	24,895
12	Operation Supervision and Engineering	Southern California Gas Company	850	2,588,029
13	System Control and Load Dispatching	Southern California Gas Company	851	783,021
14	Communication System Expenses	Southern California Gas Company	853	2,698
15	Other Expenses	Southern California Gas Company	859	37,975
16	Maintenance of Mains	Southern California Gas Company	863	194,520
17	Operation Supervision and Engineering	Southern California Gas Company	870	4,227,024
18	Mains and Services Expenses	Southern California Gas Company	874	59,804
19	Distribution Other Expenses	Southern California Gas Company	880	153,874
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 Mains	Southern California Gas Company	887	60,830
3	Maintenance of Meters and House Regulators	Southern California Gas Company	893	258,076
4	Meter Reading Expenses	Southern California Gas Company	902	93,632
5	Customer Records and Collection Expenses	Southern California Gas Company	903	2,669,861
6	Customer Assistance Expenses	Southern California Gas Company	908	786,641
7	Miscellaneous Customer Service and Info Exp	Southern California Gas Company	910	379,596
8	Outside Services Employed	Southern California Gas Company	923	56,142,273
9	Injuries and Damages	Southern California Gas Company	925	433,987
10	Employee Pensions and Benefits	Southern California Gas Company	926	70,156

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	2,042,365
12	Miscellaneous General Expense	Southern California Gas Company	930	180,530
13	Rents	Southern California Gas Company	931	1,154,697
14	Maintenance of General Plant	Southern California Gas Company	935	726,290
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20	**Non-power Goods or Services Provided for Affiliate**			
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[1] (Rows 1-104)
All non-power goods and services provided by affiliated companies are billed to San Diego Gas & Electric at fully loaded cost.

(Rows 2-73)
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 basic without ONCOR, 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 (EXCLUDES ONCOR); 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 & Electric, and between Global Business Units; Multi-factor split without ONCOR, 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 & Electric, and between Global Business Units(EXCLUDES ONCOR); 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 - Vice President of Audit Services, this method is a weighted average of annual labor budget for departments that report to the VP of Audit Services; Average - Vice President of Corporate Development & Technology, this method is a weighted average of annual labor budget for departments that report to the Vice President of Corporate Development & Technology; Average - Vice President of Corporate Communications and Sustainability, this method is a weighted average of annual labor budget for the departments that report to the Vice President of Corporate Communications and Sustainability; 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 at Sempra Energy Corporate Center; 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 & Electric), direct restricted stock and stock options expense for San Diego Gas & 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; 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; 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 rate; 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 multi-factors; Causal - Sacramento Office Depreciation, Needs to be allocated by this method, San Diego Gas & Electric 50%, other affiliates 50%; 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 - Security Services, this method accounts for the call-in transportation services available to Corporate Officers and Executives. These call-in services are primarily provided to Corporate Officers and Executives at the California Utilities and for Mexico and South America. Occasionally, these services may be provided to Officers and Executives in other business units or at Sempra Energy Corporate Center. In this instance, these costs will be directly charged to the respective business unit or retained at Sempra Energy Corporate Center; Causal - Security Headquarters and Mission CSOC Depreciation, Need to be allocated by this method, San Diego Gas & Electric 84.3% other affiliates 15.7%; Causal - Major Projects and 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 - Major Projects Depreciation, needs to be allocated by this method. San Diego Gas & Electric 16% other affiliates 84%; Causal - My Info Services Contract, My Info services cost is allocated by the number of people in the My Info 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; Causal - Pension, this method allocates based on the summary value of Sempra Energy'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 work load hours are re-allocated using Multi-factor (basic) resulting in a blended percentage; 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 - 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 - SOX, this allocation is a weighted average of the workload of each employee within SOX Compliance based on an annual time study. Sempra Energy Corporate Center 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 legal database during the previous August-July period. Hours for Sempra Energy Corporate Center are re-allocated by Multi-Factor Basic, resulting 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 that 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 - Treasury Management System, Needs to be allocated by this method, San Diego Gas & Electric 21.1%, other affiliates 78.9%; Causal - Hyperion Financial Management and Consolidation System, this allocation is a weighted average of the headcount of Hyperion Financial Management and Consolidation System users. The Sempra Energy Corporate Center amount is then re-allocated by Multi-factor (basic) to result in a blended percentage for each business unit; Causal - Bank Reconciliations and Escheatment, for the Bank Reconciliation and Escheatment department, the estimated percentages of effort for the business units based on the bank reconciliation and escheatment activity for the upcoming period; Causal - Cash Management, for the Cash Management department, the Director estimates percentages based on volumes and time involved in the business units funding activities.

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(Rows 75-104)

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 131 Southern California Gas Company cost centers. The following causal beneficial relationship information is a summary of the 24 varying methodologies used: 24 cost centers used a ratio for miles of pipe installed and/or current year by service territory allocations; 19 cost centers used a form of LAN ID counts to determine the shared allocation; 14 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 12 cost centers used a form of departmental studies based on current year budgeted activities and/or dollars; 10 cost centers used a ratio of gas meter counts and service territory allocations; 9 cost centers used a form of allocation of computer and/or server system and resource usage statistics; 7 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; 6 cost centers used a method involving the number of Full Time Equivalent employees benefited by department activity; 5 cost centers used a form of Full Time Equivalent employee statistics for support; 4 cost centers used a form of a workload distribution study for the current year; 3 cost centers used a study based on cases worked by both regulated and non-regulated companies; 3 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 Equivalent employee numbers; 2 cost centers used a form of an allocation of space study identifying building square footage assigned; 2 cost centers used a form of a ratio of horsepower in compressor engines in the service territory; 2 cost centers used a form of a count of network sites; also there was one use by a cost center of each of the remaining allocation methodologies: an allocation using number of stakeholders at each utility; an internal department study based on volumes of items mailed and payments processed and the allocation of employee time; a forecast of total miles of pipe within specific budgeted activity; a form of an allocation based on the weighted average of total utility gas revenue; a form of the number of purchase contracts supported; a summary of legal cases handled within a five-year period with emphasis on expected cases to be worked in and current year; a ratio of miles of pipe and miles of wires installed and/or existing by service territory allocations; a form of ratio by call volume handled coming from a service territory; and, a report of vehicles in-service weighted toward cost impacts of those most recently used.

[2] (Row 105-132)
All non-power goods and services provided by San Diego Gas & Electric are billed at fully loaded cost.

(Row 105)
Affiliate companies charged by San Diego Gas & Electric for less than $250,000 include: Sempra LNG, Sempra International South America, Sempra International Mexico, US Gas and Power Renewables.

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[3] (Rows 106-132)
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 & 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 105 San Diego Gas & Electric cost centers. The following causal-beneficial relationship information is a summary of the 17 varying methodologies used: 25 cost centers used a form of LAN ID counts to determine the shared allocation; 24 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department; 12 cost centers used a form of prior year project assignments as a base for the current year distribution, which is adjusted as necessary when current year projects begin or change and impact the current allocation; 10 cost centers used a form of a workload distribution study for the current year; 6 cost centers used a form of an allocation of space study identifying building square footage assigned; 5 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 Equivalent employee numbers; 5 cost centers used a form of allocation of computer and/or server system and resource usage statistics; 4 cost centers used a form of departmental studies based on current year budgeted activities and/or dollars; 3 cost centers used a form of a count of network sites; 2 cost centers fully support Sempra Energy Corporate Center and were 100% allocated; 2 cost centers used a method involving the number of Full Time Equivalent employees benefited by department activity; 2 cost centers used a form of SAP ID counts to determine the shared allocation; also there was one use by a cost center of each of the remaining allocation methodologies: a form of the number of purchase contracts supported; a form of Full Time Equivalent employee statistics for support; a study based on cases worked by both regulated and non-regulated companies; a form of ratio by call volume handled coming from a service territory; and, number of user licenses available.

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