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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2020/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: https://forms.ferc.gov/. 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 https://www.ferc.gov/ferc-online/overview.

(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 https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

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 2020/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) [X] An Original (2) [ ] A Resubmission	04/16/2021

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)*
Valerie Bille	Valerie Bille	04/16/2021
02 Title VP, Controller and CAO		

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

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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.

Valerie Bille, Vice President, Controller, and Chief Accounting Officer

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

California, April 6, 1905

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

Not Applicable

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

Electric and Natural Gas Services
State of California

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

CONTROL OVER RESPONDENT

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	04/16/2021	End of 2020/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 (2)(9)	Sagara, Kevin C.	562,000
2	Chief Executive Officer (3)	Winn, Caroline A.	562,000
3	President (4)(9)	Drury, Scott D.	532,000
4	President and Chief Financial Officer (5)	Folkmann, Bruce A.	450,000
5	Chief Operating Officer (6)(9)	Winn, Caroline A.	463,100
6	Chief Operating Officer (7)(9)	Geier, David L.	400,000
7	Vice President, Chief Accounting Officer, Treasurer and	Bille, Valerie A.	235,300
8	Controller (8)		
9	Senior Vice President, General Counsel and	Day, Diana L.	356,000
10	Chief Risk Officer		
11	Corporate Secretary	Robinson, April R.	250,020
12			
13	(1) Does not include bonuses and other forms of		
14	compensation.		
15			
16	(2) Resigned 06/26/2020		
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18	(3) Appointed Chief Executive Officer 08/01/2020		
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20	(4) Resigned 07/31/2020		
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22	(5) Appointed President 08/01/2020		
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24	(6) Resigned as Chief Operating Officer 07/31/2020		
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26	(7) Appointed 08/01/2020		
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28	(8) Appointed 8/22/2020		
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30	(9) Salary as of date employment in role terminated		
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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	04/16/2021	End of 2020/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	Kevin C. Sagara, Director and non-executive Chairman (1)	San Diego, CA
2	Robert J. Borthwick, Director (1)	San Diego, CA
3	Erbin B. Keith, Director (1)	San Diego, CA
4	Trevor I. Mihalik, Director (1)	San Diego, CA
5	Caroline A. Winn, Director (2) and Chief Executive Officer	San Diego, CA
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7	(1) Do not hold any offices with SDG&E but are officers of	
8	SDG&E's ultimate parent, Sempra Energy.	
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10	(2) Appoined as director 08/01/2020	
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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	ER20-524-000
3		
4		
5	FERC Electric Tariff, Volume No.11	ER20-503-000
6		
7	FERC Electric Tariff, Volume No.11	ER20-556-000
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10	FERC Electric Tariff, Volume No.11	ER20-563-000
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13	FERC Electric Tariff, Volume No.11	ER20-209-000
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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	04/16/2021	End of 2020/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	20191205-5020	12/05/2019	ER20-524-000	2020 Transmission Revenue Balancing	FERC Electric Tariff, Volume No.11
3				("TRBAA") Filing	
4					
5	20191202-5148	12/02/2019	ER20-503-000	TO5 Cycle 2 Formula Rate Tariff Filing	FERC Electric Tariff, Volume No.11
6					
7	20191210-5113	12/10/2019	ER20-556-000	2020 Transmission Access Charge	FERC Electric Tariff, Volume No.11
8				Adjustment ("TACBAA") Filing	
9					
10	20191211-5096	12/11/2019	ER20-563-000	2020 Reliability Service Balancing	FERC Electric Tariff, Volume No.11
11				("RSBA") Filing	
12					
13	20191028-5141	10/28/2019	ER20-209-000	Appendix XII Cycle 2 Formula Rate	FERC Electric Tariff, Volume No.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	04/16/2021	End of 2020/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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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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. In December 2020, the City of San Diego and SDG&E agreed to extend the natural gas and electric franchises until 06/01/2021. The extension is intended to provide newly elected City officials time to seek public input and additional information.

2. None

3. None

4. SDG&E extended the term of its Right of Entry Agreement for space located at 1010 Tavern Road, Alpine, CA on 10/21/2020. New term extends from 01/01/2021-12/31/2021. Vacated property located at 6955 Consolidated Way, San Diego, CA and lease expired effective 11/30/2020.

5. In the first quarter of 2020, notable changes to the Transmission System included:
TL23056 (SUNCREST - SCR SVC) - newly add 0.40 miles
TL600 (CLAIREMONT - KEARNY WEST - ROSE CANYON) - add new pole and underground conversion to new substation 0.02 miles
TL672 (MESA HEIGHTS - KYOCERA - KEARNY WEST) - add new pole and underground conversion to new substation 0.07 miles
TL6910 (SALT CREEK - BORDER) - Otay Mesa/Alta Road widening project 5.95 miles
TL6901 retired from service 0.04 miles
TL6902 retired from service 0.69 miles
TL6909 retired from service 0.53 miles

   In the second quarter of 2020, notable changes to the Transmission System included:
TL6906 Mesa rim looped in
TL23075 New tie line energized
TL625 Wood to steel and conductor type change
TL99922 De-energized segment of TL633
TL649 Wood to steel and conductor type change
TL99906 Removed from service
TL99923 De-energized segment of TL626

   In the third quarter of 2020, notable changes to the Transmission System included:
TL6912 Remove conductor 1-1033.5 ACSR/AW
TL677 Replace conductor 1-3000 KCMIL CU with 1-1750 KCMIL AL
TL6978 Replace conductor 1-1750 KCMIL AL with 1-3000 KCMIL CU
TL6917 Replace conductor 1-1750 KCMIL AL with 1-3000 KCMIL CU
TL629 Replace conductor 1-1/0 4/3 AWAC with 1-636-24/7 ACSS/AW
TL99921 De-energized segment of TL663. Remove conductor 1-1033.5 ACSR/AW. 1-1750 KCMIL AL. 1-336.4ACSR/AW

   In the fourth quarter of 2020, notable changes to the Transmission System included:
TL672 MSH Rack to Z293559 conductor change from 1-1750 MCM AL to 1-3000 KCMIL CU
Distance change from MSH rack to Z293559 from 150 to 196
TL648 Temporary shoot-fly at RCL Sub.Conductor change from 1-1750 KCMIL AL to 1-1033.5 ACSR/AW
TL6949 New conductor 1-1033.5 ACSR/AW added between two new steel poles Z1937173219 and Z234027

   There were no important changes to the distribution system.

6. During the first quarter of 2020, SDG&E issued commercial paper with an average daily balance of $171.4 million and a maximum outstanding balance of $262.5 million. The quarter-end balance was $0.

   In March 2020, SDG&E borrowed $750 million under its revolving credit facility, maturing 05/17/2024, and repaid $550 million shortly thereafter. As of 03/31/2020, $200 million was outstanding under the revolving credit facility, which is deemed as long-term and recorded to Other Long-Term Debt.

In addition, on 03/19/2020, SDG&E borrowed $200 million under a 364-day term loan, maturing 03/18/2021, which is deemed as short -term and recorded to Notes Payable.

During the second quarter of 2020, SDG&E did not issue commercial paper. The quarter-end balance was $0.

During the second quarter of 2020, SDG&E paid off the $200 million outstanding under its revolving credit facility at 03/31/2020. In addition, on 04/07/2020, SDG&E issued $400 million of 3.32% First Mortgage Bonds maturing 04/15/2050.

During the third quarter of 2020, SDG&E issued commercial paper with an average daily balance of $27.8 million and a maximum outstanding balance of $80.5 million. The quarter-end balance was $0.

On 09/28/2020, SDG&E issued $800 million of 1.70% First Mortgage Bonds, Series VVV, due 10/01/2030.

During the 4th quarter of 2020, San Diego Gas & Electric did not issue commercial paper. The quarter-end balance was $0.

On 12/18/2020, SDG&E redeemed approximately $176 million, prior to a scheduled maturity in 2034, and $75 million, prior to a scheduled maturity in 2039, of tax-exempt industrial development revenue refunding bonds. The redeemed bonds are listed below.

Entity	Bond	Coupon	Maturity	Principal	Redemption Date
SDG&E	Series VV/CV04A	5.875%	02/15/2034	43,615,000	12/18/2020
SDG&E	Series WW/CV04B	5.875%	02/15/2034	40,000,000	12/18/2020
SDG&E	Series XX/CV04C	5.875%	02/15/2034	35,000,000	12/18/2020
SDG&E	Series YY/CV04D	5.875%	01/01/2034	24,000,000	12/18/2020
SDG&E	Series ZZ/CV04E	5.875%	01/01/2034	33,650,000	12/18/2020
SDG&E	Series AAA/CV04F	4.000%	05/01/2039	75,000,000	12/18/2020

7. None

8. In the interest of maintaining adequate staffing levels during the COVID-19 Pandemic, beginning on 03/25/2020, the Company negotiated a series of temporary wage concessions for SDG&E employees represented by the International Brotherhood of Electrical Workers (IBEW) Local 465. The various agreements have temporarily increased the amount of overtime being paid out to employees across the company. The estimated cost of the temporary concessions is $4.8 million.

   On 09/01/2020, SDG&E employees represented by the International Brotherhood of Electrical Workers (IBEW) Local 465 received a negotiated base rate increase of 3.75%, affecting 1419 employees:
   Total annualized base wages for represented employees in 2020 is $15.80 million above 2019 base wages.
   Total annualized wages for represented employees including overtime in 2020 is $15.77 million above 2019 wages including overtime.

9. Please refer to the Legal Proceedings sections of the Notes to the Financial Statements on page 123.66.

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
Cedric Williams	Vice President – Construction	Resigned, 03/20/2020
Paul M. Goldstein	Vice President – Gas Transmission	Appointed, 03/21/2020
Kevin C. Sagara	Chief Executive Officer	Resigned, 06/26/2020
Kevin C. Geraghty	Senior Vice President – Electric Operations	Appointed, 07/01/2020
Scott D. Drury	President	Resigned, 07/31/2020
Valerie A. Bille	Vice President, Chief Accounting Officer, Controller and Treasurer	Appointed, 08/22/2020
Karen L. Sedgwick	Chief Administrative Officer and Chief Human Resources Officer	Resigned, 09/04/2020
Tashonda Taylor	Vice President – Customer Operations	Appointed, 09/05/2020
Neil P. Navin	Vice President – Gas Construction	Resigned, 11/27/2020
Devin K. Zornizer	Vice President – Construction	Appointed, 11/28/2020
Eugene Mitchell	Vice President – State Government Affairs and External Affairs	Resigned, 12/25/2020
Eugene Mitchell	Vice President – External Affairs	Appointed, 12/27/2020
David L. Geier	Chief Operating Officer and Chief Safety Officer	Resigned, 12/31/2020

Changes in Officer Titles:

Name	Title	Effective Date
Neal P. Navin	Vice President – Gas Transmission to Vice President – Gas Construction	Changed, 03/21/2020
Benjamin W. Gordon	Vice President – Technology Operations & Infrastructure Management to Senior Vice President Technology Operations and Infrastructure Management	Changed, 05/16/2020
Caroline A. Winn	Chief Operating Officer to Chief Operating Officer and Chief Safety Officer	Changed, 05/30/2020
Caroline A. Winn	Chief Operating Officer and Chief Safety Officer to Chief Executive Officer	Changed, 08/01/2020

Bruce A. Folkmann	Senior Vice President, Chief Financial Officer, Chief Accounting Officer, Treasurer and Controller to President, Chief Financial Officer, Chief Accounting Officer, Treasurer and Controller	Changed, 08/01/2020
David L. Geier	Senior Vice President - Electric Operations to Chief Operating Officer and Chief Safety Officer	Changed, 08/01/2020
Michael M. Schneider	Vice President - Risk Management and Compliance to Vice President - Risk Management and Compliance and Chief Compliance Officer	Changed, 08/01/2020
Bruce A. Folkmann	President, Chief Financial Officer, Chief Accounting Officer, Treasurer and Controller to President and Chief Financial Officer	Changed, 08/22/2020
Diana L. Day	Vice President, General Council, Chief Risk Officer and Assistant Secretary to Senior Vice President, General Council, Chief Risk Officer and Assistant Secretary	Changed, 08/22/2020
Scott B. Crider	Vice President - Customer Services to Chief Customer Officer	Changed, 09/05/2020
Kendall K. Helm	Vice President - Customer Operations to Vice President - People and Culture	Changed, 09/05/2020
Daniel F. Skopec	from Vice President - Regulatory Affairs to Senior Vice President - State Government Affairs & Chief Regulatory Officer	Changed, 11/28/2020

Changes in Directors:

Name	Title	Effective Date
Kevin C. Sagara	Non-executive Chairman	Changed, 06/26/2020
Caroline A. Winn	Director	Appointed, 08/01/2020

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	04/16/2021	End of 2020/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	22,911,869,746	21,175,191,550
3	Construction Work in Progress (107)	200-201	1,699,907,204	1,500,632,606
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		24,611,776,950	22,675,824,156
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,688,614,673	7,079,972,729
6	Net Utility Plant (Enter Total of line 4 less 5)		16,923,162,277	15,595,851,427
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)		16,923,162,277	15,595,851,427
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,027,761	6,030,598
19	(Less) Accum. Prov. for Depr. and Amort. (122)		326,050	326,050
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	83,449,123	189,218,523
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,018,560,122	1,082,406,303
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		96,188,239	75,216,693
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,203,899,195	1,352,546,067
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		261,589,340	10,497,400
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)		545,017,728	324,851,251
41	Other Accounts Receivable (143)		142,671,640	118,663,035
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		55,474,405	3,956,390
43	Notes Receivable from Associated Companies (145)		0	28,780
44	Accounts Receivable from Assoc. Companies (146)		309,614	198,903
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	141,897,325	131,837,616
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	196,438,887	202,302,974

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		83,449,123	189,218,523
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		371,661	490,246
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		6,960	2,879
57	Prepayments (165)		125,338,625	225,297,312
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		2,463,633	2,424,633
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		83,866,636	76,706,000
62	Miscellaneous Current and Accrued Assets (174)		32,679,971	32,679,971
63	Derivative Instrument Assets (175)		152,068,927	118,060,990
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		96,188,239	75,216,693
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)		1,449,609,680	975,650,884
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		39,351,544	35,819,230
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	2,398,495,226	2,222,440,130
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,338,961	969,994
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)		-195,364	133,106
77	Temporary Facilities (185)		69,702	640,360
78	Miscellaneous Deferred Debits (186)	233	426,356,105	485,680,679
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)		7,746,378	4,654,464
82	Accumulated Deferred Income Taxes (190)	234	108,426,484	143,667,662
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,981,589,036	2,894,005,625
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		22,558,260,188	20,818,054,003

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

The 13-month Average Electric Prepayments for 2020 is $93,697,406.

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

The 13-month Average Electric Prepayments for 2019 is $70,057,189.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	end of 2020/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	802,165,368	802,165,368
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	24,605,640	24,605,640
11	Retained Earnings (215, 215.1, 216)	118-119	6,079,146,682	5,454,653,820
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)	-10,034,102	-15,874,048
16	Total Proprietary Capital (lines 2 through 15)		7,729,413,681	7,099,080,873
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,053,573,000	5,140,552,000
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)		13,172,642	12,166,400
24	Total Long-Term Debt (lines 18 through 23)		6,040,400,358	5,128,385,600
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,324,389,008	1,350,522,358
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		27,160,254	25,612,689
29	Accumulated Provision for Pensions and Benefits (228.3)		98,468,088	157,869,828
30	Accumulated Miscellaneous Operating Provisions (228.4)		-1	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		42,363,865	66,790,512
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		875,839,212	865,801,344
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,368,220,426	2,466,596,731
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		200,000,000	79,768,524
38	Accounts Payable (232)		593,050,722	544,593,815
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		63,664,468	53,342,342
41	Customer Deposits (235)		65,802,220	84,085,883
42	Taxes Accrued (236)	262-263	14,595,365	561,420
43	Interest Accrued (237)		46,363,708	42,855,491
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		9,398,357	5,857,373
48	Miscellaneous Current and Accrued Liabilities (242)		302,751,975	194,863,373
49	Obligations Under Capital Leases-Current (243)		52,796,607	47,248,331
50	Derivative Instrument Liabilities (244)		75,094,995	95,872,552
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		42,363,865	66,790,512
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)		1,381,154,552	1,082,258,592
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		111,420,524	67,517,371
57	Accumulated Deferred Investment Tax Credits (255)	266-267	13,377,869	14,428,349
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	431,442,573	492,083,275
60	Other Regulatory Liabilities (254)	278	2,357,732,274	2,478,762,436
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)		1,834,966,327	1,771,607,192
64	Accum. Deferred Income Taxes-Other (283)		290,131,604	217,333,584
65	Total Deferred Credits (lines 56 through 64)		5,039,071,171	5,041,732,207
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,558,260,188	20,818,054,003

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	5,716,764,976	5,308,696,913		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,237,591,294	3,111,284,012		
5	Maintenance Expenses (402)	320-323	291,139,577	194,086,509		
6	Depreciation Expense (403)	336-337	685,671,419	622,724,838		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	93,924,593	96,619,384		
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)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		3,801,994	2,866,297		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	186,629,503	160,990,560		
15	Income Taxes - Federal (409.1)	262-263	133,332,973	42,623,707		
16	- Other (409.1)	262-263	39,767,865	35,042,898		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	259,864,642	271,389,436		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	229,531,073	169,793,899		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,050,480	-1,194,769		
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)		4,701,158,051	4,366,654,717		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,015,606,925	942,042,196		

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
5,015,890,723	4,644,412,166	697,643,488	662,104,353	3,230,765	2,180,394	2
						3
2,824,080,272	2,705,281,818	416,891,085	408,920,855	-3,380,063	-2,918,661	4
261,193,755	167,050,456	29,945,822	27,036,053			5
603,293,250	547,243,218	78,484,751	72,408,535	3,893,418	3,073,085	6
						7
73,801,234	75,620,668	20,123,359	20,998,716			8
15,744	15,744					9
						10
						11
2,290,749	1,651,351	1,511,245	1,214,946			12
						13
158,923,105	137,773,189	26,784,120	22,493,773	922,278	723,598	14
130,986,812	49,576,298	2,346,161	-6,952,591			15
41,331,754	36,785,557	-1,563,889	-1,742,659			16
237,832,617	245,194,856	22,032,025	26,194,580			17
210,267,707	160,779,928	19,263,366	9,013,971			18
215,516	-986,264	-1,265,996	-208,505			19
						20
						21
						22
						23
						24
4,123,697,101	3,804,426,963	576,025,317	561,349,732	1,435,633	878,022	25
892,193,622	839,985,203	121,618,171	100,754,621	1,795,132	1,302,372	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	04/16/2021	End of 2020/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)		1,015,606,925	942,042,196		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		6,934,453	7,541,623		
35	Nonoperating Rental Income (418)		38,948	31,727		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		13,668,960	28,026,149		
38	Allowance for Other Funds Used During Construction (419.1)		79,095,805	57,453,742		
39	Miscellaneous Nonoperating Income (421)		411,200	626,789		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		86,280,460	78,596,784		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		250,048	250,048		
45	Donations (426.1)		13,530,965	13,057,930		
46	Life Insurance (426.2)		-7,555,514	-6,732,058		
47	Penalties (426.3)		5,587,200	36,409		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		7,169,979	3,322,364		
49	Other Deductions (426.5)		39,572,224	24,034,646		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		58,554,902	33,969,339		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	766,762	738,412		
53	Income Taxes-Federal (409.2)	262-263	-12,613,256	-8,389,469		
54	Income Taxes-Other (409.2)	262-263	-5,822,969	-3,883,973		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	7,765,578	8,089,310		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,315,333	3,199,039		
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)		-11,219,218	-6,644,759		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		38,944,776	51,272,204		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		233,778,584	213,846,544		
63	Amort. of Debt Disc. and Expense (428)		4,107,085	3,709,481		
64	Amortization of Loss on Reaquired Debt (428.1)		1,449,784	1,831,091		
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)		15,223,253	24,531,380		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		24,499,867	19,787,739		
70	Net Interest Charges (Total of lines 62 thru 69)		230,058,839	224,130,757		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		824,492,862	769,183,643		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		824,492,862	769,183,643		

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	$ (4,953,159)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	8,183,923
	$ 3,230,765

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

Eliminates interdepartmental transfers	$ (4,204,395)
Citizens Energy Corporation Sunrise Powerlink Lease Recoveries	6,384,789
	$ 2,180,394

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	$ (4,953,158)
Citizens Energy Corporation Operating Expenses	1,573,097
	$ (3,380,063)

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

Eliminates interdepartmental transfers	$ (2,204,396)
Citizens Energy Corporation Operating Expenses	1,285,735
	$ (2,918,661)

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	1,056,459
	$ 3,893,419

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

Depreciation expenses related to the Citizens Energy Corporation lease	$ 2,836,960
Other	236,124
	$ 3,073,085

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

Citizens Energy Corporation Property Tax	$ 893,770
Citizens Energy Corporation Payroll Tax	28,508
	$ 922,278

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

Citizens Energy Corporation Property Tax	$ 699,382
Citizens Energy Corporation Payroll Tax	24,215
	$ 723,598

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 $166.0 million. There was no short-term debt included in the calculation of the AFUDC in 2020.

In addition, SDGE received approval for an additional waiver relating to AFUDC.

Specifically, SDG&E proposed to first apply existing waivers previously granted by the Commission to its average short-term debt balances to arrive at a net average short-term debt balance. Next, SDG&E proposes to compare the net average short-term debt balance to an established floor of $15.2 million. If the net average short-term debt balance is less than $15.2 million, SDG&E proposes to include the net average short-term debt balance in the calculation of its AFUDC rate. If the net average short-term debt balance exceeds the $15.2 million floor and SDG&E is also holding cash and cash equivalents equal to or greater than that excess, SDG&E proposes to include the established floor of $15.2 million of short-term debt balance in the calculation of its AFUDC rate. There was no impact due to this waiver.

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 $72.7 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $21.8 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 $166.0 million. There was no short-term debt included in the calculation of the AFUDC in 2020.

In addition, SDGE received approval for an additional waiver relating to AFUDC. Specifically, SDG&E proposed to first apply existing waivers previously granted by the Commission to its average short-term debt balances to arrive at a net average short-term debt balance. Next, SDG&E proposes to compare the net average short-term debt balance to an established floor of $15.2 million. If the net average short-term debt balance is less than $15.2 million, SDG&E proposes to include the net average short-term debt balance in the calculation of its AFUDC rate. If the net average short-term debt balance exceeds the $15.2 million floor and SDG&E is also holding cash and cash equivalents equal to or greater than that excess, SDG&E proposes to include the established floor of $15.2 million of short-term debt balance in the calculation of its AFUDC rate. There was no impact due to this waiver.

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 $72.7 million. The average amount of short-term debt included in the calculation of the AFUDC rate is $21.8 million.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		5,454,653,820	4,683,700,304
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	ASU 2018-02 Stranded Tax Effects			1,769,873
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			1,769,873
16	Balance Transferred from Income (Account 433 less Account 418.1)		824,492,862	769,183,643
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			-200,000,000	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-200,000,000	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		6,079,146,682	5,454,653,820
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		6,079,146,682	5,454,653,820
	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	04/16/2021	End of 2020/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)	824,492,862	769,183,643
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	685,671,419	622,724,838
5	Amortization of Unrecovered Plant and Regulatory Study Costs	93,940,337	96,635,128
6	Impairment - Disallowed Costs from 2019 GRC FD	1,058,143	6,320,399
7			
8	Deferred Income Taxes (Net)	36,783,811	106,485,809
9	Investment Tax Credit Adjustment (Net)	-1,050,480	-1,194,769
10	Net (Increase) Decrease in Receivables	-199,928,414	-41,894,139
11	Net (Increase) Decrease in Inventory	-9,945,205	4,240,410
12	Net (Increase) Decrease in Allowances Inventory	-2,970,245	-45,587,670
13	Net Increase (Decrease) in Payables and Accrued Expenses	9,766,905	51,276,102
14	Net (Increase) Decrease in Other Regulatory Assets	-93,977,578	-446,450,613
15	Net Increase (Decrease) in Other Regulatory Liabilities	-83,037,378	322,504,043
16	(Less) Allowance for Other Funds Used During Construction	79,095,805	57,453,742
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: Net (Increase) Decrease in Prepayments and Other	94,119,506	-184,920,300
19	Net Increase (Decrease) in Accrued Interest and Taxes	21,778,194	254,408
20	Wildfire Fund		-322,500,000
21	Other - Net	21,910,750	147,609,767
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,319,516,822	1,027,233,314
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,020,997,426	-1,579,052,227
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	-79,095,805	-57,453,742
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,941,901,621	-1,521,598,485
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	28,790	598,033
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	COLI - Corporate Owned Life Insurance	7,915,112	7,052,078
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	-1,439,145,269	-913,881,645
54	Decommissioning Trust Fund Sales	1,439,145,269	913,881,645
55	Increase (Decrease) in Customer Advances for Construction	44,858,361	19,140,928
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,889,099,358	-1,494,807,446
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,398,076,000	399,580,000
62	Preferred Stock		
63	Common Stock		
64	Other: LTD Issuance Cost	-10,654,000	-4,344,000
65	Other: Equity Contribution from Sempra Energy		322,500,000
66	Net Increase in Short-Term Debt (c)	200,000,000	-211,202,504
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,587,422,000	506,533,496
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-486,979,000	-35,714,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-79,768,524	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-200,000,000	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	820,674,476	470,819,496
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	251,091,940	3,245,364
87			
88	Cash and Cash Equivalents at Beginning of Period	10,497,900	7,252,536
89			
90	Cash and Cash Equivalents at End of period	261,589,840	10,497,900

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

A. Notes for Statement of Cash Flows:

Supplemental Disclosure of Cash Flow Information:			12/31/2020
Income tax payments, net of refunds			24,583,658
Interest payments, net of amounts capitalized			403,723,189
Reconciliation of Cash and Cash Equivalents at December 31, 2020:			
Account 131	Cash		261,589,340
Account 135	Working Funds		500
Account 136	Temporary Cash Investments		-
		$	**261,589,840**

Supplemental Disclosure of Non-Cash Investing & Financing Activities:		
Increase (Decrease) in finance lease (PPA & Fleet and Other Equipment) obligations for investments in property, plant and equipment	$	30,364,515
Accrued Capital Expenditures	$	199,365,000
Common dividends declared but not paid		-
Increase (Decrease) in ARO for investment in PP&E	$	31,369,571

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, 2020, as filed with the SEC on February 25, 2021. 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 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
- Certain plant in service, accumulated depreciation, and regulatory assets
- Certain pension costs between other income and A&G
- Certain balance sheet treatment for operating lease for U.S. GAAP purposes are reported under Property Under Capital Leases, Amortization and Capital Lease Obligations.
- Certain lease expenses between depreciation, interest expenses, and other line items.

▪Software costs related to cloud computing between prepaid expenses and utility plant.

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 LLC'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 was accounted for as a capital lease under FERC accounting requirements and as a variable interest entity under U.S. GAAP requirements through August 23, 2019.

OMEC LLC PPA

We had an agreement through August 23, 2019 to purchase power generated at OMEC, a 573-megawatt generating facility that began commercial operation in October 2009. We supplied all of the natural gas to fuel the power plant, and we purchased its full electric generation output. The agreement was recorded as a capital lease through August 23rd, 2019 and was removed from the balance sheet upon completion of the contract.

FERC Audit FA19-3-000

In accordance with the FERC Audit Report Docket No. FA19-3-000, SDG&E implemented two recommendations in 2020. Based on the requirements in the Audit Report, the current and comparative years revised amounts for Finding No. 2 - Recommendation 11 and Finding No. 4 - Recommendation 24 were as follows:

FERC Audit Implementation (FA19-3)
Unamortized Line of Credit Fees
Finding No. 2; Recommendation 11

Description	FERC Account	2020 Balance as reflected on Page 110,114,117	2020 Adjustment	Corrected 2020 Balance as reflected on Page 110,114,117	2019 Balance as reflected on Page 110,114,117	2019 Adjustment	Corrected 2019 Balance as reflected on Page 110,114,117
Prepayments	165	As Reported	-	As Reported	225,297,312	(3,238,525)	222,058,787
Miscellaneous deferred debits	186	As Reported	-	As Reported	485,680,679	3,238,525	488,919,204

FERC Audit Implementation (FA19-3)
Unamortized Line of Credit Fees
Finding No. 4; Recommendation 24

Description	FERC Account	2020 Balance as reflected on Page 207	2020 Adjustment	Corrected 2020 Balance as reflected on Page 207	2019 Balance as reflected on Page 206	2019 Adjustment	Corrected 2019 Balance as reflected on Page 206
Miscellaneous equipment	398	As Reported	-	As Reported	65,201,467	(56,477,457)	8,724,010
Installations on customers' premises	371	As Reported	-	As Reported	9,733,226	56,477,457	66,210,683

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES AND OTHER FINANCIAL DATA

BASIS OF PRESENTATION

This is a report of SDG&E's common stock which is wholly owned by Enova, which is a wholly owned subsidiary of Sempra Energy. References in this report to "we," "our," and "us" 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, 2020 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
- 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 NDT and benefit plan trust assets and derivatives. We also measure certain assets at fair value on a non-recurring basis in certain circumstances.

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
- other relevant economic measures

Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and 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, and municipal bonds, primarily in the NDT and benefit plan trusts.

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.

CREDIT LOSSES

We are exposed to credit losses from financial assets measured at amortized cost, including trade and other accounts receivable and amounts due from unconsolidated affiliates.

We regularly monitor and evaluate credit losses and record allowances for expected credit losses, if necessary, for trade and other accounts receivable using a combination of factors, including past-due status based on contractual terms, trends in write-offs, the age of the receivable, historical and industry trends, counterparty creditworthiness, economic conditions and specific events, such as bankruptcies. We write off financial assets measured at amortized cost in the period in which we determine they are not recoverable. We record recoveries of amounts previously written off when it is known that they will be recovered.

In connection with the COVID-19 pandemic, SDG&E has implemented certain measures to assist customers, including suspending service disconnections due to nonpayment for residential and small business customers, waiving late payment fees for business customers, and offering flexible payment plans to customers experiencing difficulty paying their electric or gas bills. As we discuss in Note 4, the CPUC authorized us to track and request recovery of incremental costs, including uncollectible expenses, associated with complying with residential and small business customer protection measures implemented by the CPUC related to the COVID-19 pandemic.

In June 2020, the CPUC issued a decision in a separate proceeding addressing service disconnections that, among other things, allows SDG&E to establish a two-way balancing account to record the uncollectible expenses associated with residential customers' inability to pay their electric or gas bills. This decision also directs us to establish an AMP that provides successfully participating, income-qualified residential customers with relief from outstanding utility bill amounts. Refer to Note 4 for further discussion.

SDG&E has recorded increases in our allowances for expected credit losses as of December 31, 2020 primarily related to expected forgiveness of outstanding utility bill amounts, including increases due to the effect of the COVID-19 pandemic, for residential customers eligible under the AMP. Our businesses will continue to monitor macroeconomic factors and customer payment patterns when evaluating their allowances for credit losses in future reporting periods, which may increase significantly due to the effects of the COVID-19 pandemic or other factors.

We provide below allowances and changes in allowances for credit losses for trade and other accounts receivable. We record changes in the allowances for credit losses related to Accounts Receivable – Trade in regulatory accounts.

TRADE AND OTHER ACCOUNTS RECEIVABLE – ALLOWANCES FOR CREDIT LOSSES
(Dollars in millions)

	Years ended December 31,		
	2020	2019	2018
Allowances for credit losses at January 1	$ 14	$ 11	$ 9
Provisions for expected credit losses	65	10	9
Write-offs	(10)	(7)	(7)
Allowances for credit losses at December 31[(1)]	$ 69	$ 14	$ 11

(1) *Balances at December 31, 2020 and 2019 include $55 million and $4 million, respectively, in Accounts Receivable – Trade, Net and $14 million and $10 million, respectively, in Accounts Receivable – Other, Net.*

CONCENTRATION OF CREDIT RISK

Credit risk is the risk of loss that would be incurred as a result of nonperformance by our counterparties on their contractual obligations. We have policies governing the management of credit risk that are administered by our credit department and overseen by our separate risk management committee.

This oversight includes calculating current and potential credit risk on a regular basis and monitoring actual balances in comparison to approved limits. We establish credit limits based on risk and return considerations under terms customarily available in the industry. We avoid concentration of counterparties whenever possible, and we believe our credit policies significantly reduce overall credit risk. These policies include an evaluation of:

- prospective counterparties' financial condition (including credit ratings)
- collateral requirements
- the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty
- downgrade triggers

We believe that we have provided adequate reserves for counterparty nonperformance in our allowances for credit losses.

When our development projects become operational, we rely significantly on the ability of suppliers to perform under long-term agreements and on our ability to enforce contract terms in the event of nonperformance. Also, the factors that we consider in evaluating a development project include negotiating customer and supplier agreements and, therefore, we rely on these agreements for future performance. We also may condition our decision to go forward on development projects on first obtaining these customer and supplier agreements.

INVENTORIES

SDG&E values natural gas inventory using the last-in first-out method. As inventories are sold, differences between the last-in first-out 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	
2020	2019	2020	2019	2020	2019
$ —	$ 1	$ 104	$ 93	$ 104	$ 94

WILDFIRE FUND

In July 2019, the Wildfire Legislation was signed into law. The Wildfire Legislation addresses certain issues related to catastrophic wildfires in the State of California and their impact on electric IOUs. The issues addressed include wildfire mitigation, cost recovery standards and requirements, a wildfire fund, a cap on liability, and the establishment of a wildfire safety board.

The Wildfire Legislation provided that SDG&E would not recover the ROE on its first $215 million of fire risk mitigation capital expenditures.

The Wildfire Legislation established a revised legal standard for the recovery of wildfire costs (Revised Prudent Manager Standard) and established a fund (the Wildfire Fund) designed to provide liquidity to SDG&E, PG&E and Edison to pay IOU wildfire-related claims in the event that the governmental agency responsible for determining causation determines the applicable IOU's equipment caused the ignition of a wildfire, primary insurance coverage is exceeded and certain other conditions are satisfied. A primary purpose of the Wildfire Fund is to pool resources provided by shareholders and ratepayers of the IOUs and make those resources available to reimburse the IOUs for third-party wildfire claims incurred after July 12, 2019, the effective date of the Wildfire Legislation, subject to certain limitations.

An IOU may seek payment from the Wildfire Fund for settled or adjudicated third-party damage claims arising from certain wildfires that exceed, in aggregate in a calendar year, the greater of $1 billion or the IOU's required amount of insurance coverage as recommended by the Wildfire Fund's administrator. Wildfire claims approved by the Wildfire Fund's administrator will be paid by the Wildfire Fund to the IOU to the extent funds are available. These utilized funds will be subject to review by the CPUC, which will make a determination as to the degree an IOU's conduct related to an ignition of a wildfire was prudent or imprudent. The Revised Prudent Manager Standard requires that the CPUC apply clear standards when reviewing wildfire liability losses paid when determining the reasonableness of an IOU's conduct related to an ignition. Under this standard, the conduct under review related to the ignition may include factors within and beyond the IOU's control, including humidity, temperature and winds. Costs and expenses may be allocated for cost recovery in full or in part. Also, under this standard, an IOU's conduct will be deemed reasonable if a valid annual safety certification is in place at the time of the ignition, unless a serious doubt is raised, in which case the burden shifts to the utility to dispel that doubt. The IOUs will receive an annual safety certification from the CPUC if they meet various requirements.

If an IOU has maintained a valid annual safety certification, to the extent it is found to be imprudent, claims will be reimbursable by the IOU to the Wildfire Fund up to a cap based on the IOU's rate base. The aggregate requirement to reimburse the Wildfire Fund over a trailing three calendar year period is capped at 20% of the equity portion of an IOU's electric transmission and distribution rate base in the year of the prudency determination. Based on its 2020 rate base, the liability cap for SDG&E is approximately $950 million, which is adjusted annually. The liability cap will apply on a rolling three-year basis so long as future annual safety certifications are received and the Wildfire Fund has not been terminated, which could occur if funds are exhausted. Amounts in excess of the liability cap and amounts that are determined to be prudently incurred do not need to be reimbursed by an IOU to the Wildfire Fund. The Wildfire Fund does not have a specified term and coverage will continue until the assets of the Wildfire Fund are exhausted and the Wildfire Fund is terminated, in which case, the remaining funds, if any, will be transferred to California's general fund to be used for fire risk mitigation programs.

In June 2020, the CPUC approved SDG&E's 2020 wildfire mitigation plan, which is effective until the CPUC approves a new plan. In addition, on September 14, 2020, SDG&E received its 2020 safety certification from the Wildfire Safety Division of the CPUC. The certificate is valid for 12 months from the issue date.

The Wildfire Fund has been initially funded up to $10.5 billion by a loan from the State of California Surplus Money Investment Fund. The loan is financed through a DWR bond, which was put in place on October 1, 2020 and is securitized through a dedicated surcharge on ratepayers' bills attributable to the DWR. In October 2019, the CPUC adopted a decision authorizing a non-bypassable charge to be collected by the IOUs to support the anticipated DWR bond issuance authorized by AB 1054. The CPUC decision also determined that ratepayers of non-participating electrical corporations shall not pay the non-bypassable charge.

The Wildfire Fund has also been funded $7.5 billion from initial shareholder contributions from the IOUs (SDG&E's share was $322.5 million, PG&E's share was $4.8 billion and Edison's share was $2.4 billion). The IOUs are also required to make annual shareholder contributions to the Wildfire Fund with an aggregate value of $3 billion over a 10-year period starting in 2019 (SDG&E’s share is $129 million, PG&E’s share is $1.9 billion and Edison’s share is $945 million). The contributions are not subject to rate recovery.

In a complaint filed in U.S. District Court for the Northern District of California in July 2019, plaintiffs seek to invalidate AB 1054 based on allegations that the legislation violates federal law. That court dismissed the complaint and the plaintiffs have petitioned the U.S. Court of Appeals for the Ninth Circuit to review the dismissal.

Wildfire Fund Asset and Obligation

In the third quarter of 2019, SDG&E recorded both a Wildfire Fund asset and a related obligation of $451.5 million for its commitment to make shareholder contributions to the Wildfire Fund, measured at present value as of July 25, 2019 (the date by which both Edison and SDG&E opted to contribute to the Wildfire Fund). SDG&E paid its initial shareholder contribution of $322.5 million to the Wildfire Fund in September 2019. SDG&E funded this contribution with proceeds from an equity contribution from Sempra Energy. Sempra Energy funded the equity contribution to SDG&E with proceeds from settling forward sale agreements through physical delivery of shares of Sempra Energy common stock in exchange for cash. Edison paid its initial shareholder contribution in September 2019 and PG&E paid its initial shareholder contribution in July 2020 after receiving bankruptcy court approval to participate in the Wildfire Fund. SDG&E expects to make annual shareholder contributions of $12.9 million through December 31, 2028. SDG&E accretes the present value of the Wildfire Fund obligation until the liability is settled.

SDG&E is amortizing the Wildfire Fund asset on a straight-line basis over the estimated period of benefit, as adjusted for utilization by the IOUs. The estimated period of benefit of the Wildfire Fund asset is 15 years and is based on several assumptions, including, but not limited to:

- historical wildfire experience of each IOU in the State of California, including frequency and severity of the wildfires
- the value of property potentially damaged by wildfires
- the effectiveness of wildfire risk mitigation efforts by each IOU
- liability cap of each IOU
- IOU prudency determination levels
- FERC jurisdictional allocation levels
- insurance coverage levels

The use of different assumptions, or changes to the assumptions used, could have a significant impact on the estimated period of benefit of the Wildfire Fund asset. SDG&E periodically evaluates the estimated period of benefit of the Wildfire Fund asset based on actual experience and changes in these assumptions. SDG&E may recognize a reduction of its Wildfire Fund asset and record a charge against earnings in the period when there is a reduction of the available coverage due to recoverable claims from any of the participating IOUs. Wildfire claims that are recoverable from the Wildfire Fund, net of anticipated or actual reimbursement to the Wildfire Fund by the responsible IOU, would decrease the Wildfire Fund asset and remaining available coverage. Although California experienced some of the largest wildfires in its history in 2020 (measured by acres burned), including fires in each participating IOU’s service territory, SDG&E is not aware of any claims made by any participating IOU requiring a reduction of the Wildfire Fund asset as of December 31, 2020.

The following table summarizes the location of balances related to the Wildfire Fund on SDG&E’s Balance Sheet and Statement of Operations.

WILDFIRE FUND
(Dollars in millions)

	Location	December 31, 2020		December 31, 2019	
Wildfire Fund asset:					
Current	Prepaid	$	29	$	29
Noncurrent	Wildfire Fund		363		392
Wildfire Fund obligation:					
Current	Other Current Liabilities	$	13	$	13
Noncurrent	Deferred Credits and Other		75		86

		Years ended December 31, 2020		Years ended December 31, 2019	
Amortization of Wildfire Fund asset	Operation and Maintenance	$	29	$	12
Accretion of Wildfire Fund obligation	Operation and Maintenance		2		1

INCOME TAXES

Income tax expense includes current and deferred income taxes. We record deferred income taxes for temporary differences between the book and the tax basis of assets and liabilities. Investment tax credits 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%. 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% likely of being realized upon its effective resolution.

Unrecognized income 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 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 sheet 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 Program 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 Program. 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 is recorded at cost and primarily represents the buildings, equipment and other facilities used to provide natural gas and electric utility services, including construction work in progress. PP&E also includes lease improvements and other equipment. 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. 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)

	December 31,		Depreciation rates for years ended December 31,		
	2020	2019	2020	2019	2018
Natural gas operations	$ 2,805	$ 2,534	2.51 %	2.47 %	2.44 %
Electric distribution	8,592	7,985	3.90	3.94	3.91
Electric transmission(1)	7,156	6,577	3.10	2.79	2.76
Electric generation	2,440	2,415	4.56	4.50	4.12
Other electric	1,743	1,492	6.92	6.61	6.43
Construction work in progress(1)	1,700	1,501	NA	NA	NA
Total	$ 24,436	$ 22,504			

(1) *At December 31, 2020, includes $505 million in electric transmission assets and $9 million in construction work in progress related to SDG&E's 88% 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 the Statement of Operations.*

Depreciation expense is computed using the straight-line method over the asset's estimated 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,		
2020	2019	2018
$ 779	$ 719	$ 655

ACCUMULATED DEPRECIATION AND AMORTIZATION
(Dollars in millions)

	December 31,	
	2020	2019
Accumulated depreciation:		
Natural gas operations	$ 870	$ 832
Electric transmission, distribution and generation(1)	5,145	4,705
Total	$ 6,015	$ 5,537

(1) *Includes $277 million at December 31, 2020 related to SDG&E's 88% interest in the Southwest Powerlink transmission line, jointly owned by SDG&E and other utilities.*

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

We capitalize interest costs incurred to finance capital projects that have not commenced planned principal operations.

The table below summarizes capitalized interest and AFUDC.

CAPITALIZED FINANCING COSTS
(Dollars in millions)

Years ended December 31,		
2020	2019	2018
$ 104	$ 75	$ 82

We provide additional information about temporary adjustments to the AFUDC rate calculation in relation to the COVID-19 pandemic in Note 4.

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. 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 AROs are as follows:

CHANGES IN ASSET RETIREMENT OBLIGATIONS
(Dollars in millions)

	2020	2019
Balance as of January 1	$ 866	$ 872
Accretion expense	39	39
Liabilities incurred	—	—
Payments	(60)	(44)
Revisions	31	(1)
Balance at December 31	$ 876	$ 866

CONTINGENCIES

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

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

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

LEGAL FEES

Legal fees that are associated with a past event for which a liability has been recorded are accrued when it is probable that fees also will be incurred and amounts are estimable.

COMPREHENSIVE INCOME

Comprehensive income includes all changes in the equity of a business enterprise (except those resulting from investments by owners and distributions to owners), including:

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

The Statement of Comprehensive Income (Loss) shows the changes in the components of OCI, including the amounts attributable to NCI. The following tables present the changes in AOCI by component and amounts reclassified out of AOCI to net income, excluding amounts attributable to NCI:

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

(Dollars in millions)

	Pension and other postretirement benefits	Total accumulated other comprehensive income (loss)
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)**
Adoption of ASU 2018-02	(2)	(2)
OCI before reclassifications	(5)	(5)
Amounts reclassified from AOCI	1	1
Net OCI	(4)	(4)
Balance as of December 31, 2019	**(16)**	**(16)**
OCI before reclassifications[2]	(4)	(4)
Amounts reclassified from AOCI[2]	10	10
Net OCI	6	6
Balance as of December 31, 2020	**$ (10)**	**$ (10)**

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

(2) *Pension and Other Postretirement Benefits and Total AOCI include $6 million in transfers of liabilities from SDG&E to SoCalGas and $3 million in transfers of liabilities from SDG&E to Sempra Energy in 2020 related to the nonqualified pension plans.*

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 Consolidated Statements of Operations
	Years ended December 31,			
	2020	2019	2018	
Pension and other postretirement benefits[1]:				
Amortization of actuarial loss	$ 1	$ —	$ 1	Other Income, Net
Amortization of prior service cost	1	1	—	Other Income, Net
Settlement charges	—	—	4	Other Income, Net
Total before income tax	2	1	5	
	(1)	—	(1)	Income Tax Expense
Net of income tax	$ 1	$ 1	$ 4	
Total reclassifications for the period, net of tax	**$ 1**	**$ 1**	**$ 4**	

(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, insurance, rent and litigation expense.

TRANSACTIONS WITH AFFILIATES

Amounts due from and to unconsolidated affiliates at SDG&E are in the following table.

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

	December 31, 2020	December 31, 2019
Sempra Energy	$ (38)	$ (37)
SoCalGas	(21)	(10)
Various affiliates	(5)	(6)
Total due to unconsolidated affiliates – current	$ (64)	$ (53)
Income taxes due from Sempra Energy[1]	$ —	$ 130

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

The following table summarizes income statement information from unconsolidated affiliates.

INCOME STATEMENT IMPACT FROM UNCONSOLIDATED AFFILIATES
(Dollars in millions)

	Years ended December 31, 2020	2019	2018
Revenue	$ 6	$ 6	$ 5
Cost of Sales	79	74	73

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 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 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 ESJ wind power generation facility. ESJ is a 50% owned and unconsolidated JV of Sempra Mexico.

RESTRICTED NET ASSETS

The CPUC's regulation of our capital structures limits the amounts available for dividends and loans to Sempra Energy. At December 31, 2020, Sempra Energy could have received combined loans and dividends of approximately $717 million from SDG&E.

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

- The CPUC requires that SDG&E's 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, 2020 is 52%.
- SDG&E has a revolving credit line that requires it to maintain a ratio of indebtedness to capitalization (as defined in the agreements) of no more than 65%, as we discuss in Note 5.

Based on these restrictions, at December 31, 2020, SDG&E's restricted net assets were $7.0 billion which could not be transferred to Sempra Energy.

OTHER (EXPENSE) INCOME, NET

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

OTHER (EXPENSE) INCOME, NET
(Dollars in millions)

	Years ended December 31,		
	2020	2019	2018
Allowance for equity funds used during construction	$ 79	$ 56	$ 61
Non-service component of net periodic benefit cost	(20)	(20)	(6)
Fine related to Energy Efficiency Program Inquiry	(6)	—	—
Interest on regulatory balancing accounts, net	9	13	4
Sundry, net	(10)	(10)	(5)
Total	$ 52	$ 39	$ 54

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 2016-13, "Measurement of Credit Losses on Financial Instruments": ASU 2016-13, as amended by subsequently issued ASUs, changes how entities 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 receivables and 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. We adopted the standard on January 1, 2020 using a modified retrospective approach through a cumulative-effect adjustment to retained earnings. There was an insignificant impact to SDG&E's balance sheet from adoption.

ASU 2020-04, "Facilitation of the Effects of Reference Rate Reform on Financial Reporting": ASU 2020-04 provides optional expedients and exceptions for applying U.S. GAAP to contract modifications that replace LIBOR or another reference rate affected by reference rate reform and to hedging relationships that reference LIBOR or another reference rate affected or expected to be affected by reference rate reform. ASU 2020-04 was effective March 12, 2020 and can be applied through December 31, 2022, with certain exceptions for hedging relationships that continue to exist after this date, and may be applied from January 1, 2020. For contract modifications, the standard allows entities to account for modifications as an event that does not require reassessment or remeasurement (i.e., as a continuation of the existing contract). The standard also allows entities to amend their formal designation and documentation of hedging relationships affected or expected to be affected by reference rate reform, without having to de-designate the hedging relationship. Entities may elect the optional expedients and exceptions on an individual hedging relationship basis and independently from one another. We elected the optional expedients for contract modifications. We elected the cash flow hedging expedients to disregard the potential discontinuation of a reference rate when assessing whether a hedged forecasted interest payment is probable and to disregard certain mismatches between the designated hedging instrument and the hedged item when assessing the hedge effectiveness. We are applying these expedients prospectively from January 1, 2020. Application of these expedients preserves the presentation of derivatives consistent with the past presentation.

NOTE 3. REVENUES

The following table disaggregates our revenues from contracts with customers by major service line and market and provides a reconciliation to total revenues by segment. The majority of our revenue is recognized over time.

DISAGGREGATED REVENUES
(Dollars in millions)

	Year ended December 31,		
	2020	2019	2018
By major service line:			
Utilities	$ 4,920	$ 4,820	$ 4,790
Energy-related businesses	—	—	—
Revenues from contracts with customers	$ 4,920	$ 4,820	$ 4,790
By market:			
Gas	$ 692	$ 587	$ 491
Electric	4,228	4,233	4,299
Revenues from contracts with customers	$ 4,920	$ 4,820	$ 4,790
Revenues from contracts with customers	$ 4,920	$ 4,820	$ 4,790
Utilities regulatory revenues	393	106	(220)
Other revenues	—	—	—
Total revenues	$ 5,313	$ 4,926	$ 4,570

REVENUES FROM CONTRACTS WITH CUSTOMERS

Our revenues from contracts with customers are primarily related to the transmission, distribution and storage of natural gas and the generation, transmission and distribution of electricity. 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 we 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 natural gas and electricity as ongoing and integrated services. Generally, natural gas or electricity 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 natural gas or electricity 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.

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 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 their customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SDG&E’s 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.

Revenues

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

Our revenues are derived from and recognized upon the delivery of natural gas or electricity 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 follows 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 reasonable operating costs 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. SDG&E's 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.

In connection with the COVID-19 pandemic, SDG&E and the CPUC have implemented certain measures to assist customers, including suspending service disconnections due to nonpayment for residential and small business customers, waiving late payment fees for business customers, and offering flexible payment plans to customers experiencing difficulty paying their electric or gas bills. Additional measures could be mandated or voluntarily implemented in the future. Under the regulatory compact applicable to us, including decoupling of rates, recovery of uncollectible expenses, and other recovery mechanisms potentially available, which we discuss in Note 4, we have continued to recognize revenues under ASC 606, "Revenue from Contracts with Customers," in the year ended December 31, 2020.

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) variable consideration 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, 2020, we expect to recognize revenue related to the fixed fee component of the consideration as shown below.

REMAINING PERFORMANCE OBLIGATIONS[1] *(Dollars in millions)*		
2021	$	4
2022		4
2023		4
2024		4
2025		4
Thereafter		67
Total revenues to be recognized	$	87

(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.

Activities within SDG&E's contract liabilities are presented below. There were no contract liabilities at SDG&E in 2018.

CONTRACT LIABILITIES *(Dollars in millions)*				
		2020		2019
Contract liabilities at January 1	$	(91)	$	—
Revenue from performance obligations satisfied during reporting period		4		1
Payments received in advance		—		(92)
Contract liabilities at December 31[1]	$	(87)	$	(91)

(1) *Balances at December 31, 2020 and 2019 include $4 million and $4 million, respectively, in Other Current Liabilities and $83 million and $87 million, respectively, in Deferred Credits and Other.*

Receivables from Revenues from Contracts with Customers

The table below shows receivable balances associated with revenues from contracts with customers on the Consolidated Balance Sheets.

RECEIVABLES FROM REVENUES FROM CONTRACTS WITH CUSTOMERS *(Dollars in millions)*				
	December 31,			
		2020		2019
Accounts receivable – trade, net	$	573	$	398
Accounts receivable – other, net		8		5
Due from unconsolidated affiliates – current[1]		2		2

Total	$ 583	$ 405

(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.

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 natural gas and electricity 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 us 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 the SDG&E has earnings potential above authorized base margins if we achieve or exceed specific performance and operating goals. Generally, for performance-based awards, if performance is above or below specific benchmarks, we are 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 and the FERC authorize SDG&E to collect revenue requirements for operating costs and capital related costs (such as depreciation, taxes and return on rate base) from customers, including:

- costs to purchase natural gas and electricity;
- costs associated with administering public purpose, demand response, and customer energy efficiency programs;
- other programmatic activities, such as gas distribution, gas transmission, gas storage integrity management and wildfire mitigation; and
- costs associated with third party liability insurance premiums.

Authorized costs are recovered as the commodity or service is delivered. To the extent authorized amounts collected vary from actual costs, the differences are generally recovered or refunded within a subsequent period based on the nature of the balancing account mechanism. In general, the revenue recognition criteria for balanced costs billed to customers are met at the time the costs are incurred. Because these costs are substantially recovered in rates through a balancing account mechanism, changes in these costs are reflected as changes in revenues. The CPUC and the FERC may impose various review procedures before authorizing recovery or refund for programs authorized, 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.

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, 2020	December 31, 2019
Fixed-price contracts and other derivatives	$ (53)	$ 8
Deferred income taxes recoverable (refundable) in rates	22	(108)
Pension and other postretirement benefit plan obligations	50	103
Removal obligations	(2,121)	(2,056)
Environmental costs	56	45
Sunrise Powerlink fire mitigation	121	121
Regulatory balancing accounts(1)(2)		
Commodity – electric	72	102
Gas transportation	35	22
Safety and reliability	67	77
Public purpose programs	(158)	(124)
2019 GRC retroactive impacts	56	111
Other balancing accounts	233	106
Other regulatory assets (liabilities), net(2)	72	(153)
Total	$ (1,548)	$ (1,746)

(1) *At December 31, 2020 and 2019, the noncurrent portion of regulatory balancing accounts – net undercollected was $139 million and $108 million, respectively.*

(2) *Includes regulatory assets earning a 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.
- 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 and liabilities include excess deferred income taxes resulting from statutory income tax rate changes and certain income tax benefits and expenses associated with flow-through items, which we discuss in Note 6.

- Regulatory assets/liabilities related to pension and other postretirement benefit plan obligations are offset by corresponding liabilities/assets and are being recovered in rates as the plans are funded.
- Regulatory liabilities from removal obligations represent cumulative amounts collected in rates for future asset removal costs in excess of cumulative amounts incurred (or paid).
- Regulatory assets related to environmental costs represent the portion of our environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. We expect this amount to be recovered in future rates as expenditures are made.
- The regulatory asset related to 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 49-year period.
- Over- and undercollected regulatory balancing accounts reflect the difference between customer billings and recorded or CPUC-authorized costs, including commodity costs. Depreciation, taxes 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. The adopted revenue requirements in the 2019 GRC FD associated with the period from January 1, 2019 through December 31, 2019 are being recovered in rates over a 24-month period that began in January 2020.

Amortization expense on regulatory assets for the years ended December 31, 2020, 2019 and 2018 was $4 million, $3 million and $2 million, respectively, at SDG&E.

COVID-19 Pandemic Protections

In March 2020, the CPUC required that all energy companies under its jurisdiction, including SDG&E, take action to implement several emergency customer protection measures to support California customers in light of the COVID-19 pandemic for up to one year. Currently, the customer protection measures are mandatory for all residential and small business customers. In February 2021, the CPUC extended the customer protection measures through June 2021 and may extend them further. SDG&E was authorized to track and request recovery of incremental costs associated with complying with residential and small business customer protection measures implemented by the CPUC related to the COVID-19 pandemic, including costs associated with suspending service disconnections and uncollectible expenses that arise from these customers' failure to pay. We expect to pursue recovery of tracked costs in rates in a future CPUC proceeding, which recovery is not assured.

Disconnection OIR

In June 2020, the CPUC issued a decision to adopt certain customer protections to reduce residential customer disconnections and improve reconnection processes, including, among other things, imposing limitations on service disconnections, elimination of deposit requirements and reconnection fees, establishment of the AMP that provides successfully participating, income-qualified residential customers with relief from outstanding utility bill amounts, and increased outreach and marketing efforts. The decision allows SDG&E to establish a two-way balancing account to record the uncollectible expenses associated with residential customers' inability to pay their electric or gas bills, including as a result of the relief from outstanding utility bill amounts provided under the AMP.

CPUC General Rate Case

The CPUC uses GRC proceedings to set rates designed to allow SDG&E to recover reasonable operating costs and to provide the opportunity to realize our authorized rates of return on our investments.

2019 General Rate Case

In September 2019, the CPUC issued a final decision in the 2019 GRC approving SDG&E's test year revenues for 2019 and attrition year adjustments for 2020 and 2021, which was effective retroactively to January 1, 2019. This is the first GRC that includes revenues authorized for risk assessment mitigation phase activities.

The 2019 GRC FD approved a test year 2019 revenue requirement of $1,990 million for SDG&E's combined operations ($1,590 million for electric operations and $400 million for natural gas operations).

The increases include separately authorized components for O&M and capital-related costs, as follows:

AUTHORIZED REVENUE REQUIREMENT INCREASES FOR 2020 AND 2021
(Dollars in millions)

	2020 increase from 2019		2021 increase from 2020	
	Revenue increase	Percent increase	Revenue increase	Percent increase
O&M	$ 20	2.64 %	$ 19	2.47 %
Capital-related costs	114	9.74	83	6.47
Total increase	$ 134	6.74	$ 102	4.83

In January 2020, the CPUC issued a final decision implementing a four-year GRC cycle for California IOUs. SDG&E was directed to file a petition for modification to revise its 2019 GRC to add two additional attrition years, resulting in a transitional five-year GRC period (2019-2023). We filed the petition in April 2020 and requested authorization of our post-test year ratemaking mechanism for two additional years. We subsequently requested an updated increase in the revenue requirement of approximately $91 million for 2022, and $104 million for 2023, reflecting certain adjustments. These amounts include revenues for both O&M and capital cost attrition. In June 2020, the CPUC issued a ruling to further clarify the issues for review in our petition, which are mainly whether the proposed revenue requirements and mechanisms for the two proposed additional attrition years are just and reasonable. In September 2020, we filed a status report to summarize positions on how impacts of the COVID-19 pandemic should be incorporated into the proposed attrition rates. We proposed to continue with the adopted attrition mechanism using the second quarter 2020 Global Insight utility cost forecast, which incorporates impacts of the COVID-19 pandemic. Intervenors have proposed other alternatives, including using escalation factors based on the Consumer Price Index. We expect a proposed decision in the first quarter of 2021.

The 2019 GRC FD approved the establishment of two-way liability insurance premium balancing accounts, including wildfire insurance premium costs based on a specific level of coverage. The 2019 GRC FD also permits SDG&E to seek recovery of additional liability insurance coverage.

The 2019 GRC FD clarified that differences between incurred and forecasted income tax expense due to forecasting differences are not subject to tracking in the income tax expense memorandum account beginning in 2019. SDG&E previously recorded a regulatory liability, inclusive of interest, associated with the 2016 through 2018 tracked forecasting differences of $86 million. In April 2020, the CPUC confirmed treatment of the two-way income tax expense memorandum account for these 2016 through 2018 balances, at which time we released the regulatory liability balance to revenues and regulatory interest.

CPUC Cost of Capital

In December 2019, the CPUC approved the cost of capital and rate structures (shown in the table below) for SDG&E that became effective on January 1, 2020 and will remain in effect through December 31, 2022. SDG&E did not propose a 2020 cost of preferred equity in this proceeding. In January 2020, SDG&E filed an advice letter to continue the cost of preferred equity for test year 2020 at 6.22%, which the CPUC approved in March 2020.

CPUC AUTHORIZED COST OF CAPITAL AND RATE STRUCTURE

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

The CCM was reauthorized in the 2020 cost of capital proceeding to continue through 2022. SDG&E's CCM benchmark rate is 4.498%, based on Moody's Baa- utility bond index. The index applicable to SDG&E is based on its credit rating. The CCM benchmark rates for SDG&E is the basis of comparison to determine if future measurement periods "trigger" the CCM. For the 12 months ended September 2020, the first "CCM Period," the trigger did not occur for SDG&E. The next CCM Period is from October 2020 to September 2021. The CCM, if triggered in 2021, would be effective January 1, 2022, and would automatically update the authorized cost of debt based on actual costs and update the authorized ROE upward or downward by one-half of the difference between the CCM benchmark and the applicable 12-month average Moody's utility bond index.

FERC Rate Matters and Cost of Capital

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

SDG&E's TO4 ROE of 10.05% was the basis of SDG&E's FERC-related revenue recognition until March 2020, when the FERC approved the settlement terms that SDG&E and all settling parties reached in October 2019 on SDG&E's TO5 filing. The settlement agreement provided for a ROE of 10.60%, consisting of a base ROE of 10.10% plus an additional 50 bps for participation in the California ISO. If the FERC issues an order ruling that California IOUs are no longer eligible for the additional California ISO ROE, SDG&E would refund the additional 50 bps of ROE associated with the California ISO as of the refund effective date (June 1, 2019) in this proceeding. The TO5 term is effective June 1, 2019 and shall remain in effect indefinitely, with parties having the annual right to terminate the agreement beginning in 2022. In 2020, SDG&E recorded retroactive revenues of $12 million related to 2019, and additional FERC revenues of $17 million to conclude a rate base matter, net of certain refunds to be paid to CPUC-jurisdictional customers.

Energy Efficiency Program Inquiry

In January 2020, the CPUC issued a ruling seeking comments on a report prepared by its consultant regarding SDG&E's Upstream Lighting Program for the program year 2017. The CPUC subsequently expanded the scope of the comments to cover the program year 2018. The Upstream Lighting Program was one of SDG&E's Energy Efficiency programs designed to produce energy efficiency savings for which SDG&E could earn a performance-based incentive.

Pursuant to the CPUC ruling, intervenors representing ratepayers have questioned SDG&E's management of the program and alleged that certain program expenditures did not benefit the purpose of the program. As a result of the inquiry, SDG&E voluntarily expanded its review to include the program year 2019. Based on this review and discussions with intervenors, SDG&E concluded that some concessions were appropriate, which include refunding certain costs and certain performance-based incentives to customers and incurring a fine. Accordingly, in the year ended December 31, 2020, SDG&E reduced revenues by $51 million and recorded a fine of $6 million in Other (Expense) Income, Net, on the SDG&E Statement of Operations. The after-tax impact for the year ended December 31, 2020 was $44 million. In October 2020, SDG&E executed a settlement agreement with intervenors consistent with these concessions. We expect CPUC approval of the settlement agreement in 2021.

NOTE 5. DEBT AND CREDIT FACILITIES

LINE OF CREDIT

Committed Line of Credit

At December 31, 2020, SDG&E had a $1.5 billion unused and available committed line of credit, which provides liquidity and supports commercial paper. The facility also provides for issuance of $100 million of letters of credit on behalf of SDG&E with the amount of borrowings otherwise available under the facility reduced by the amount of outstanding letters of credit. Subject to obtaining commitments from existing or new lenders and satisfaction of other specified conditions, SDG&E has the right to increase the letter of credit commitment up to $250 million. No letters of credit were outstanding at December 31, 2020.

The principal terms of the committed line of credit in the table above include the following:

- It is a 5-year syndicated revolving credit agreement expiring in May 2024.
- JPMorgan Chase Bank, N.A. serves as administrative agent for the SDG&E facility.
- The facility has a syndicate of 23 lenders. No single lender has greater than a 6% share in the facility.
- Borrowings bear interest at benchmark rates plus a margin that varies with SDG&E’s credit rating in the case of SDG&E’s line of credit.
- SDG&E must maintain a ratio of indebtedness to total capitalization (as defined in each of the applicable credit facilities) of no more than 65% at the end of each quarter. At December 31, 2020, SDG&E was in compliance with this ratio and all other financial covenants under its credit facility.

TERM LOAN

In March 2020, SDG&E borrowed $200 million under a 364-day term loan, which has a maturity date of March 18, 2021 with an option to extend the maturity date to September 17, 2021, subject to receiving the consent of the lenders. Borrowings bear interest at benchmark rates plus 80 bps (0.95% at December 31, 2020). The term loan provides SDG&E with additional liquidity outside of its committed line of credit. SDG&E classified this term loan as short-term debt based on the term of the loan.

WEIGHTED-AVERAGE INTEREST RATES

The weighted-average interest rates on the total short-term debt were 0.95 percent and 1.97 percent at December 31, 2020 and 2019, respectively.

LONG-TERM DEBT

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

LONG-TERM DEBT AND FINANCE LEASES
(Dollars in millions)

	December 31, 2020	December 31, 2019
First mortgage bonds (collateralized by plant assets):		
3% August 15, 2021	$ 350	$ 350
1.914% payable 2015 through February 2022	53	89
3.6% September 1, 2023	450	450
2.5% May 15, 2026	500	500
6% June 1, 2026	250	250
1.7% October 1, 2030	800	—
5.875% January and February 2034(1)	—	176
5.35% May 15, 2035	250	250
6.125% September 15, 2037	250	250
4% May 1, 2039(1)	—	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	400
4.1% June 15, 2049	400	400
3.32% April 15, 2050	400	—
	6,053	5,140
Finance lease obligations:		
Purchased-power contracts	1,237	1,255
Other	39	15
	1,276	1,270
	7,329	6,410
Current portion of long-term debt	(411)	(56)
Unamortized discount on long-term debt	(13)	(12)
Unamortized debt issuance costs	(39)	(36)
Total	6,866	6,306

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

MATURITIES OF LONG-TERM DEBT[1] *(Dollars in millions)*		
2021	$	385
2022		18
2023		450
2024		—
2025		—
Thereafter		5,200
Total	$	6,053

(1) *Excludes finance lease obligations, discounts, 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, 2020 is callable subject to premiums:

CALLABLE LONG-TERM DEBT *(Dollars in millions)*		
Subject to make-whole provisions	$	6,053

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 our bond agreements (indentures). These indentures require, among other things, the satisfaction of pro forma earnings-coverage tests on first mortgage bond interest and the availability of sufficient mortgaged property to support the additional bonds, after giving effect to prior bond redemptions. The most restrictive of these tests (the property test) would permit the issuance, subject to CPUC authorization, of additional first mortgage bonds of $6.5 billion at SDG&E at December 31, 2020.

In September 2020, SDG&E issued $800 million of 1.70% first mortgage bonds maturing in 2030 and received proceeds of $792 million (net of debt discount, underwriting discounts and debt issuance costs of $8 million). SDG&E used a portion of the proceeds from the offering to redeem $176 million, prior to a scheduled maturity in 2034, and $75 million, prior to a scheduled maturity in 2039, of tax-exempt industrial development revenue refunding bonds in December 2020. SDG&E used the remaining proceeds for general corporate purposes, including repayment of commercial paper.

In April 2020, SDG&E issued $400 million of 3.32% first mortgage bonds maturing in 2050 and received proceeds of $395 million (net of debt discount, underwriting discounts and debt issuance costs of $5 million). SDG&E used $200 million of the proceeds from the offering to repay line of credit borrowings, and the remaining proceeds for working capital and other general corporate purposes.

Other Long-Term Debt

In the first quarter of 2020, SDG&E borrowed $200 million from its line of credit and classified it as long-term debt based on the term of the line of credit. In the second quarter of 2020, SDG&E repaid these borrowings with proceeds from the issuance of first mortgage bonds, which we discuss above.

NOTE 6. INCOME TAXES

We provide our calculations of ETRs in the following table.

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

	Years ended December 31,		
	2020	2019	2018
Income tax expense	$ 190	$ 171	$ 173
Income before income taxes	$ 1,014	$ 938	$ 842
Effective income tax rate	19 %	18 %	21 %

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
- state income taxes

We present in the table below reconciliations 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,		
	2020	2019	2018
U.S. federal statutory income tax rate	21 %	21 %	21 %
State income taxes, net of federal income tax benefit	5	6	5
Depreciation	3	3	3
Excess deferred income taxes outside of ratemaking	—	(3)	—
Amortization of excess deferred income taxes	(1)	(1)	(1)
Allowance for equity funds used during construction	(2)	(1)	(2)
Repairs expenditures	(3)	(3)	(3)
Self-developed software expenditures	(4)	(3)	(2)
Other, net	—	(1)	—
Effective income tax rate	19 %	18 %	21 %

The remeasurement of the deferred income tax balance at SDG&E in December 2017, as a result of the TCJA, resulted in excess deferred income taxes that previously had been collected from ratepayers at the higher rate. In a January 2019 decision, the CPUC directed certain excess deferred income tax balances generated by activities outside of ratemaking be allocated to shareholders rather than ratepayers. As a result, in 2019, SDG&E recorded an income tax benefit of $31 million from the release of a portion of the regulatory liability established in connection with 2017 tax reform for excess deferred income tax balances.

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

TCJA REMEASUREMENT – REDUCTION TO DEFERRED INCOME TAX BALANCES
(Dollars in millions)

	Year ended December 31, 2020					
	FERC ACs 182.3/254	FERC AC 190(1), (2)	FERC AC 282	FERC AC 283(3)	Total Deferred	FERC AC 410 (Exp)
FERC	$ 599	$ 5	$ (421)	$ (183)	$ (599)	$ 0
CPUC	829	6	(474)	(361)	(829)	0
Shareholder	0	2	26	0	28	(28)
Total	$ 1,428	$ 13	$ (869)	$ (544)	$ (1,400)	$ (28)

(1) *Since the table is summarizing a reduction to the net deferred income tax liability balance, the decrease to the 190 deferred tax asset account in this table is shown as positive.*

(2) *Does not include the net operating loss deferred tax asset related to FERC Transmission.*

(3) *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, we made a $38 million true-up primarily related to the gross-up on flow-through deferred taxes required under ASC 740, Income Taxes. This resulted in additional reduction of deferred tax liabilities and an increase in net regulatory liabilities. In the first quarter of 2019, we reclassed $31 million of certain excess deferred taxes out of regulatory liabilities and into Shareholder, because these items were not related to plant in service nor were they part of the reduction to rate base for accumulated deferred income taxes.

The table below represents the amount of protected and unprotected excess deferred income taxes related to plant in service (excluding gross-up) as of December 31, 2020, 2019, 2018 and 2017.

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

(Dollars in millions)

	Years ended December 31,			
	2020(2)	2019	2018	2017
FERC - Protected	$ 371	$ 380	$ 382	$ 384
CPUC - Protected	450	457	463	469
FERC - Unprotected	6	1	3	6
CPUC - Unprotected	(117)	(118)	(120)	(122)
Total	$ 710	$ 720	$ 728	$ 737

(1) Does not include the net operating loss deferred tax asset related to FERC Transmission.

(2) Includes adjustment to reclass certain transmission-related excess deferred income taxes between Protected and Unprotected pursuant to FERC Order 864.

For plant in service, we use the Average Rate Assumption Method (ARAM) to amortize the excess deferred income taxes over the book life of the underlying property. During 2019, we received a final decision from the CPUC in its general rate case allowing us to track differences between using ARAM and straight-line amortization over a six-year period for certain unprotected items. The CPUC decision also allowed us to track differences related to the inclusion of new cost of removal accruals in the ARAM calculation. As of December 31, 2020, we have not received a final regulatory order from the FERC regarding how customer rates should be reduced for excess deferred income taxes. Future potential regulatory orders and IRS guidance could impact our classification of protected and unprotected amounts indicated above as well as the inclusion of new cost of removal accruals in the ARAM calculation.

Under ARAM, we reduced our regulatory liability related to excess deferred income taxes by $10 million, $8 million, and $9 million in 2020, 2019, and 2018 respectively, 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). The table below reflects these adjustments for the following FERC accounts as of December 31, 2020, 2019, and 2018.

ARAM - REGULATORY LIABILITY / DEFERRED INCOME TAXES
(Dollars in millions)

	Years ended December 31,			
	2020	2019	2018	Amortization Period
FERC ACs 254/411.1				
FERC - Protected	$ 3	$ 2	$ 2	Book Depreciation Life
CPUC - Protected	7	6	6	Book Depreciation Life
FERC - Unprotected	2	2	3	Book Depreciation Life
CPUC - Unprotected	(2)	(2)	(2)	Book Depreciation Life
Total	$ 10	$ 8	$ 9	

The components of income tax expense are as follows.

INCOME TAX EXPENSE (BENEFIT)
(Dollars in millions)

	Years ended December 31,		
	2020	2019	2018
Current:			
U.S. federal	$ 121	$ 35	$ 104
U.S. state	34	31	30
Total	155	66	134
Deferred:			
U.S. federal	11	75	17
U.S. state	25	32	24
Total	36	107	41
Deferred investment tax credits	(1)	(2)	(2)
Total income tax expense	$ 190	$ 171	$ 173

The table below presents the components of deferred income taxes:

DEFERRED INCOME TAXES
(Dollars in millions)

	December 31, 2020	December 31, 2019
Deferred income tax liabilities:		
Differences in financial and tax bases of utility plant and other assets	$ 1,833	$ 1,735
Regulatory balancing accounts	224	141
Right-of-use assets – operating leases	28	32
Property taxes	34	30
Other	2	14
Total deferred income tax liabilities	2,121	1,952
Deferred income tax assets:		
Tax credits	5	6
Postretirement benefits	14	37
Compensation-related items	12	6
Operating lease liabilities	28	32
Bad debt allowance	18	3
State income taxes	8	7
Accrued expenses not yet deductible	14	9
Other	3	4
Total deferred income tax assets	102	104
Net deferred income tax liability	$ 2,019	$ 1,848

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)

	2020	2019	2018
Balance at January 1	$ 12	$ 11	$ 10
Increase in prior period tax positions	1	1	1
Balance at December 31	$ 13	$ 12	$ 11
Of December 31 balance, amounts related to tax positions that if recognized in future years would			
decrease the effective tax rate(1)	$ (10)	$ (9)	$ (9)
increase the effective tax rate(1)	1	1	1

(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,		
	2020	2019	2018
Potential resolution of audit issues with various U.S. federal, state and local taxing authorities	$ (6)	$ (6)	$ (6)

SDG&E accrued negligible amounts for interest expense and penalties at December 31, 2020 and 2019 on the Balance Sheet, and recorded negligible amounts of interest expense and penalties in each of 2020, 2019 and 2018 on the Statement of Operations.

INCOME TAX AUDITS

We are subject to U.S. federal income tax and state income tax. We remain subject to examination for U.S. federal tax years after 2016 and state tax years after 2012.

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 balance sheet;
- 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 a member of the Sempra Energy board of directors who was a participant 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 $512 million and $488 million at December 31, 2020 and 2019, respectively.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

Benefit Plan Amendments Affecting 2019

In 2019, 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 $3 million in 2019.

Settlement Accounting for Lump Sum Payments

When applicable, we record settlement charges for lump sum payments from our nonqualified pension plans that are in excess of the respective plan’s service cost plus interest cost. SDG&E recorded settlement charges of $4 million in 2018.

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 settlement charges in net periodic benefit cost of $22 million. The settlement charges were recorded as regulatory assets on the Balance Sheet.

Special Termination Benefits Affecting 2018

In 2018, certain nonrepresented employees age 62 or older with 5 years of service or age 55 to 61 with 10 years of service that retired under the Voluntary Retirement Enhancement Program offered that year 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.

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 2020 and 2019, and a statement of the funded status at December 31, 2020 and 2019:

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

	Pension benefits		Other postretirement benefits	
	2020	2019	2020	2019
CHANGE IN PROJECTED BENEFIT OBLIGATION				
Net obligation at January 1	$ 895	$ 814	$ 177	$ 170
Service cost	31	30	4	4
Interest cost	30	34	6	7
Contributions from plan participants	—	—	8	7
Actuarial loss	37	61	17	7
Plan amendments	—	3	—	—
Benefit payments	(18)	(18)	(20)	(18)
Settlements	(52)	(39)	—	—
Transfer of liability from other plans	(10)	10	1	—
Net obligation at December 31	913	895	193	177
CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	739	600	197	172
Actual return on plan assets	94	135	26	36
Employer contributions	52	52	1	—
Contributions from plan participants	—	—	8	7
Benefit payments	(18)	(18)	(20)	(18)
Settlements	(52)	(39)	—	—
Transfer of assets from other plans	4	9	1	—
Fair value of plan assets at December 31	819	739	213	197
Funded status at December 31	$ (94)	$ (156)	$ 20	$ 20
Net recorded (liability) asset at December 31	$ (94)	$ (156)	$ 20	$ 20

Actuarial losses (gains) fluctuate based on changes in assumptions that we describe below in "Assumptions for Pension and Other Postretirement Benefit Plans" and updates to census data. In 2020, 2019 and 2018, the Society of Actuaries released updated mortality improvement projection scales, reflecting changes to projected observed longevity improvements in its mortality tables. We have incorporated these assumptions, adjusted for the SDGE's actual mortality experience, in our calculations for each of those years.

- Actuarial losses in pension plans in 2020 were driven primarily by a decrease in discount rates. These actuarial losses were offset by actuarial gains due to a decrease in the interest crediting rate for the cash balance plans.
- Actuarial losses in PBOP plans in 2020 were driven primarily by a decrease 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% corridor accounting method. Under the corridor accounting method, if as of the beginning of a year unrecognized net gain or loss exceeds 10% 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% corridor accounting methods help mitigate volatility of net periodic benefit costs from year to year.

Defined benefit pension and other postretirement plans with an aggregated overfunded status are recognized as an asset and with an aggregated underfunded status are recognized as a liability; 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 the greater of:

- a minimum required funding amount as required by the IRS;
- the amount required to maintain an 85% Adjusted Funding Target Attainment Percentage as defined by the Pension Protection Act of 2006, as amended; or
- beginning January 1, 2019 and for the duration of the 2019 GRC cycle, a fixed amount equal to the estimated annual service cost as defined by U.S. GAAP plus one year of a 14-year amortization of the unfunded projected benefit obligation of the pension plan as of January 1, 2019, and limited to an annual amount that keeps the fair value of the pension plan assets from exceeding 110% of the pension benefit obligation of the plan.

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
(Dollars in millions)

	Pension benefits		Other postretirement benefits	
	2020	2019	2020	2019
Noncurrent assets	$ —	$ —	$ 20	$ 20
Current liabilities	(2)	(3)	—	—
Noncurrent liabilities	(92)	(153)	—	—
Net recorded (liability) asset	$ (94)	$ (156)	$ 20	$ 20

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	
	2020	2019
Net actuarial loss	$ (8)	$ (9)
Prior service cost	(2)	(7)
Total	$ (10)	$ (16)

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)

	2020	2019
Projected benefit obligation	$ 887	$ 861
Accumulated benefit obligation	834	818
Fair value of plan assets	819	739

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)

	2020	2019
Projected benefit obligation	$ 26	$ 34
Accumulated benefit obligation	22	27

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		
	2020	2019	2018	2020	2019	2018
NET PERIODIC BENEFIT COST						
Service cost	$ 31	$ 30	$ 30	$ 4	$ 4	$ 5
Interest cost	30	34	35	6	7	7
Expected return on assets	(49)	(38)	(47)	(10)	(11)	(13)
Amortization of:						
Prior service cost	2	3	2	—	2	3
Actuarial loss (gain)	3	11	1	(3)	(2)	(3)
Settlement charges	—	—	26	—	—	—
Special termination benefits	—	—	—	—	—	3
Net periodic benefit cost	17	40	47	(3)	—	2
Regulatory adjustment	38	14	(8)	3	—	—
Total expense recognized	55	54	39	—	—	2
CHANGES IN PLAN ASSETS AND BENEFIT OBLIGATIONS RECOGNIZED IN OCI						
Net loss (gain)	6	5	(1)	—	—	—
Prior service cost	—	2	8	—	—	—
Transfer of actuarial loss	(7)	—	—	—	—	—
Transfer of prior service cost	(5)	—	—	—	—	—
Amortization of actuarial loss	(1)	—	(1)	—	—	—
Amortization of prior service cost	(1)	(1)	—	—	—	—
Settlements	—	—	(4)	—	—	—
Total recognized in OCI	(8)	6	2	—	—	—
Total recognized in net periodic benefit cost and OCI	$ 47	$ 60	$ 41	$ —	$ —	$ 2

Assumptions for Pension and Other Postretirement Benefit Plans

Benefit Obligation and Net Periodic Benefit Cost

We develop the discount rate assumptions using a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flows to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of corporate bonds with a Bloomberg Composite of AA or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plans' projected benefit payments discounted at this rate with the market value of the bonds selected.

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	
	2020	2019	2020	2019
Discount rate	2.73 %	3.44 %	2.85 %	3.55 %
Interest crediting rate(1)(2)	1.62	2.28	1.62	2.28
Rate of compensation increase	2.70-10.00	2.70-10.00	2.70-10.00	2.70-10.00

(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		
	2020	2019	2018	2020	2019	2018
Discount rate	3.44 %	4.29 %	3.64 %	3.55 %	4.30 %	3.65 %
Expected return on plan assets	7.00	7.00	7.00	5.51	6.92	6.94
Interest crediting rate(1)(2)	2.28	3.36	2.80	2.28	3.36	2.80
Rate of compensation increase	2.70-10.00	2.00-10.00	2.00-10.00	2.70-10.00	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		
	2020	2019	2018	2020	2019	2018
Health care cost trend rate assumed for next year	6.00 %	6.25 %	6.50 %	4.75 %	4.75 %	4.75 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend)	4.75 %	4.75 %	4.75 %	4.50 %	4.50 %	4.50 %
Year the rate reaches the ultimate trend	2025	2025	2025	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 SDG&E's 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:

- 33% domestic equity
- 22% international equity
- 21% long credit
- 10% diversified real assets
- 7% return-seeking credit
- 5% ultra-long duration government securities
- 2% other diversifying assets

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

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

This allocation results in a 74% target allocation to return-seeking assets and a 26% target allocation to risk-mitigating assets. 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 6.75% 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 4% and 12% on return-seeking assets and between 1% and 4% 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 its current retirees. The assets of these plans are placed into the pension master trust and other Voluntary Employee Beneficiary Association trusts. Certain assets of SDG&E's PBOP plans are held in the pension master trust, which invests a portion of the assets in completion portfolios that aim to reduce interest rate risk, thereby resulting in an overall target allocation of 38% to return-seeking assets and 62% to risk-mitigating assets for these well-funded plans. SDG&E's assets held in other Voluntary Employee Beneficiary Association trusts are invested in accordance with a de-risking glidepath that reduces the assets' exposure to risk as the trusts become better funded. These specific allocations are periodically reviewed to help 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, 2020		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Cash and cash equivalents	$ 7	$ —	$ 7
Equity securities:			
Domestic	931	—	931
International	563	—	563
Registered investment companies	183	—	183
Fixed income securities:			
Domestic government bonds and government agencies	238	34	272
International government bonds	—	13	13
Domestic corporate bonds	—	418	418
International corporate bonds	—	61	61
Registered investment companies	—	37	37
Other	2	(1)	1
Total investment assets in the fair value hierarchy	$ 1,924	$ 562	2,486
Accounts receivable/payable, net			13
Investments measured at NAV:			
Common/collective trusts			493
Private equity funds			10
Total investment assets			$ 3,002
SDG&E’s proportionate share of investment assets			$ 819
SoCalGas’ proportionate share of investment assets			$ 1,969

	Fair value at December 31, 2019		
	Level 1	Level 2	Total
Sempra Energy Consolidated:			
Cash and cash equivalents	$ 17	$ —	$ 17
Equity securities:			
Domestic	923	—	923
International	555	1	556
Registered investment companies	96	—	96
Fixed income securities:			
Domestic government bonds and government agencies	228	39	267
International government bonds	—	9	9
Domestic corporate bonds	—	346	346
International corporate bonds	—	62	62
Registered investment companies	—	2	2
Total investment assets in the fair value hierarchy	$ 1,819	$ 459	2,278
Accounts receivable/payable, net			(38)
Investments measured at NAV:			
Common/collective trusts			417
Private equity funds			5
Total investment assets			$ 2,662
SDG&E’s proportionate share of investment assets			$ 739
SoCalGas’ proportionate share of investment assets			$ 1,737

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, 2020		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 17	$ —	$ 17
International	11	—	11
Registered investment companies	80	—	80
Fixed income securities:			
Domestic government and government agencies	38	2	40
Domestic corporate bonds	—	8	8
International corporate bonds	—	1	1
Registered investment companies	—	7	7
Total investment assets in the fair value hierarchy	146	18	164
Accounts receivable/payable, net			(2)
Investments measured at NAV – Common/collective trusts			51
Total investment assets			$ 213

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

	Fair value at December 31, 2019		
	Level 1	Level 2	Total
Equity securities:			
Domestic	$ 21	$ —	$ 21
International	13	—	13
Registered investment companies	68	—	68
Fixed income securities:			
Domestic government and government agencies	32	1	33
Domestic corporate bonds	—	8	8
International corporate bonds	—	1	1
Registered investment companies	—	8	8
Total investment assets in the fair value hierarchy	134	18	152
Accounts receivable/payable, net			(2)
Investments measured at NAV – Common/collective trusts			47
Total investment assets			$ 197

Future Payments

We expect to contribute the following amounts to our pension and PBOP plans in 2021:

EXPECTED CONTRIBUTIONS *(Dollars in millions)*		
Pension plans	$	53
Other postretirement benefit plans		1

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	
2021	$	112	$	10
2022		68		10
2023		65		10
2024		61		10
2025		60		10
2026-2030		263		47

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)*					
2020		2019		2018	
$	16	$	15	$	15

The market value of Sempra Energy common stock held by the savings plans was $1.1 billion and $1.3 billion at December 31, 2020 and 2019, 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:

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

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

In the three years ended December 31, 2020, Sempra Energy had the following types of equity awards outstanding:

- *Nonqualified 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 three-year period (for awards granted in 2020 and 2019) or over a four-year period (for awards granted in 2010 or earlier), 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 (excluding water companies) and the S&P 500 Index. We use long-term analyst consensus growth estimates for S&P 500 Utilities Index peer companies (excluding water companies) to develop our targets for awards that vest based on EPS growth.
  - For awards granted during or after 2014, up to an additional 100% 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% 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% for performance in the bottom quartile. However, in no event will more than an additional 100% 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 ratably over three-year service periods (for awards granted in 2019), or at the end of three-year (for awards granted during 2015 through 2018) or four-year service periods (for awards granted prior to 2015).

For RSU awards, vesting may be subject to earlier forfeiture upon termination of employment and accelerated vesting upon a change in control under the applicable LTIP, in accordance with severance pay agreements, or at the discretion of the Compensation and Talent Committee of Sempra Energy's board of directors. Dividend equivalents on shares subject to RSUs are reinvested to purchase additional common shares that become subject to the same vesting conditions as the RSUs to which the dividends relate.

SHARE-BASED AWARDS AND COMPENSATION EXPENSE

At December 31, 2020, 6,927,284 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 nonqualified stock options 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 as the award requires service through the end of the year in which it 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,		
	2020	2019	2018
Share-based compensation expense, before income taxes	$ 11	$ 10	$ 12
Income tax benefit	(3)	(3)	(3)
	$ 8	$ 7	$ 9
Capitalized share-based compensation cost	$ 7	$ 6	$ 6
Excess income tax deficiency	$ 3	$ 1	$ 3

SEMPRA ENERGY NONQUALIFIED STOCK OPTIONS

We use a Black-Scholes option-pricing model to estimate the fair value of each nonqualified 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 a blend of the historical and implied volatility of Sempra Energy's common stock price. The average expected term for options is based on the vesting schedule, contractual term of the option, 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 term estimated at the date of the grant. In 2020 and 2019, Sempra Energy's board of directors granted 154,860 and 261,075 nonqualified stock options, respectively, that are exercisable over a three-year period. No stock options were granted to SDG&E's executives in 2018, 2019 and 2020. The weighted-average per-share fair value for options granted was $19.76 and $13.20 in 2020 and 2019, respectively. To calculate this fair value, we used the Black-Scholes model with the following weighted-average assumptions:

KEY ASSUMPTIONS FOR STOCK OPTIONS GRANTED

	Years ended December 31,	
	2020	2019
Stock price volatility	18.78 %	18.63 %
Expected term	5.34 years	5.34 years
Risk-free rate of return	1.68 %	2.49 %
Annual dividend yield	2.60 %	3.35 %

The following table shows a summary of nonqualified stock options at December 31, 2020 and activity for the year then ended:

NONQUALIFIED STOCK OPTIONS

	Common shares under options	Weighted-average exercise price	Weighted-average remaining contractual term (in years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2020	247,577	$ 105.86		
Granted	154,860	$ 149.12		
Exercised	(4,400)	$ 55.90		
Forfeited/canceled	(32,642)	$ 149.12		
Outstanding at December 31, 2020	365,395	$ 120.93	8.34	$ 2
Vested or expected to vest at December 31, 2020	349,596	$ 120.28	8.32	$ 2
Exercisable at December 31, 2020	81,061	$ 106.76	8.00	$ 2

The aggregate intrinsic value at December 31, 2020 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 nonqualified stock options exercised in the last three years was:

- $0.4 million in 2020
- $4 million in 2019
- $9 million in 2018

We expect a negligible amount of total compensation cost related to nonvested stock options not yet recognized as of December 31, 2020 to be recognized over a weighted-average period of 1.3 years. The weighted-average per-share fair value for nonqualified stock options granted in 2019 was $106.76.

We received cash of $0.2 million and $3 million from stock option exercises during 2020 and 2019, respectively.

SEMPRA ENERGY RESTRICTED STOCK UNITS

We use a Monte-Carlo simulation model to estimate the fair value of our RSUs that vest based on Sempra Energy's total return to shareholders. Our determination of fair value is affected by the historical volatility of the common stock price for Sempra Energy and its peer group companies. The valuation also is affected by the risk-free rates of return and a number of other variables. Below are key assumptions for RSUs granted in the last three years:

KEY ASSUMPTIONS FOR RSUs GRANTED

	Years ended December 31,		
	2020	2019	2018
Stock price volatility	16.35 %	17.74 %	17.46 %
Risk-free rate of return	1.55 %	2.46 %	2.00 %

The following table shows a summary of RSUs at December 31, 2020 and activity for the year then ended:

RESTRICTED STOCK UNITS

	Performance-based restricted stock units		Service-based restricted stock units	
	Units	Weighted-average grant-date fair value	Units	Weighted-average grant-date fair value
Nonvested at January 1, 2020	1,086,981	$ 109.85	415,787	$ 119.96
Granted	265,236	$ 155.62	165,847	$ 138.91
Vested	(403,302)	$ 110.45	(230,612)	$ 112.11
Forfeited	(54,954)	$ 134.90	(7,445)	$ 140.18
Nonvested at December 31, 2020(1)	893,961	$ 121.61	343,577	$ 121.59
Expected to vest at December 31, 2020	882,903	$ 121.45	339,025	$ 121.46

(1) *Each RSU represents the right to receive one share of our common stock if applicable performance conditions are satisfied. For all performance-based RSUs, up to an additional 100% of the shares represented by the RSUs may be issued if Sempra Energy exceeds target performance conditions.*

In 2020, 2019 and 2018, the total fair value of RSU shares vested during the year was $70 million, $36 million and $32 million, respectively.

We expect $28 million of total compensation cost related to nonvested RSUs not yet recognized as of December 31, 2020 to be recognized over a weighted-average period of 1.7 years. The weighted-average per-share fair values for performance-based RSUs granted were $113.54 and $105.03 in 2019 and 2018, respectively. The weighted-average per-share fair values for service-based RSUs granted were $112.50 and $107.60 in 2019 and 2018, respectively.

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 could cause our asset values to fall or our liabilities to 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 have derivatives that are (1) cash flow hedges, (2) fair value hedges, 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 hedges), on the balance sheet (regulatory offsets), or recognized in earnings (fair value hedges and undesignated derivatives not subject to rate recovery). We classify cash flows from the 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.

ENERGY DERIVATIVES

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

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

The following table summarizes net energy derivative volumes.

NET ENERGY DERIVATIVE VOLUMES
(Quantities in millions)

Commodity	Unit of measure	December 31, 2020	December 31, 2019
Natural gas	MMBtu	16	37
Electricity	MWh	1	2
Congestion revenue rights	MWh	43	48

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

DERIVATIVE INSTRUMENTS ON THE BALANCE SHEET
(Dollars in millions)

	December 31, 2020			
	Other current assets(1)	Other long-term assets	Other current liabilities	Deferred credits and other
Derivatives not designated as hedging instruments:				
Commodity contracts subject to rate recovery	$ 32	$ 95	$ (28)	$ (25)
Associated offsetting commodity contracts	(1)	—	1	—
Net amounts presented on the balance sheet	31	95	(27)	(25)
Additional cash collateral for commodity contracts subject to rate recovery	24	—	—	—
Total(2)	$ 55	$ 95	$ (27)	$ (25)

(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, 2019			
	Other current assets(1)	Other long-term assets	Other current liabilities	Deferred credits and other
Derivatives designated as hedging instruments:				
Commodity contracts subject to rate recovery	30	76	(41)	(47)
Associated offsetting commodity contracts	(4)	(3)	4	3
Associated offsetting cash collateral	—	—	14	—
Net amounts presented on the balance sheet	26	73	(23)	(44)
Additional cash collateral for commodity contracts subject to rate recovery	16	—	—	—
Total(2)	$ 42	$ 73	$ (23)	$ (44)

(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	2020	2019	2018
Commodity contracts subject to rate recovery	Cost of Electric Fuel and Purchased Power	$ 88	$ (140)	$ 279

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.

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, set forth our financial assets and liabilities that were accounted for at fair value on a recurring basis at December 31, 2020 and 2019. 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-valued 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 under “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 or income 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 December 31, 2020, and 2019.

RECURRING FAIR VALUE MEASURES
(Dollars in millions)

	Fair value at December 31, 2020			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts:				
Equity securities	$ 358	$ 6	$ —	$ 364
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	41	24	—	65
Municipal bonds	—	326	—	326
Other securities	—	270	—	270
Total debt securities	41	620	—	661
Total nuclear decommissioning trusts(1)	399	626	—	1,025
Commodity contracts subject to rate recovery	5	—	121	126
Effect of netting and allocation of collateral(2)	18	—	6	24
Total	$ 422	$ 626	$ 127	$ 1,175
Liabilities:				
Commodity contracts subject to rate recovery	$ —	$ —	$ 52	$ 52
Total	$ —	$ —	$ 52	$ 52

	Fair value at December 31, 2019			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts:				
Equity securities	$ 503	$ 6	$ —	$ 509
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	46	11	—	57
Municipal bonds	—	282	—	282
Other securities	—	226	—	226
Total debt securities	46	519	—	565
Total nuclear decommissioning trusts(1)	549	525	—	1,074
Commodity contracts subject to rate recovery	1	3	95	99
Effect of netting and allocation of collateral(2)	10	—	6	16
Total	$ 560	$ 528	$ 101	$ 1,189
Liabilities:				
Commodity contracts subject to rate recovery	14	—	67	81
Effect of netting and allocation of collateral(2)	(14)	—	—	(14)
Total	$ —	$ —	$ 67	$ 67

(1) *Excludes cash, cash equivalents and receivables (payables), net.*
(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 table below 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, 2020	2019	2018
Balance at January 1	$ 28	$ 179	$ (28)
Realized and unrealized gains (losses)	19	(184)	209
Allocated transmission instruments	6	6	10
Settlements	16	27	(12)
Balance at December 31	$ 69	$ 28	$ 179
Change in unrealized gains (losses) relating to instruments still held at December 31	$ 34	$ (139)	$ 183

(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
2021	$ (1.81)	to	$ 14.11	$ (0.12)
2020	(3.77)	to	6.03	(1.58)
2019	(8.57)	to	35.21	(2.94)

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 at December 31 were as follows:

LONG-TERM, FIXED-PRICE ELECTRICITY POSITIONS PRICE INPUTS

Settlement year	Price per MWh			Weighted-average price per MWh
2020	$ 19.60	to	$ 78.10	$ 39.71
2019	21.00	to	61.15	37.92

A significant increase (decrease) in market electricity forward prices would result in a significantly higher (lower) fair value. We summarize long-term, fixed-price electricity position volumes in Note 9.

Realized gains and losses associated with CRRs and long-term, fixed-price electricity positions, which are recoverable in rates, are recorded in Cost of Electric Fuel and Purchased Power on the Statement of Operations. Because unrealized gains and losses are recorded as regulatory assets and liabilities, they 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.

FAIR VALUE OF FINANCIAL INSTRUMENTS
(Dollars in millions)

	December 31, 2020				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 6,053	$ —	$ 7,184	$ —	$ 7,184

	December 31, 2019				
	Carrying	Fair value			
	amount	Level 1	Level 2	Level 3	Total
Total long-term debt(1)	$ 5,140	$ —	$ 5,662	$ —	$ 5,662

(1) Before reductions of unamortized discount and debt issuance costs of $52 million and $48 million at December 31, 2020 and 2019, respectively, and excluding finance lease obligations of $1,276 million and $1,270 million at December 31, 2020 and 2019, respectively.

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

NOTE 11. PREFERRED STOCK

SDG&E is authorized to issue up to 45 million shares of preferred stock. At December 31, 2020 and 2019, 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% ownership interest in SONGS, a nuclear generating facility near San Clemente, California, which permanently ceased operations in June 2013 after an extended outage 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 in SDG&E's Statement of Operations.

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 the outage. In July 2018, the CPUC approved a settlement agreement and, in August 2018, SDG&E, Edison, Cal PA, TURN and other intervenors submitted a notice that they accepted the settlement agreement, which provided for various disallowances, refunds and rate recoveries.

In connection with the settlement agreement, and in exchange for the release of certain SONGS-related claims, in January 2018, SDG&E and Edison entered into a utility shareholder agreement, which became effective upon CPUC approval of the settlement agreement in July 2018, 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 settlement agreement. In exchange for Edison's reimbursement, the parties mutually released each other from all claims that each party had or could have asserted related to the steam generator replacement failure and its aftermath. Edison's payment obligation commenced in October 2018, and amounts are due to SDG&E quarterly thereafter until April 2022. At December 31, 2020, SDG&E has a receivable from Edison, including accrued interest, totaling $49 million, with $37 million classified as current and $12 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.

We expect the majority of the work to take 10 years after receipt of all the required permits. The coastal development permit, the last permit required to be obtained, was issued in October 2019. The Samuel Lawrence Foundation filed a writ petition under the California Coastal Act in LA Superior Court in December 2019 seeking to invalidate this permit and to obtain injunctive relief to stop decommissioning work. In September 2020, the Samuel Lawrence Foundation filed another writ petition under the California Coastal Act in LA Superior Court seeking to set aside the CCC's July 2020 approval of the inspection and maintenance plan for the SONGS' canisters and to obtain injunctive relief to stop decommissioning work. Major decommissioning work began in 2020 and has not been interrupted by the writ petitions filed by the Samuel Lawrence Foundation. Decommissioning of Unit 1, removed from service in 1992, is largely complete. The remaining work for Unit 1 will be completed once Units 2 and 3 are dismantled and the spent fuel is removed from the site. The spent fuel is currently being stored on-site, until the DOE identifies a spent fuel storage facility and puts in place a program for the fuel's disposal, as we discuss below. SDG&E is responsible for approximately 20% of the total decommissioning costs.

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. SDG&E classifies debt and equity securities held in the NDT as available-for-sale. The NDT assets are presented on the Balance Sheet at fair value with the offsetting credits recorded in noncurrent Regulatory Liabilities.

Except for the use of funds for the planning of decommissioning activities or NDT administrative costs, CPUC approval is required for SDG&E to access the NDT assets to fund SONGS decommissioning costs for Units 2 and 3. In December 2020, SDG&E received authorization from the CPUC to access NDT funds of up to $89 million for forecasted 2021 costs.

In September 2020, the IRS and the U.S. Department of the Treasury published final 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 final regulations adopted most of the provisions of the proposed regulations issued in December 2016. The final regulations apply to taxable years ending on or after September 4, 2020 and confirm that the definition of "nuclear decommissioning costs" includes amounts related to the storage of spent nuclear fuel at both on-site and off-site ISFSIs.

The final regulations also clarify that costs incurred for ISFSIs that may be or are expected to be reimbursed by the DOE may be paid or reimbursed from a qualified trust fund. Accordingly, the final regulations allow SDG&E the option to access qualified trust funds to recover spent fuel storage 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.

Nuclear Decommissioning Trusts

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, 2020:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies(1)	$ 64	$ 1	$ —	$ 65
Municipal bonds(2)	308	18	—	326
Other securities(3)	253	17	—	270
Total debt securities	625	36	—	661
Equity securities	112	254	(2)	364
Cash and cash equivalents	3	—	—	3
Receivables (payables), net	(9)	—	—	(9)
Total	$ 731	$ 290	$ (2)	$ 1,019
At December 31, 2019:				
Debt securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	$ 57	$ —	$ —	$ 57
Municipal bonds	270	12	—	282
Other securities	218	9	(1)	226
Total debt securities	545	21	(1)	565
Equity securities	176	339	(6)	509
Cash and cash equivalents	16	—	—	16
Receivables (payables), net	(8)	—	—	(8)
Total	$ 729	$ 360	$ (7)	$ 1,082

(1) *Maturity dates are 2022-2051.*

(2) *Maturity dates are 2021-2056.*

(3) *Maturity dates are 2021-2072.*

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,		
	2020	2019	2018
Proceeds from sales	$ 1,439	$ 914	$ 890
Gross realized gains	156	24	42
Gross realized losses	(17)	(5)	(10)

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

The present value of SDG&E's ARO related to decommissioning costs for the SONGS units was $579 million at December 31, 2020. 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 for all three units is based on a cost study prepared in 2017 that is pending CPUC approval. The ARO 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 2020 dollars is approximately $860 million. We expect SDG&E's undiscounted SONGS decommissioning payments to be $110 million in 2021, $83 million in 2022, $63 million in 2023, $45 million in 2024, $44 million in 2025, and $697 million thereafter.

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. In October 2015, the CCC approved Edison's application to expand the ISFSI. The ISFSI expansion began construction in 2016 and the transfer of the spent nuclear fuel from Units 2 and 3 to the ISFSI began in 2018 and was completed in August 2020. The ISFSI will operate until 2049, when it is assumed that the DOE will have taken custody of all the SONGS spent fuel. The ISFSI would then be decommissioned, and the site restored to its original environmental state. Until then, SONGS owners are responsible for interim storage of spent nuclear fuel at SONGS.

The Nuclear Waste Policy Act of 1982 made the DOE responsible for accepting, transporting, and disposing of spent nuclear fuel. However, it is uncertain when the DOE will begin accepting spent nuclear fuel from SONGS. This delay will lead to increased costs for spent fuel storage. In November 2019, Edison filed a claim for spent fuel management costs in the U.S. Court of Federal Claims for the time period from January 2017 through July 2018. It is unclear when Edison will pursue litigation claims for spent fuel management costs incurred on or after August 1, 2018. 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.

NUCLEAR INSURANCE

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.

As a result of updated coverage assessments, the SONGS owners have nuclear property damage insurance of $130 million, which exceeds the minimum federal requirements of $50 million. This insurance coverage is provided through NEIL. The NEIL policies have specific exclusions and limitations that can result in reduced 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 $3.5 million of retrospective premiums based on overall member claims.

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, 2020, SDG&E did not have loss contingency accruals for legal matters, including associated legal fees that are probable and estimable. We discuss our policy regarding accrual of legal fees in Note 1.

LEASES

A lease exists when a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. We determine if an arrangement is or contains a lease at inception of the contract.

Some of our lease agreements contain nonlease components, which represent activities that transfer a separate good or service to the lessee. As the lessee for both operating and finance leases, we have elected to combine lease and nonlease components as a single lease component for real estate, fleet vehicles, power generating facilities, and pipelines, whereby fixed or in-substance fixed payments allocable to the nonlease component are accounted for as part of the related lease liability and ROU asset. As the lessor, we have elected to combine lease and nonlease components as a single lease component for real estate and power generating facilities if the timing and pattern of transfer of the lease and nonlease components are the same and the lease component would be classified as an operating lease if accounted for separately.

Lessee Accounting

We have operating and finance leases for real and personal property (including office space, land, fleet vehicles, machinery and equipment, warehouses and other operational facilities) and PPAs with renewable energy and peaker plant facilities.

Some of our leases include options to extend the lease terms for up to 20 years, or to terminate the lease within one year. Our lease liabilities and ROU assets are based on lease terms that may include such options when it is reasonably certain that we will exercise the option.

Certain of our contracts are short-term leases, which have a lease term of 12 months or less at lease commencement. We do not recognize a lease liability or ROU asset arising from short-term leases for all existing classes of underlying assets. In such cases, we recognize short-term lease costs on a straight-line basis over the lease term. Our short-term lease costs for the period reasonably reflect our short-term lease commitments.

Certain of our leases contain escalation clauses requiring annual increases in rent ranging from 2% to 4% or based on the Consumer Price Index. The rentals payable under these leases may increase by a fixed amount each year or by a percentage of a base year. Variable lease payments that are based on an index or rate are included in the initial measurement of our lease liability and ROU asset based on the index or rate at lease commencement and are not remeasured because of changes to the index or rate. Rather, changes to the index or rate are treated as variable lease payments and recognized in the period in which the obligation for those payments is incurred.

Similarly, PPAs for the purchase of renewable energy at SDG&E require lease payments based on a stated rate per MWh produced by the facilities, and we are required to purchase substantially all the output from the facilities. SDG&E is required to pay additional amounts for capacity charges and actual purchases of energy that exceed the minimum energy commitments. Under these contracts, we do not recognize a lease liability or ROU asset for leases for which there are no fixed lease payments. Rather, these variable lease payments are recognized separately as variable lease costs. SDG&E estimates these variable lease payments to be $297 million in each of 2021 and 2022, $296 million in 2023, $297 million in 2024, $296 million in 2025 and $3,069 million thereafter.

As of the lease commencement date, we recognize a lease liability for our obligation to make future lease payments, which we initially measure at present value using our incremental borrowing rate at the date of lease commencement, unless the rate implicit in the lease is readily determinable. We determine our incremental borrowing rate based on the rate of interest that we would have to pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. We also record a corresponding ROU asset, initially equal to the lease liability and adjusted for lease payments made at or before lease commencement, lease incentives, and any initial direct costs. We test ROU assets for recoverability whenever events or changes in circumstances have occurred that may affect the recoverability or the estimated useful lives of the ROU assets.

For our operating leases, we recognize a single lease cost on a basis that is consistent with the recovery of such costs in accordance with U.S. GAAP governing rate-regulated operations.

For our finance leases, the interest expense on the lease liability and amortization of the ROU asset are accounted for separately. We recognize amortization of the ROU asset on a basis that is consistent with the recovery of such costs in accordance with U.S. GAAP governing rate-regulated operations.

Our leases do not contain any material residual value guarantees, restrictions or covenants.

Classification of ROU assets and lease liabilities and the weighted-average remaining lease term and discount rate associated with operating and finance leases are summarized in the table below.

LESSEE INFORMATION ON THE BALANCE SHEET

(Dollars in millions)

	December 31, 2020	December 31, 2019
Right-of-use assets:		
Operating leases:		
Right-of-use assets (included in Capital Lease Accounts)	$ 102	$ 130
Finance leases:		
Property, plant and equipment	1,356	1,326
Accumulated depreciation	(80)	(57)
Property, plant and equipment, net	1,276	1,269
Total right-of-use assets	$ 1,378	$ 1,399
Lease liabilities:		
Operating leases:		
Other current liabilities(1)	$ 27	$ 27
Deferred credits and other(2)	73	102
	100	129
Finance leases:		
Current portion of long-term debt and finance leases(1)	26	20
Long-term debt and finance leases(2)	1,250	1,250
	1,276	1,270
Total lease liabilities	$ 1,376	$ 1,399
Weighted-average remaining lease term (in years):		
Operating leases	6	6
Finance leases	19	20
Weighted-average discount rate:		
Operating leases	3.62 %	3.55 %
Finance leases	14.65 %	14.83 %

(1) Reflected as Obligations under Capital Lease - Current for FERC Reporting

(2) Reflected as Obligations under Capital Lease - Non-Current for FERC Reporting

The table below presents the maturity analysis of our lease liabilities and reconciliation to the present value of lease liabilities:

LESSEE MATURITY ANALYSIS OF LIABILITIES

(Dollars in millions)

	December 31, 2020	
	Operating leases	Finance leases(1)
2021	$ 30	$ 194
2022	22	194
2023	17	194
2024	15	189
2025	5	185
Thereafter	22	2,453
Total undiscounted lease payments	111	3,409
Less: imputed interest	(11)	(2,133)
Total lease liabilities	100	1,276
Less: current lease liabilities	(27)	(26)
Long-term lease liabilities	$ 73	$ 1,250

(1) *Substantially all amounts are related to purchased-power contracts.*

Lease Disclosures Under Previous U.S. GAAP

Rent expense for operating leases was $27 million as of December 31, 2018.

The annual amortization charge for PPAs accounted for as capital leases was $11 million in 2018. The annual depreciation charge for fleet vehicles and other assets in 2018 was $2 million.

CONTRACTUAL COMMITMENTS

Natural Gas Contracts

SoCalGas has responsibility for procuring natural gas for both SDG&E's and SoCalGas' core customers in a combined portfolio. SoCalGas buys natural gas under short-term and long-term contracts for this portfolio from various producing regions in the southwestern U.S., U.S. Rockies and Canada, primarily based on published monthly bid-week indices.

SoCalGas transports natural gas primarily under long-term firm interstate pipeline capacity agreements that provide for annual reservation charges, which are recovered in rates. SoCalGas has commitments with interstate pipeline companies for firm pipeline capacity under contracts that expire at various dates through 2032.

Purchased-Power Contracts

For 2021, SDG&E expects to meet its customer power requirements from the following resource types:

- Long-term contracts: 28% (of which 27% is provided by renewable energy contracts expiring on various dates through 2041)
- Other SDG&E-owned generation and tolling contracts: 43%
- Spot market purchases: 29%

Payments on our purchased-power contracts could exceed the minimum commitments based on energy needs. At December 31, 2020, the future minimum payments under long-term purchased-power contracts for SDG&E are as follows:

FUTURE MINIMUM PAYMENTS – PURCHASED-POWER CONTRACTS *(Dollars in millions)*		
2021	$	222
2022		208
2023		173
2024		145
2025		88
Thereafter		794
Total minimum payments(1)	$	1,630

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

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. SDG&E estimates these variable payments to be $66 million in each of 2021 and 2022, $67 million in 2023, $65 million in 2024, $66 million in 2025 and $541 million thereafter. Total payments under purchased-power contracts for SDG&E were $534 million in 2020, $744 million in 2019 and $712 million in 2018.

Construction and Development Projects

At December 31, 2020, SDG&E has commitments to make future payments of $25 million for construction projects that include:

- $1 million for infrastructure improvements for electric and natural gas transmission and distribution systems; and
- $24 million related to spent fuel management at SONGS.

SDG&E expects future payments under these contractual commitments to be $2 million in 2021, $1 million in each of 2022 through 2025 and $19 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 $4 million per year in 2021 through 2025 and $279 million thereafter, subject to escalation of 2% per year, for a remaining 49-year period. At December 31, 2020, the present value of these future payments of $121 million has been recorded as a regulatory asset as the amounts represent a cost that we expect will 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.

We disclose any proceeding under environmental laws to which a government authority is a party when the potential monetary sanctions, exclusive of interest and costs, exceed the lesser of $1 million or 1% of current assets, which was $16 million at December 31, 2020.

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,		
2020	2019	2018
$ 39	$ 39	$ 38

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 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, 2020 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 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, 2020.

ACCRUED LIABILITIES FOR ENVIRONMENTAL MATTERS[1]

(Dollars in millions)

Manufactured-gas sites	Waste disposal sites (PRP)[2]	Other hazardous waste sites	Total[3]
$ —	$ 6	$ 13	$ 19

(1) *Does not include SDG&E's liability for SONGS marine environment mitigation.*

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

(3) *Includes $1 million classified as current liabilities, and $18 million classified as noncurrent liabilities on Balance Sheet.*

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 $84 million, of which $47 million has been incurred through December 31, 2020 and $37 million is accrued for remaining costs through 2053, which is recoverable in rates and included in noncurrent Regulatory Assets on SDG&E's Balance Sheet.

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

GLOSSARY

2019 GRC FD	final decision in the SDG&E's 2019 General Rate Case
AB	California Assembly Bill
AFUDC	allowance for funds used during construction
AMP	Arrearage Management Payment Plan
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
CARB	California Air Resources Board
CCC	California Coastal Commission
CCM	cost of capital adjustment mechanism
COVID-19	coronavirus disease 2019
CPUC	California Public Utilities Commission
CRR	congestion revenue right
DOE	U.S. Department of Energy
DWR	California Department of Water Resources
Edison	Southern California Edison Company, a subsidiary of Edison International
Enova	Enova Corporation
EPS	earnings per common share
ESJ	Energía Sierra Juárez, S. de R.L. de C.V.
ETR	effective income tax rate
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GRC	General Rate Case
IOU	investor-owned utility
IRS	Internal Revenue Service
ISFSI	independent spent fuel storage installation
ISO	Independent System Operator
JV	joint venture
LA Superior Court	Los Angeles County Superior Court
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
LTIP	long-term incentive plan
MMBtu	million British thermal units (of natural gas)
Moody's	Moody's Investors Service
MW	megawatt
MWh	megawatt hour
NAV	net asset value
NCI	noncontrolling interest(s)
NDT	nuclear decommissioning trusts
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission

GLOSSARY *(continued)*

O&M	operation and maintenance expense
OCI	other comprehensive income (loss)
OIR	Order Instituting a Rulemaking
OMEC	Otay Mesa Energy Center
OMEC LLC	Otay Mesa Energy Center LLC
PBOP	postretirement benefits other than pension
PG&E	Pacific Gas and Electric Company
PP&E	property, plant and equipment
PPA	power purchase agreement
PRP	Potentially Responsible Party
REC	renewable energy certificate
ROE	return on equity
ROU	right-of-use
RPS	Renewables Portfolio Standard
RSU	restricted stock unit
S&P	Standard & Poor’s
SDG&E	San Diego Gas & Electric Company
SEC	U.S. Securities and Exchange Commission
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
SONGS OII	CPUC’s Order Instituting Investigation into the SONGS Outage
TCJA	Tax Cuts and Jobs Act of 2017
TO4	Electric Transmission Owner Formula Rate, effective through May 31, 2019
TO5	Electric Transmission Owner Formula Rate, effective June 1, 2019
TURN	The Utility Reform Network
U.S. GAAP	accounting principles generally accepted in the United States of America
Wildfire Fund	the fund established pursuant to AB 1054
Wildfire Legislation	AB 1054 and AB 111

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(9,578,079)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(6,295,969)		
4	Total (lines 2 and 3)		(6,295,969)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(15,874,048)		
6	Balance of Account 219 at Beginning of Current Year		(15,874,048)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		5,839,946		
9	Total (lines 7 and 8)		5,839,946		
10	Balance of Account 219 at End of Current Quarter/Year		(10,034,102)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(9,578,079)		
2					
3			(6,295,969)		
4			(6,295,969)	769,183,643	762,887,674
5			(15,874,048)		
6			(15,874,048)		
7					
8			5,839,946		
9			5,839,946	824,492,862	830,332,808
10			(10,034,102)		

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	21,279,176,891	16,790,643,039
4	Property Under Capital Leases	1,516,748,133	1,307,422,019
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	22,795,925,024	18,098,065,058
9	Leased to Others	112,194,000	112,194,000
10	Held for Future Use		
11	Construction Work in Progress	1,699,907,204	1,101,637,518
12	Acquisition Adjustments	3,750,722	3,750,722
13	Total Utility Plant (8 thru 12)	24,611,776,950	19,315,647,298
14	Accum Prov for Depr, Amort, & Depl	7,688,614,673	5,884,605,346
15	Net Utility Plant (13 less 14)	16,923,162,277	13,431,041,952
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,792,691,932	5,549,614,769
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	866,815,278	305,883,114
22	Total In Service (18 thru 21)	7,659,507,210	5,855,497,883
23	Leased to Others		
24	Depreciation	26,857,031	26,857,031
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	26,857,031	26,857,031
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	2,250,432	2,250,432
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,688,614,673	5,884,605,346

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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
2,805,795,867				1,682,737,985	3
				209,326,114	4
					5
					6
					7
2,805,795,867				1,892,064,099	8
					9
					10
180,006,714				418,262,972	11
					12
2,985,802,581				2,310,327,071	13
896,154,097				907,855,230	14
2,089,648,484				1,402,471,841	15
					16
					17
886,935,252				356,141,911	18
					19
					20
9,218,845				551,713,319	21
896,154,097				907,855,230	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
896,154,097				907,855,230	33

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

Reclassification as of 12/2020 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	158,885,321
Steam Production Plant	280,572,806
Other Production Plant	286,007,470
Transmission Plant	1,454,485,759
Distribution Plant	3,399,879,012
General Plant	197,600,558
Ratemaking Electric	5,777,430,926
Nuclear Decommissioning	1,017,651,413
ASC 410 (FAS 143 and FIN 47) - Electric	(1,025,208,106)
Capital Leases A/D	70,018,335
Leased to Others- Citizens A/D (Sunrise)	25,608,886
Leased to Others- Citizens A/D (SX-PQ)	1,248,145
Cuyamaca Permanent Adjustment	17,855,747
Total Electric	5,884,605,346
Ratemaking Gas	1,107,987,350
FIN 47 - Gas	(211,833,253)
Total Gas	896,154,097
Ratemaking Common	837,694,510
FIN 47 - Common	1,754,275
Capital Lease A/D	68,406,445
Total Common	907,855,230
Total Accumulated Provision EOQ 12/2020	7,688,614,673
Total 13-Month Average Accum. Provision as of 12/31/2020 -Steam Production	268,342,034
Total 13-Month Average Accum. Provision as of 12/31/2020 -Other Production	274,265,268
Total 13-Month Average Accum. Provision as of 12/31/2020 -Transmission Plant	1,386,289,276

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			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	04/16/2021	End of 2020/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	176,890,082	14,451,185
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	177,112,923	14,451,185
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	14,526,518	
9	(311) Structures and Improvements	91,184,790	225,418
10	(312) Boiler Plant Equipment	161,941,815	398,897
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	131,247,085	155,528
13	(315) Accessory Electric Equipment	86,310,766	664,482
14	(316) Misc. Power Plant Equipment	55,474,930	5,286,503
15	(317) Asset Retirement Costs for Steam Production	109,537	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	540,795,441	6,730,828
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	23,709,749	1,103,018
39	(342) Fuel Holders, Products, and Accessories	22,279,073	
40	(343) Prime Movers	106,198,845	
41	(344) Generators	362,261,561	4,130,396
42	(345) Accessory Electric Equipment	33,389,503	416,885
43	(346) Misc. Power Plant Equipment	33,192,345	6,972,347
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	581,257,872	12,622,646
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,122,053,313	19,353,474

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	243,026,226	9,416,341
49	(352) Structures and Improvements	631,967,409	38,346,950
50	(353) Station Equipment	1,907,477,535	64,436,343
51	(354) Towers and Fixtures	905,834,222	16,891,342
52	(355) Poles and Fixtures	747,025,026	201,653,713
53	(356) Overhead Conductors and Devices	724,896,087	102,349,346
54	(357) Underground Conduit	467,460,866	83,059,930
55	(358) Underground Conductors and Devices	505,866,012	51,839,646
56	(359) Roads and Trails	328,926,247	41,771,248
57	(359.1) Asset Retirement Costs for Transmission Plant	-462,713	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	6,462,016,917	609,764,859
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	107,753,051	2,727,955
61	(361) Structures and Improvements	9,892,776	2,415,185
62	(362) Station Equipment	605,840,505	12,073,770
63	(363) Storage Battery Equipment	127,582,403	-1,616,447
64	(364) Poles, Towers, and Fixtures	857,604,224	100,609,719
65	(365) Overhead Conductors and Devices	850,751,702	127,560,866
66	(366) Underground Conduit	1,407,832,540	192,259,031
67	(367) Underground Conductors and Devices	1,718,523,384	55,125,715
68	(368) Line Transformers	718,714,010	41,731,050
69	(369) Services	583,772,611	39,477,767
70	(370) Meters	266,653,804	6,794,784
71	(371) Installations on Customer Premises	9,733,226	297,968
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	32,869,649	1,258,708
74	(374) Asset Retirement Costs for Distribution Plant	22,654,786	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	7,320,178,671	580,716,071
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	45,611,646	
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	58,146	
90	(393) Stores Equipment	46,522	
91	(394) Tools, Shop and Garage Equipment	35,368,851	2,646,096
92	(395) Laboratory Equipment	5,333,954	2,065
93	(396) Power Operated Equipment	60,529	
94	(397) Communication Equipment	336,498,609	50,992,592
95	(398) Miscellaneous Equipment	65,201,467	1,087,364
96	SUBTOTAL (Enter Total of lines 86 thru 95)	495,491,867	54,728,117
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)	495,491,867	54,728,117
100	TOTAL (Accounts 101 and 106)	15,576,853,691	1,279,013,706
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)	15,576,853,691	1,279,013,706

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
			191,341,267		4
			191,564,108		5
					6
					7
			14,526,518		8
			91,410,208		9
148,389			162,192,323		10
					11
			131,402,613		12
12,560			86,962,688		13
	-1,158,723		59,602,710		14
	5,149,533		5,259,070		15
160,949	3,990,810		551,356,130		16
					17
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					35
					36
			226,796		37
			24,812,767		38
			22,279,073		39
833,067			105,365,778		40
	371,318		366,763,275		41
38,932			33,767,456		42
			40,164,692		43
					44
871,999	371,318		593,379,837		45
1,032,948	4,362,128		1,144,735,967		46

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			252,442,567		48
962,749		4,511	669,356,121		49
3,694,376		-1,753,652	1,966,465,850		50
			922,725,564		51
17,928,525			930,750,214		52
5,447,019			821,798,414		53
			550,520,796		54
			557,705,658		55
			370,697,495		56
	1,391,376		928,663		57
28,032,669	1,391,376	-1,749,141	7,043,391,342		58
					59
			110,481,006		60
		-4,511	12,303,450		61
938,152		1,009,758	617,985,881		62
			125,965,956		63
17,767,917		950,735	941,396,761		64
3,966,590			974,345,978		65
2,036,926		-123	1,598,054,522		66
7,897,693	-2,574,099		1,763,177,307		67
8,321,793	498,664		752,621,931		68
1,625,742	50,363	-950,113	620,724,886		69
388,640			273,059,948		70
12,773		64,424,959	74,443,380		71
					72
63,582			34,064,775		73
	2,438,135		25,092,921		74
43,019,808	413,063	65,430,705	7,923,718,702		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			7,312,143		86
			45,611,646		87
					88
			58,146		89
			46,522		90
380,233			37,634,714		91
			5,336,019		92
			60,529		93
266,139		743,272	387,968,334		94
208,227		-62,875,737	3,204,867		95
854,599		-62,132,465	487,232,920		96
					97
					98
854,599		-62,132,465	487,232,920		99
72,940,024	6,166,567	1,549,099	16,790,643,039		100
					101
					102
					103
72,940,024	6,166,567	1,549,099	16,790,643,039		104

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

Reclassification of 2020 Electric Plant-in-Service for Ratemaking

Plant in Service Classified under FERC Seven Factor Test
In Accordance with Guidelines in FERC Order 888

	BOY 2020	EOY 2020	
Intangible Plant	176,890,080	191,341,265	
Steam Production Plant	556,350,443	561,761,598	
Nuclear Production Plant	-	-	*
Other Production Plant	524,898,411	537,020,375	
Transmission Plant	6,372,653,581	6,921,237,975	
Distribution Plant	7,414,162,678	8,046,663,231	
General Plant	495,491,863 -	487,232,916 -	
Ratemaking Electric	15,540,447,056	16,745,257,360	
ASC 410 (FAS 143 and FIN 47)	22,301,610	31,280,654	
Cuyamaca Permanent Adjustment	14,105,025	14,105,025	
Total Electric Plant-in-Service	15,576,853,691	16,790,643,039	

Total 13-Month Average Plant Balance for 2020 - Steam Production	557,045,050
Total 13-Month Average Plant Balance for 2020 - Other Production	529,465,617
Total 13-Month Average Plant Balance for 2020 - Transmission Plant	6,632,410,408

* As a result of the SONGS plant closure, the December 2020 Nuclear Production Plant Balance is zero.

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	Citizens Sunrise Transmission LLC	30 Mile-500KV Transmission Line	ER12-	07/02/2042	85,194,000
2		(Border-East Line)	686-000		
3					
4	Citizens Sycamore-Penasquitos	11.5 Mile-Underground 230KV	ER19-1513-	06/01/2049	27,000,000
5		Transmission Line (Segment B)	000 & ER19		
6			1513-001		
7					
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44					
45					
46					
47	TOTAL				112,194,000

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	04/16/2021	End of 2020/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
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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 $0.

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	1,224,388
2	TL628 CABLE REPLACEMENT	1,194,168
3	TL6916 POLE REPLACEMENT	1,726,474
4	SAN MARCOS SUB REBUILD 69KV & 12 KV	1,262,518
5	TL13831 WOOD TO STEEL REPLACEMENT	1,840,361
6	TL694 WOOD TO STEEL REPLACEMENT	1,951,237
7	TL698 WOOD TO STEEL REPLACEMENT	2,200,413
8	TL636 WOOD POLE REPLACEMENT	2,873,890
9	TL600 RELIABILITY POLE REPLACEMENTS	3,486,528
10	TL667 CABLE REPLACEMENT	1,799,007
11	GRANITE SUBSTATION 69KV LOOP-IN	2,179,963
12	POWAY SUBSTATION REBUILD	7,762,119
13	TL603B SWEETWATER TAP REMOVAL	2,630,084
14	TL692 WOOD TO STEEL REPLACEMENT	5,871,109
15	2ND 69KV LINE POMERADO TO POWAY	3,332,414
16	OVERSTRESSED BREAKER REPLACEMENTS	5,156,810
17	AERIAL MARKING FOR SAFETY	5,298,138
18	TL686 WARNERS-NARROWS POLE REPLACEMENT	5,211,361
19	TL674A RECONFIGURE	8,276,440
20	TL664 SOUTHBAY-SWEETWATER UPGRADE	4,591,173
21	TL691 WOOD TO STEEL REPLACEMENT	6,119,611
22	TL6975 ESCONDIDO - SAN MARCOS	6,530,981
23	TRANSMISSION SYSTEM AUTOMATION	9,145,644
24	MIGUEL SUB 230KV REBUILD	8,273,549
25	TL690 WOOD TO STEEL REPLACEMENT	7,147,670
26	TL673 CABLE REPLACE	9,220,544
27	TL695 SW POLE REPLACEMENT	8,315,839
28	TRANSMISSION SUBSTATION PROJECTS UNDER $500K	1,538,341
29	TL615/659 CABLE REPLACEMENT	8,211,642
30	SUBSTATION RELIABILITY UPGRADE PROJECT	4,770,568
31	TL6926 RINCON-VALLEY CENTER POLE REPLACEMENT	27,137,976
32	CONDITION BASED MONITORING - CIRCUIT BREAKERS	7,690,371
33	AVOCADO SUB 69KV REBUILD	16,925,699
34	SYNCHRONIZED PHASOR MEASUREMENT SYSTEM	18,000,370
35	MISSION 230KV REBUILD	32,769,727
36	TRANSMISSION PROJECTS UNDER $500K	7,870,257
37	CRITICAL ASSET SECURITY	8,251,369
38	TRANSMISSION INFRASTRUCTURE IMPROVEMENTS	18,813,402
39	FIBER OPTIC FOR RELAY PROTECTION & TELECOMMUNICATION	18,169,874
40	TRANSMISSION COMPLIANCE PROGRAM	22,735,412
41	FIRE THREAT ZONE COMPLIANCE PROGRAM	4,364,657
42	ESPOLA ROAD UG CONVERSION	2,551,960
43	TOTAL	1,101,637,518

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	04/16/2021	End of 2020/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	MELROSE SUBSTATION 12KV BREAKER REPLACEMENT	1,591,541
2	GRANITE SUBSTATION 12KV BREAKER REPLACEMENT	2,468,169
3	DRONE INVESTIGATION ASSESSMENT & REPAIR	17,333,627
4	CEMA EVENT - VALLEY FIRE	1,233,066
5	HEAVY DUTY VEHICLE CHARGING INFRASTRUCTURE	1,053,124
6	ENERGY STORAGE PROCUREMENT PLAN	1,091,740
7	POWER QUALITY PROGRAM	1,245,029
8	FALLBROOK BATTERY ENERGY STORAGE SYSTEM	1,343,169
9	TL639 POLE REPLACEMENT	1,345,783
10	URBAN SUBSTATION SWITCHGEAR REPLACEMENT	1,432,765
11	SCADA EXPANSION - TRANSMISSION	1,843,618
12	DESERT STAR ENERGY CENTER	1,916,742
13	CUSTOMER REQUESTED UPGRADES AND SERVICES	3,323,575
14	ARTESIAN 230KV SUBSTATION EXPANSION	72,646,580
15	TL663 MISSION-KEARNY RECONDUCTOR	1,216,532
16	ORANGE COUNTY LONG RANGE PLAN	163,019,709
17	CLEVELAND NATIONAL FOREST POLE REPLACEMENTS	35,853,344
18	TEE MODERNIZATION PROGRAM	1,455,852
19	4KV MODERNIZATION	2,563,493
20	HFTD FUSE REPLACEMENTS	3,185,906
21	DOE SWITCH REPLACEMENT	4,380,637
22	DISTRIBUTION SYSTEM CAPACITY IMPROVEMENT	2,578,271
23	REACTIVE SMALL CAPITAL PROJECTS	4,734,739
24	UG DISTRIBUTION SERVICE MANAGEMENT	2,022,126
25	DISTRIBUTION SUBSTATION RELIABILITY	2,998,451
26	PSPS ENGINEERING ENHANCEMENTS	9,233,568
27	SAN MATEO SUB REBUILD	3,093,609
28	CORRECTIVE MAINTENANCE PROGRAM	6,986,377
29	NEW BUSINESS INFRASTRUCTURE	3,270,017
30	OBSOLETE SUBSTATION EQUIPMENT REPLACEMENT	3,739,182
31	CORRECTIVE MAINT. PROG. (CMP) UG SWITCH REPLAC. & MANHOLE REPAIR	1,590,675
32	UG NON-RESIDENTIAL NEW BUSINESS	6,772,366
33	NEW SERVICE INSTALLATIONS	4,419,206
34	OH DISTRIBUTION SERVICE MANAGEMENT	5,744,601
35	SUBSTATION BREAKER AND RELAY REPLACEMENTS	9,302,126
36	WIRE SAFETY ENHANCEMENT	2,345,741
37	STREAMVIEW SUBSTATION 69/12KV REBUILD	6,912,239
38	UG RESIDENTIAL NEW BUSINESS	5,870,334
39	ELECTRIC DISTRIBUTION STREET & HIGHWAY RELOCATIONS	16,313,004
40	WOOD POLE REINFORCEMENT	8,796,287
41	RANCHO SANTA FE SUBSTATION FIRE HARDENING	18,147,663
42	HFTD TIER 2 & 3 CMP POLE REPLACEMENTS	11,360,287
43	TOTAL	1,101,637,518

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	04/16/2021	End of 2020/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	FIRE THREAT ZONE PROTECTION & SCADA UPGRADE	31,950,361
2	MOBILE HOME PARK UTILITY UPGRADES	10,464,157
3	POLE RISK MITIGATION	33,631,101
4	MIRAMAR ENERGY STORAGE	36,146,678
5	CONVERSION FROM OH TO UG RULE 20A	27,565,256
6	STRATEGIC FIRE HARDENING	105,053,801
7	ENERGIZED TEST YARD	2,249,915
8	PLANNED CABLE REPLACEMENTS	2,541,397
9	MIRAMAR PLANT OPERATIONAL ENHANCEMENTS	2,669,630
10	DISTRIBUTION CIRCUIT RELIABILITY CONSTRUCTION	2,729,811
11	BACKUP POWER FOR RESILIENCY	5,650,063
12	C1450, MTO:NEW 12 KV CIRCUIT	10,776,509
13	TRANSMISSION FIBER OPTIC NETWORK	14,506,227
14	FIRE THREAT ZONE UNDERGROUNDING	48,629,076
15	C303 RECONDUCTOR	1,091,617
16	UNALLOCATED CONSTRUCTION OVERHEADS & LABOR ACCRUAL	-44,178,988
17	MINOR PROJECTS (LESS THAN $1,000,000)	27,961,979
18		
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43	TOTAL	1,101,637,518

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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	5,190,286,178	5,167,252,015		23,034,163
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	559,252,781	559,252,781		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others	3,822,868			3,822,868
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)	563,075,649	559,252,781		3,822,868
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	72,940,024	72,940,024		
13	Cost of Removal	103,297,825	103,297,825		
14	Salvage (Credit)	690,784	690,784		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	175,547,065	175,547,065		
16	Other Debit or Cr. Items (Describe, details in footnote):	-63,468,555	-63,468,555		
17					
18	Book Cost or Asset Retirement Costs Retired	62,125,593	62,125,593		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,576,471,800	5,549,614,769		26,857,031
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	274,156,096	274,156,096		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	315,085,892	315,085,892		
25	Transmission	1,475,915,486	1,449,058,455		26,857,031
26	Distribution	3,313,713,768	3,313,713,768		
27	Regional Transmission and Market Operation				
28	General	197,600,558	197,600,558		
29	TOTAL (Enter Total of lines 20 thru 28)	5,576,471,800	5,549,614,769		26,857,031

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

Depreciation Provision - Electric Only (Line 10, Pg 219)	$	559,252,781
Depreciation Provision - Common Alloc. to Elec. (Line 11, Pg 336)		44,040,469
Depreciation Provision - (Line 6, Col. G, Pg 115)	$	603,293,250

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

Book Cost of Plant Retired (Line 12, Col. B, Pg 219)	$	(72,940,024)
Total Plant Retired (Line 100, Col. D, Pg 207)		72,940,024
Difference	$	0

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

SONGS Decommissioning - Current Year Trust Income (Loss)	$	(63,846,181)
Transfer of Reserve Balances between Departments		377,626
Other Debit and Credit Items (Line 16, Pg 219)	$	(63,468,555)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
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32				
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37				
38				
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40				
41				
42	Total Cost of Account 123.1 $ 0		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	04/16/2021	End of 2020/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
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				10
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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	04/16/2021	End of 2020/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	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)	122,595,800	131,950,322	ELECTRIC/GAS
6	Assigned to - Operations and Maintenance	8,885,855	9,563,880	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)	355,961	383,123	ELECTRIC/GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	131,837,616	141,897,325	
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)	131,837,616	141,897,325	

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

Reclassification of FERC Form 1 2020 Materials & Supplies, Page 227, for Ratemaking

Materials and Supplies Classified

In accordance with Guidelines in FERC Order 888

	EOY 2020	
Total Materials and Supplies (FERC 154)	141,897,325	1
As Assigned to Department for Ratemaking		
Electric Department	131,606,071	
Gas Department	10,291,254	
Total Allowable Materials and Supplies per FERC Formula	131,606,071	
Total 13-Month Average Electric M&S for 2020	128,917,247	2

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

[2] Ties to Line 1 of Cost Statement AL supporting workpaper, in TO5 Cycle 4 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	04/16/2021	End of 2020/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)	2021 No. (d)	2021 Amt. (e)
1	Balance-Beginning of Year	131,687.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	12,947.00		12,947.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Transfers to Palomar	-3.00			
10	Transfers to Miramar				
11	Transfers to Cuyamaca Pk				
12	Transfers to Desert Str	-4.00			
13					
14					
15	Total	-7.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	144,627.00		12,947.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						131,687.00		1
								2
								3
12,947.00		12,947.00		349,569.00		401,357.00		4
								5
								6
								7
								8
						-3.00		9
								10
								11
						-4.00		12
								13
								14
						-7.00		15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
12,947.00		12,947.00		349,569.00		533,037.00		29
								30
								31
								32
								33
								34
								35
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								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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)	2021 No. (d)	2021 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.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
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Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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)	Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
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					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
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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	04/16/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Taxes Recoverable in Rates	829,275,884	225,785,389	Various	121,921,202	933,140,071
2	Amortized Over Various Lives					
3						
4	Employer's Accounting for Postemployment Benefits	4,529,000	2,083,000			6,612,000
5						
6	Environmental Clean-Up	5,090,169	14,388,763	253	507,979	18,970,953
7						
8	Balancing Account Undercollections	925,535,387	140,984,823			1,066,520,210
9						
10	Pension Benefits	122,092,996		926	53,438,537	68,654,459
11						
12	SONGS Mitigation	39,684,546		253	2,752,666	36,931,880
13						
14	Electric Derivatives	109,773,223		244	34,678,228	75,094,995
15						
16	Contribution to City of Escondido	1,056,875		253	153,900	902,975
17	(20 year life, starting 2006)					
18						
19	Asset Retirement Obligations	24,328,648	2,942,645	Various	3,951,756	23,319,537
20						
21	Sunrise Wildfire Mitigation	120,672,994	812,989			121,485,983
22						
23	Beyond The Meter	27,304,586	9,266,472	232	3,801,993	32,769,065
24						
25	Unamortized Line of Credit (LOC) Net					
26						
27	Theoretical Withdrawal Premium OIL	12,656,807		253	263,028	12,393,779
28						
29	Post Retirement Benefits Other than Pension	439,015	1,034,035			1,473,050
30						
31	Worker's Compensation (Incurred But Not Recorded)		226,269			226,269
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	2,222,440,130	397,524,385		221,469,289	2,398,495,226

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Debt Issuance costs	819,496	905,386			1,724,882
2						
3	Southwest Powerlink Deferred	300,778		406	15,744	285,034
4	per CPUC					
5	(amortization 01/1986-12/2023)					
6						
7	Mitigation Fund	137,706				137,706
8						
9	Environmental Program	6,876,675	1,716,688	various	280,828	8,312,535
10						
11	Workers Comp Receivable	10,973,521	2,451,862	various	1,966,170	11,459,213
12						
13	SONGS Decommissioning	679,090		228	546,917	132,173
14						
15	Pendleton Energy Park	195,734				195,734
16						
17	Supervisory Control & Data	498,664	88,728	various	587,392	
18	Acquisition Equipment					
19						
20	SONGS Reg Asset Receivable	47,805,819		143	36,219,662	11,586,157
21						
22	PBOP Asset	19,633,840	452,034			20,085,874
23						
24	Surplus Material	5,323,403	614,399			5,937,802
25						
26	Airbus Helicopter Trade Account	462,000				462,000
27						
28	Wildfire Fund AB1054	391,820,469		various	28,879,968	362,940,501
29	(amortization 07/2019-07/2034)					
30						
31	Line of credit (LOC) fees		2,491,173			2,491,173
32						
33	Camp Pendleton Easement		517,000			517,000
34						
35	Miscellaneous Other	153,484	398	131	65,561	88,321
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	485,680,679				426,356,105

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	89,070,415	66,270,343
3	State	44,735,614	33,293,445
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	133,806,029	99,563,788
9	Gas		
10	Federal	6,201,175	5,393,701
11	State	3,249,674	3,058,219
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	9,450,849	8,451,920
17	Other (Specify) Non-Utiltity	410,784	410,776
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	143,667,662	108,426,484

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 $1,292,000.

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 $1,981,586.

The deferred tax asset related to FERC transmission on a stand-alone basis as of December 31, 2020, 2019, 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			
	2020	2019	2018	2017
FERC AC 190				
FERC - Remeasured Amount	$ 57	$ 119	$ 124	$ 162
FERC - Excess Reserve Protected	$ 107	$ 108	$ 109	$ 108
FERC - Excess Reserve Unprotected	$ -	$ -	$ -	$ -
Total	$ 164	$ 227	$ 233	$ 270

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

Schedule Page: 234 Line No.: 8 Column: b

Account 190 non-Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($227,471,476).

Account 190 Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($11,722,884).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the beginning of the year was ($1,787,644).

Schedule Page: 234 Line No.: 8 Column: c

Account 190 non-Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($164,013,239).

Account 190 Citizen transmission related deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($8,452,524).

Account 190 transmission related other deferred tax (asset) included in electric accumulated deferred income taxes at the end of the year was ($2,255,357).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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.			
10				
11				
12				
13				
14				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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
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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	04/16/2021	End of 2020/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	Wildfire Fund AB1054 initial contribution from Enova Corporation	322,500,000
11	Total Account 211	802,165,368
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40	TOTAL	802,165,368

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common	24,605,640
2		
3		
4		
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21		
22	TOTAL	24,605,640

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	6.125% Series FFF due 2037	250,000,000	2,556,327
21			780,000 D
22	6.000% Series GGG due 2039	300,000,000	3,057,571
23			1,380,000 D
24	5.350% Series HHH due 2040	250,000,000	2,486,955
25			335,000 D
26	4.500% Series III due 2040	500,000,000	5,044,008
27			5,515,000 D
28	3.000% Series JJJ due 2021	350,000,000	2,775,568
29			1,795,500 D
30	3.950% Series LLL due 2041	250,000,000	2,639,787
31			350,000 D
32	4.300% Series MMM due 2042	250,000,000	2,569,738
33	TOTAL	7,251,265,000	88,454,870

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			1,297,500 D
2	3.600% Series NNN due 2023	450,000,000	3,670,004
3			72,000 D
4	1.914% Series PPP due 2022	250,000,000	871,681
5			
6	2.500% Series QQQ due 2026	500,000,000	4,279,086
7			1,625,000 D
8	3.750% Series RRR due 2047	400,000,000	4,038,478
9			1,784,000 D
10	4.150% Series SSS due 2048	400,000,000	4,072,043
11			1,768,000 D
12	4.100% Series TTT due 2049	400,000,000	4,345,931
13			420,000 D
14	3.320% Series UUU due 2050	400,000,000	4,464,828
15			532,000 D
16	1.700% Series VVV due 2030 (D.18-02-012 and D.20-04-015 issued September 22, 2020)	800,000,000	6,789,739
17			1,392,000 D
18	TOTAL ACCOUNT 221	6,501,265,000	88,454,870
19			
20	ACCOUNT 224 - OTHER LONG-TERM DEBT		
21			
22	3.500% Line of Credit (LOC) Drawdown	750,000,000	
23	TOTAL ACCOUNT 224	750,000,000	
24			
25			
26			
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28			
29			
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31			
32			
33	TOTAL	7,251,265,000	88,454,870

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		2,458,603	4
						5
06/17/04	02/15/34	06/17/04	02/15/34		2,255,463	6
						7
06/17/04	02/15/34	06/17/04	02/15/34		1,973,239	8
						9
06/17/04	01/01/34	06/17/04	01/01/34		1,353,331	10
						11
06/17/04	01/01/34	06/17/04	01/01/34		1,896,844	12
						13
06/17/04	05/01/39	06/17/04	05/01/39		2,891,667	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
09/20/07	09/15/37	09/20/07	09/15/37	250,000,000	15,312,500	20
						21
05/14/09	06/01/39	05/14/09	06/01/39	300,000,000	18,000,000	22
						23
05/13/10	05/15/40	05/13/10	05/15/40	250,000,000	13,375,000	24
						25
08/26/10	08/15/40	08/26/10	08/15/40	500,000,000	22,500,000	26
						27
08/18/11	08/15/21	08/18/11	08/15/21	350,000,000	10,500,000	28
						29
11/17/11	11/15/41	11/17/11	11/15/41	250,000,000	9,875,000	30
						31
03/22/12	04/01/42	03/22/12	04/01/42	250,000,000	10,750,000	32
				6,053,573,000	233,778,584	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
09/09/13	09/01/23	09/09/13	09/01/23	450,000,000	16,200,000	2
						3
03/12/15	02/01/22	03/12/15	02/01/22	53,573,000	1,253,243	4
						5
05/19/16	05/15/26	05/19/16	05/15/26	500,000,000	12,500,000	6
						7
06/08/17	06/01/47	06/08/17	06/01/47	400,000,000	15,000,000	8
						9
05/17/18	05/15/48	05/17/18	05/15/48	400,000,000	16,600,000	10
						11
05/31/19	06/15/49	05/31/19	06/15/49	400,000,000	16,400,000	12
						13
04/07/20	04/15/50	04/07/20	04/15/50	400,000,000	9,738,667	14
						15
09/22/20	10/01/30	09/22/20	10/01/30	800,000,000	3,513,333	16
						17
				6,053,573,000	232,721,890	18
						19
						20
						21
03/16/20	04/08/20				1,056,694	22
					1,056,694	23
						24
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						31
						32
				6,053,573,000	233,778,584	33

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

Expense	$58,800,694
Discount	$20,458,500
Total	$79,259,194

Schedule Page: 256.1 Line No.: 19 Column: a

D.93-09-069 - At December 2020 total remaining authority for new preferred debt under this decision was $48,360,000.

D.04-01-009 - At December 2020 total remaining authority for new preferred debt under this decision was $4,000,000 and $76,000,000 for rollover preferred.

D.06-05-015 - At December 2020 total remaining authority for new preferred debt under this decision was $200,000,000.

D.08-07-029 - At December 2020 total remaining authority for rollover debt under this decision was $123,130,000.

D.10-10-023 - At December 2020 total remaining authority for new preferred debt under this decision was $150,000,000.

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 and $300,000,000 in rollover debt. In May 2019, SDG&E issued 4.1000% First Mortgage bond series TTT for $334,570,000 due 2049. In April 2020, SDG&E issued 3.3200% First Mortgage bond series UUU for $400,000,000 due 2050. In September 2020, SDG&E issued 1.7000% First Mortgage bond series VVV for $15,430,000. At December 2020 total remaining authority for rollover debt under this decision was $300,000,000.

D.20-04-015 - In April 2020, SDG&E received authority from the California Public Utilities Commission to issue $2,300,000,000 of new debt and $730,000,000 in rollover debt. In September 2020, SDG&E issued 1.7000% First Mortgage bond series VVV for $784,570,000 due 2030. At December 2020 total remaining authority for new debt under this decision was $1,515,430,000 and $730,000,000 for rollover debt.

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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)	824,492,862
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	72,405,388
6	SONGS Decommissioning Costs	53,387,596
7	Other (Itemized within footnote)	4,000
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation on Fixed Assets	783,436,820
11	Federal and State Taxes	190,397,944
12	Amortization and Interest Capitalized	82,153,707
13	Other (Itemized within footnote)	101,086,575
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	-103,595,672
16	Unbilled Revenue	-66,886,904
17	Restricted Stock	-9,496,535
18	Other (Itemized within footnote)	-19,363,623
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation on Fixed Assets	-588,822,285
21	Regulatory Balancing Accounts	-239,236,783
22	Repairs	-195,348,796
23	Software Development Costs	-172,644,815
24	Removal Costs	-117,794,432
25	Current State Tax Deduction	-27,652,377
26	Other (Itemized within footnote)	-44,476,325
27	Federal Tax Net Income	522,046,346
28	Show Computation of Tax:	
29	Federal Tax @ 21%	109,629,733
30	Deferred Taxes	31,221,603
31	Tax Credits and Other Adjustments (net)	10,173,627
32	Fed Discrete Taxes	1,163,447
33	Total Federal Income Tax Expense	131,841,156
34		
35		
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44		

Schedule Page: 261 Line No.: 1 Column: b

South Georgia Adjustment of $1,304,099 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.: 7 Column: b

Fuel Tax Credit Addback	$ 4,000
	4,000

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

Bad Debt	$ 53,617,360
Contingency Book Reserves	15,191,499
CARES Act Payroll tax deferral	20,580,000
Fringe Benefits	1,288,397
Lobbying	1,034,345
Penalties	5,591,200
Miscellaneous Expenses	3,783,774
	$ 101,086,575

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

Keyman Life Insurance	$ (7,555,514)
Deferred Construction Revenue	(7,266,412)
Reacquired Debt	(4,541,697)
	$ (19,363,623)

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

Facts & Circumstances Repairs	$ (25,167,864)
Property Taxes	(12,352,666)
Abandonment Loss	(5,396,872)
Miscellaneous Inc/(Ded)	(819,000)
Deferred Debits/Credits	(575,263)
SERP	(164,660)
	$ (44,476,325)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	LOCAL:					
2	Ad Valorem (Note 1)		1,434,577	164,559,140	182,602,678	-18,637,118
3	Sales and Use (Note 2)	26,818		328,278	342,864	
4	Business License			80,443	80,443	
5						
6	SUBTOTAL	26,818	1,434,577	164,967,861	183,025,985	-18,637,118
7						
8	STATE:					
9	Franchise (Note 3)		39,366,168	33,944,896	-5,416,342	490,931
10	Unemployment (Note 4)	1,472		872,811	725,774	
11	Sales and Use (Note 2)	64,489		1,125,528	1,175,532	
12	Fuel Tax	9,274		6,438	8,312	
13						
14	SUBTOTAL	75,235	39,366,168	35,949,673	-3,506,724	490,931
15						
16	FEDERAL:					
17	Taxes on Income (Note 3)		86,974,905	120,719,717	30,000,000	243,117
18	Retirement (Note 4)	313,876		42,699,747	32,255,380	
19	Unemployment (Note 4)	384		250,253	208,212	
20	Medicare (Note 4)	145,107		9,576,832	9,611,563	
21	Fuel Tax		9,749	106,657	192,651	
22						
23						
24	SUBTOTAL	459,367	86,984,654	173,353,206	72,267,806	243,117
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	561,420	127,785,399	374,270,740	251,787,067	-17,903,070

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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
	840,997	142,340,859			22,218,281	2
12,232					328,278	3
		74,921			5,522	4
						5
12,232	840,997	142,415,780			22,552,081	6
						7
						8
	495,861	41,331,754			-7,386,858	9
148,509		656,850			215,961	10
14,485					1,125,528	11
7,400					6,438	12
						13
170,394	495,861	41,988,604			-6,038,931	14
						15
						16
3,501,695		130,986,812			-10,267,095	17
10,758,243		12,792,913			29,906,834	18
42,425		188,333			61,920	19
110,376		2,869,229			6,707,603	20
	95,743				106,657	21
						22
						23
14,412,739	95,743	146,837,287			26,515,919	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
14,595,365	1,432,601	331,241,671			43,029,069	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

Property tax expense of $639,382 and $254,388 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines are deducted and moved to column (l).

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

Includes property tax expense of $639,382 and $254,388 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines.

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

Description	Adjustment Amount	FERC 190	FERC 283	FERC 171	FERC 237
Balance Sheet Reclassification Due to FIN 48 Liabilities	490,931		(490,931)		
Total - California Corporation Franchise Tax Adjustment	490,931	-	(490,931)	-	-

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

Description	Adjustment Amount	FERC 190	FERC 283	FERC 171	FERC 237
Utilization of Net Operating Loss					
Balance Sheet Reclassification Due to FIN 48 Liabilities	243,117		(243,117)		
Total - Federal Income Tax Adjustment	243,117	-	(243,117)	-	-

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

Payroll tax expense of $20,621 and $7,887 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines are deducted and moved to column (l).

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

Includes payroll tax expense of $20,621 and $7,887 associated with the Citizens portion of the Border-East and SX-PQ Segment B lines.

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.

Sales and Use tax adjustments in column "f" are to adjust carry forward balances from last year.

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	04/16/2021	End of 2020/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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		13,162,353			411.4	990,350	1,205,866
7							
8	TOTAL	13,162,353				990,350	1,205,866
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Utility Various	1,265,996			411.4	60,130	-1,205,866
11							
12							
13							
14							
15							
16							
17							
18							
19							
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41							
42							
43							
44							
45							
46							
47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
13,377,869	25 to 30 years		6
			7
13,377,869			8
			9
	25 to 30 years		10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			28
			30
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			33
			34
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			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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.

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	CIAC/CAC Tax Gross-Ups	63,718,705	456/495	13,443,056	18,277,929	68,553,578
2	Amortized over various 31 yr lives					
3						
4	SONGS Mitigation	38,810,806	182.3	3,477,895	371,450	35,704,361
5						
6	OIL Insurance Limited	12,656,806	182.3	263,028		12,393,778
7						
8	Sunrise Fire Mitigation Liability	117,099,089	182.3	3,645,383	4,386,895	117,840,601
9						
10	Citizens Lease	87,028,589	242	3,736,061		83,292,528
11						
12	Greenhouse Gas Obligations	61,732,079	158	131,107,461	69,375,382	
13						
14	Miscellaneous	25,174,453	Various	107,381,368	120,975,534	38,768,619
15						
16	Wildfire Fund	85,862,748	Various	13,060,530	2,086,890	74,889,108
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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41						
42						
43						
44						
45						
46						
47	TOTAL	492,083,275		276,114,782	215,474,080	431,442,573

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	04/16/2021	End of 2020/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
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							15
							16
							17
							18
							19
							20
							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) 04/16/2021	Year/Period of Report End of 2020/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	1,549,417,522	61,159,331	92,165,217
3	Gas	166,089,225	8,610,640	10,499,697
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,715,506,747	69,769,971	102,664,914
6				
7	Non Utility	56,100,445		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,771,607,192	69,769,971	102,664,914
10	Classification of TOTAL			
11	Federal Income Tax	1,453,718,226	53,381,227	87,725,905
12	State Income Tax	317,888,966	16,388,744	14,939,009
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	41,590,092	Various	100,330,282	1,577,151,826	2
		Various	6,071,993	Various	14,596,089	172,724,264	3
							4
			47,662,085		114,926,371	1,749,876,090	5
							6
7,310,761	454,815			182.3	22,133,846	85,090,237	7
							8
7,310,761	454,815		47,662,085		137,060,217	1,834,966,327	9
							10
5,144,973	454,815		33,926,836		92,924,649	1,483,061,519	11
2,165,788			13,735,249		44,135,568	351,904,808	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 non-Citizens transmission related excess deferred federal income taxes in the amount of ($4,566,795).

Account 282 electric balance at the beginning of the year reflects a reduction for (amortization) of Citizens transmission related excess deferred federal income taxes in the amount of ($180,826).

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $720,245,325.

Account 282 Citizens Sunrise transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $12,485,206.

Account 282 Citizens SX-PQ transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the beginning of the year was $2,872,340.

Account 282 non-Citizen transmission related excess deferred income tax reserve at the beginning of the year was $380,930,817.

Account 282 Citizen transmission related excess deferred income tax reserve at the beginning of the year was $8,498,838.

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 ($4,309,561).

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 ($180,826).

Account 282 non-Citizen transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $732,250,020.

Account 282 Citizens Sunrise transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $12,022,715.

Account 282 Citizens SX-PQ transmission related accumulated deferred income taxes included in electric accumulated deferred income taxes at the end of the year was $3,028,935.

Account 282 non-Citizen transmission related excess deferred income tax reserve at the end of the year was $376,621,256.

Account 282 Citizen transmission related excess deferred income tax reserve at the end of the year was $8,318,012.

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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		171,677,906	102,031,263	70,895,048
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	171,677,906	102,031,263	70,895,048
10	Gas			
11		15,506,069	8,880,947	4,420,511
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	15,506,069	8,880,947	4,420,511
18	Non-Utilities	30,149,609		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	217,333,584	110,912,210	75,315,559
20	Classification of TOTAL			
21	Federal Income Tax	149,194,975	79,320,639	54,968,946
22	State Income Tax	68,138,609	31,591,571	20,346,613
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		182.3	47,491,744	Various	68,399,017	223,721,394	3
							4
							5
							6
							7
							8
			47,491,744		68,399,017	223,721,394	9
							10
		182.3	10,413,904	Various	18,497,317	28,049,918	11
							12
							13
							14
							15
							16
			10,413,904		18,497,317	28,049,918	17
26,915	432,616	182.3	297,943	182.3	8,914,327	38,360,292	18
26,915	432,616		58,203,591		95,810,661	290,131,604	19
							20
26,915	304,455		39,817,117		65,285,094	198,737,105	21
	128,161		18,386,474		30,525,567	91,394,499	22
							23

NOTES (Continued)

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

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the beginning of the year was $5,987,514.

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

Account 283 transmission allocation related other deferred tax liability included in electric accumulated deferred income taxes at the end of the year was $7,906,429.

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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	937,311,572	Various	27,512,669	1,841,476	911,640,379
3						
4						
5	Asset Retirement Obligations	585,323,986	230	39,037,686	1,868,497	548,154,797
6						
7						
8	Balancing Account Overcollections	834,404,643	456/495	151,373,096	66,529,916	749,561,463
9						
10						
11	Electric / Gas Derivatives	102,088,395	175.1	578,767	26,780,133	128,289,761
12						
13						
14	PBOP Benefits	19,633,840			452,034	20,085,874
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	2,478,762,436		218,502,218	97,472,056	2,357,732,274

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	1,600,890,105	1,456,233,480
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,402,837,991	1,478,133,425
5	Large (or Ind.) (See Instr. 4)	358,553,421	394,124,985
6	(444) Public Street and Highway Lighting	14,272,909	14,246,864
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,376,554,426	3,342,738,754
11	(447) Sales for Resale	414,730,041	389,753,137
12	TOTAL Sales of Electricity	3,791,284,467	3,732,491,891
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,791,284,467	3,732,491,891
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	100,035,626	99,652,448
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	3,551,962	5,223,519
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	849,991,545	504,297,960
22	(456.1) Revenues from Transmission of Electricity of Others	271,027,123	302,746,348
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	1,224,606,256	911,920,275
27	TOTAL Electric Operating Revenues	5,015,890,723	4,644,412,166

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ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
6,606,155	5,981,976	1,311,290	1,298,976	2
				3
5,872,843	6,294,640	151,058	150,666	4
1,841,889	2,052,235	392	421	5
77,228	76,956	2,090	2,074	6
				7
				8
				9
14,398,115	14,405,807	1,464,830	1,452,137	10
10,344,942	9,822,599			11
24,743,057	24,228,406	1,464,830	1,452,137	12
				13
24,743,057	24,228,406	1,464,830	1,452,137	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	$ 91,351,964
Net Energy Metering	4,059,306
Service Establishment	2,809,830
Mover Service Charge	744,505
Late Payment Charge	150,041
Other*	483,436
	$100,035,626

* Individual balances are less than $250,000

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

Description

San Diego Franchise Fee Surcharge	$ 90,334,917
Net Energy Metering	4,213,988
Service Establishment	3,086,948
Mover Service Charge	744,505
Late Payment Charge	711,561
Other*	560,529
	$ 99,652,448

* Individual balances are less than $250,000

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

Includes Transmission Revenue Credits of $208,760

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

Includes Transmission Revenue Credits of $286,779

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

Description

Direct Access	$ 287,858,282
Cap and Trade Revenues	105,107,923
Balancing Accounts	385,160,293
CCA T&D Revenue	11,281,401
Federal Project Management	17,175,228
PUC Reimbursement Fee	13,015,817
CIAC Income Tax	6,006,110
LCFS Rec Credits	24,346,377
Shared Assets	3,802,823
Generation Trans. Interconnection Rev.	2,587,281
Unbilled Revenue	4,565,763
Government Turnkey	(16,044,837)
Employee Transfer Fees	567,500
Joint Pole Activity	3,589,710
Other*	971,874
	$ 849,991,545

* Individual balances are less than $250,000
* Includes Transmission Revenue Credits of $3,501,419

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

Description

Direct Access	$ 289,516,742
Cap and Trade Revenues	138,981,178
Balancing Accounts	34,085,211

CCA T&D Revenue	11,214,486
Federal Project Management	10,543,045
PUC Reimbursement Fee	9,790,548
CIAC Income Tax	5,733,677
LCFS Rec Credits	5,126,133
Shared Assets	3,840,189
Generation Trans. Interconnection Rev.	3,762,787
Unbilled Revenue	1,519,000
Litigation	(2,500,000)
Government Turnkey	(9,284,135)
Employee Transfer Fees	579,649
Joint Pole Activity	408,132
Other*	981,318
	$ 504,297,960

* Individual balances are less than $250,000
* Includes Transmission Revenue Credits of $4,811,079

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	DR	1,405,094	365,662,320	272,697	5,153	0.2602
2	DRTOU	4,255,309	1,058,615,018	891,778	4,772	0.2488
3	EVTOU	186,298	40,376,561	20,197	9,224	0.2167
4	DRLI	572,028	96,269,637	120,898	4,731	0.1683
5	DM	38,883	10,257,451	3,346	11,621	0.2638
6	DS	17,556	3,796,691	226	77,681	0.2163
7	DT	129,254	25,184,140	390	331,421	0.1948
8	OL-1	1,506	591,199	1,715	878	0.3926
9	DWL	227	137,088	43	5,279	0.6039
10	Total Residential Sales (440)	6,606,155	1,600,890,105	1,311,290	5,038	0.2423
11						
12	A	54,087	9,640,115	6,527	8,287	0.1782
13	ASTOD	1,581,834	391,881,790	119,676	13,218	0.2477
14	ATOU	277,610	61,665,204	901	308,113	0.2221
15	AD					
16	UM	13,361	3,339,960	128	104,383	0.2500
17	PA					
18	PAT1	296,098	49,227,306	3,934	75,266	0.1663
19	AL-TOU	3,495,790	850,493,942	14,386	242,999	0.2433
20	SPSS			4		
21	AY-TOU					
22	DG	35,511	9,686,357	251	141,478	0.2728
23	OL-1	4,621	1,406,972	1,609	2,872	0.3045
24	OLTOU	4,261	1,193,534	104	40,971	0.2801
25	TOUA	109,670	24,302,811	3,539	30,989	0.2216
26	Total Commercial (444)	5,872,843	1,402,837,991	151,059	38,878	0.2389
27						
28	DG		383,930			
29	AL-TOU	1,764,314	339,112,974	371	4,755,563	0.1922
30	A6-TOU	77,575	19,056,518	21	3,694,048	0.2457
31	Total Industrial (442)	1,841,889	358,553,422	392	4,698,696	0.1947
32						
33	LS1	15,882	5,319,431	781	20,335	0.3349
34	LS2	60,191	8,773,765	1,162	51,799	0.1458
35	LS3	1,155	179,712	147	7,857	0.1556
36	Total Public Street and Highway (	77,228	14,272,908	2,090	36,951	0.1848
37						
38						
39						
40						
41	TOTAL Billed	14,398,115	3,376,554,426	1,464,830	9,829	0.2345
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	14,398,115	3,376,554,426	1,464,830	9,829	0.2345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	California ISO					
2	City of Escondido (Rincon Hydro Plant)	SF	FERC Vol. 10			
3	Calpine Energy Services LP	SF	FERC Vol. 10			
4	City of Burbank	SF	FERC Vol. 10			
5	City of Glendale Water and Power	SF	FERC Vol. 10			
6	Citigroup Energy Inc	SF	FERC Vol. 10			
7	Clean Power Alliance of SoCal	SF	FERC Vol. 10			
8	Direct Energy Business Marketing	SF	FERC Vol. 10			
9	EDF Trading North America LLC	SF	FERC Vol. 10			
10	Los Angeles Dept. of Water & Power	SF	FERC Vol. 10			
11	Peninsula Clean Energy Authority	SF	FERC Vol. 10			
12	Powerex Corporation	OS	FERC Vol. 10			
13	Sacramento Municipal Utility District	SF	FERC Vol. 10			
14	Sonoma Clean Power Authority	SF	FERC Vol. 10			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Southern California Edison	SF	FERC Vol. 10			
2	TransAlta Energy Marketing US	SF	FERC Vol. 10			
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
9,532,979		378,949,450		378,949,450	1
87		14,605		14,605	2
	742,496			742,496	3
17,865		278,874		278,874	4
4,560		101,160		101,160	5
15		398		398	6
216,666	17,500	520,010	3,369,990	3,907,500	7
253,750		8,416,243	4,043,300	12,459,543	8
	653,306			653,306	9
19,400		408,340		408,340	10
236,000		7,605,765	3,426,600	11,032,365	11
400		6,200		6,200	12
62,420		2,129,126	936,285	3,065,411	13
	3,002,493			3,002,493	14
0	0	0	0	0	
10,344,942	4,509,295	398,444,571	11,776,175	414,730,041	
10,344,942	**4,509,295**	**398,444,571**	**11,776,175**	**414,730,041**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	93,500			93,500	1
800		14,400		14,400	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
10,344,942	4,509,295	398,444,571	11,776,175	414,730,041	
10,344,942	**4,509,295**	**398,444,571**	**11,776,175**	**414,730,041**	

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

Contract to sell Renewable Energy Credits (REC's)

Schedule Page: 310 Line No.: 8 Column: j

Contract to sell Renewable Energy Credits (REC's)

Schedule Page: 310 Line No.: 11 Column: j

Contract to sell Renewable Energy Credits (REC's)

Schedule Page: 310 Line No.: 13 Column: j

Contract to sell Renewable Energy Credits (REC's)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,071,055	2,153,989
5	(501) Fuel	85,839,459	93,885,412
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	357,033	301,885
10	(506) Miscellaneous Steam Power Expenses	6,566,199	6,529,345
11	(507) Rents	35,143	37,407
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	94,868,889	102,908,038
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	588	
16	(511) Maintenance of Structures	103,659	37,981
17	(512) Maintenance of Boiler Plant	2,359,936	2,646,843
18	(513) Maintenance of Electric Plant	352,104	-243,671
19	(514) Maintenance of Miscellaneous Steam Plant	4,795,725	9,063,286
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,612,012	11,504,439
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	102,480,901	114,412,477
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	9,300	176
25	(518) Fuel		
26	(519) Coolants and Water		310
27	(520) Steam Expenses		289
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses	3,463,925	4,574,915
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	3,473,225	4,575,690
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-177,358	157,983
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	12,232	4,307
38	(531) Maintenance of Electric Plant		1,896
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	-165,126	164,186
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	3,308,099	4,739,876
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	308,942	429,983
63	(547) Fuel	3,046,408	4,056,581
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses	5,092,124	3,670,501
66	(550) Rents		494
67	TOTAL Operation (Enter Total of lines 62 thru 66)	8,447,474	8,157,559
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	125,311	53,995
71	(553) Maintenance of Generating and Electric Plant	7,477,951	7,041,679
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	6,360,616	6,650,523
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	13,963,878	13,746,197
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	22,411,352	21,903,756
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,712,801,101	1,731,994,867
77	(556) System Control and Load Dispatching	2,165,143	2,767,950
78	(557) Other Expenses	5,914,678	6,496,622
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,720,880,922	1,741,259,439
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,849,081,274	1,882,315,548
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,646,021	7,279,011
84			
85	(561.1) Load Dispatch-Reliability	818,282	668,024
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,544,638	1,351,651
87	(561.3) Load Dispatch-Transmission Service and Scheduling	132,130	182,676
88	(561.4) Scheduling, System Control and Dispatch Services	5,200,324	5,093,244
89	(561.5) Reliability, Planning and Standards Development	82,101	94,124
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	2,022	2,098
92	(561.8) Reliability, Planning and Standards Development Services	3,058,271	3,079,738
93	(562) Station Expenses	6,458,357	6,283,709
94	(563) Overhead Lines Expenses	9,764,840	8,316,030
95	(564) Underground Lines Expenses	51,420	12,191
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	14,538,153	20,246,481
98	(567) Rents	2,779,304	2,829,825
99	TOTAL Operation (Enter Total of lines 83 thru 98)	51,075,863	55,438,802
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,772,731	2,017,028
102	(569) Maintenance of Structures	567,231	579,452
103	(569.1) Maintenance of Computer Hardware	857,038	1,248,578
104	(569.2) Maintenance of Computer Software	1,623,687	2,090,883
105	(569.3) Maintenance of Communication Equipment	65	103
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	156,270	143,700
107	(570) Maintenance of Station Equipment	15,716,966	16,048,173
108	(571) Maintenance of Overhead Lines	26,863,352	18,139,880
109	(572) Maintenance of Underground Lines	1,113,175	720,009
110	(573) Maintenance of Miscellaneous Transmission Plant	5,599	2,745
111	TOTAL Maintenance (Total of lines 101 thru 110)	48,676,114	40,990,551
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	99,751,977	96,429,353

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	3,171,002	3,090,662
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,171,002	3,090,662
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)	3,171,002	3,090,662
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	26,626,900	17,245,704
135	(581) Load Dispatching	2,959,973	2,509,902
136	(582) Station Expenses	6,583,947	4,697,978
137	(583) Overhead Line Expenses	12,787,071	7,555,815
138	(584) Underground Line Expenses	6,676,999	4,891,302
139	(585) Street Lighting and Signal System Expenses	652,415	630,794
140	(586) Meter Expenses	11,116,044	9,682,021
141	(587) Customer Installations Expenses	5,133,100	4,883,782
142	(588) Miscellaneous Expenses	61,840,999	39,442,661
143	(589) Rents	473,746	647,878
144	TOTAL Operation (Enter Total of lines 134 thru 143)	134,851,194	92,187,837
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,299,907	3,002,978
147	(591) Maintenance of Structures	170	330
148	(592) Maintenance of Station Equipment	4,389,418	3,134,766
149	(593) Maintenance of Overhead Lines	149,925,139	66,998,230
150	(594) Maintenance of Underground Lines	17,854,802	11,583,499
151	(595) Maintenance of Line Transformers	5,658	49,968
152	(596) Maintenance of Street Lighting and Signal Systems	220,135	145,088
153	(597) Maintenance of Meters	1,531,236	1,401,672
154	(598) Maintenance of Miscellaneous Distribution Plant	5,587,114	1,986,660
155	TOTAL Maintenance (Total of lines 146 thru 154)	181,813,579	88,303,191
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	316,664,773	180,491,028
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	766	54
160	(902) Meter Reading Expenses	2,075,012	2,419,017
161	(903) Customer Records and Collection Expenses	43,546,162	70,177,332
162	(904) Uncollectible Accounts	40,294,644	5,153,931
163	(905) Miscellaneous Customer Accounts Expenses	266,677	247,392
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	86,183,261	77,997,726

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		
168	(908) Customer Assistance Expenses	132,620,477	130,281,148
169	(909) Informational and Instructional Expenses	821,722	226,960
170	(910) Miscellaneous Customer Service and Informational Expenses	1,872,681	3,146,869
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	135,314,880	133,654,977
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	157,477	
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	157,477	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	46,411,109	31,012,001
182	(921) Office Supplies and Expenses	28,861,000	16,773,404
183	(Less) (922) Administrative Expenses Transferred-Credit	18,872,382	13,569,700
184	(923) Outside Services Employed	108,535,259	90,245,647
185	(924) Property Insurance	8,310,402	8,305,622
186	(925) Injuries and Damages	181,130,339	140,446,405
187	(926) Employee Pensions and Benefits	62,304,380	54,077,224
188	(927) Franchise Requirements	130,506,765	127,615,791
189	(928) Regulatory Commission Expenses	27,995,793	22,402,325
190	(929) (Less) Duplicate Charges-Cr.	2,772,785	2,181,084
191	(930.1) General Advertising Expenses	-204,155	112,529
192	(930.2) Miscellaneous General Expenses	2,511,055	2,206,682
193	(931) Rents	10,939,305	8,564,242
194	TOTAL Operation (Enter Total of lines 181 thru 193)	585,656,085	486,011,088
195	Maintenance		
196	(935) Maintenance of General Plant	9,293,298	12,341,892
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	594,949,383	498,352,980
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,085,274,027	2,872,332,274

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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.

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

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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	0.00000	0.00000	0.00000
2	California ISO			0.00000	0.00000	0.00000
3	Calipatria LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
4	Calpeak Power LLC	OS		0.00000	0.00000	0.00000
5	Campo Verde Solar LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
6	Carlsbad Energy Center LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
7	Cascade Solar LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
8	Catalina Solar LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
9	Centinela Solar Energy LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
10	Centinela Solar Energy 2 LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
11	City of Escondido (Bear Valley Hydro)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
12	City of Oceanside (San Francisco Peak	LU	FERC Vol. 10	0.00000	0.00000	0.00000
13	Clean Power Alliance of SoCal	LU	FERC Vol. 10	0.00000	0.00000	0.00000
14	Coram Energy LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
	Total					

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1	CP Kelco US Inc	LU	FERC Vol. 10	0.00000	0.00000	0.00000
2	CSolar IV South LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
3	CSolar IV West LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
4	Desert Green Solar Farm LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
5	El Cajon Energy Center (Tolling)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
6	Energia Sierra Juarez US LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
7	Escondido Energy Center LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
8	Goal Line LP	LU	FERC Vol. 10	0.00000	0.00000	0.00000
9	Grossmont Hospital Corporation	LU	FERC Vol. 10	0.00000	0.00000	0.00000
10	HL Power Company LP	LU	FERC Vol. 10	0.00000	0.00000	0.00000
11	Imperial Valley Solar I LLC (Mount Sig	LU	FERC Vol. 10	0.00000	0.00000	0.00000
12	Kumeyaay Wind LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
13	Manzana Wind LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
14	Maricopa West Solar PV LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
	Total					

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1	Midway Solar	LU	FERC Vol. 10	0.00000	0.00000	0.00000
2	MM Prima Deshecha Energy LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
3	MM San Diego LLC (Miramar RAM)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
4	Morgan Stanley Capital Group	LU	FERC Vol. 10	0.00000	0.00000	0.00000
5	Naturener Glacier Wind Energy 1 LLC	EX		0.00000	0.00000	0.00000
6	Naturener Glacier Wind Energy 2 LLC	EX		0.00000	0.00000	0.00000
7	Naturener Rim Rock Wind Energy LLC	EX		0.00000	0.00000	0.00000
8	NLP Valley Center Solar LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
9	NLP Granger A82 LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
10	Oak Creek Wind Power LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
11	Oasis Power Partners LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
12	Ocotillo Express LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
13	Olivenhain Muni Water District	LU	FERC Vol. 10	0.00000	0.00000	0.00000
14	Orange Grove Energy Center (Tolling)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
	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) 04/16/2021	Year/Period of Report End of 2020/Q4

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1	Otay Landfill Gas I	LU	FERC Vol. 10	0.00000	0.00000	0.00000
2	Otay Landfill Gas II	LU	FERC Vol. 10	0.00000	0.00000	0.00000
3	Otay Landfill Gas V	LU	FERC Vol. 10	0.00000	0.00000	0.00000
4	Otay Landfill Gas VI	LU	FERC Vol. 10	0.00000	0.00000	0.00000
5	Otay Mesa Energy Center (Tolling)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
6	Pacific Wind Lessee LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
7	Pio Pico Energy Center	LU	FERC Vol. 10	0.00000	0.00000	0.00000
8	San Diego County Water Authority -Oliv	LU	FERC Vol. 10	0.00000	0.00000	0.00000
9	San Gorgonio Westwinds II LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
10	San Marcos Energy LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
11	SG2 Imperial Valley LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
12	Sol Orchard 20 LLC (Ramona 1)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
13	Sol Orchard 21 LLC (Ramona 2)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
14	Sol Orchard 22 LLC (Valley Center 1)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	Sol Orchard 23 LLC (Valley Center 2)	LU	FERC Vol. 10	0.00000	0.00000	0.00000
2	Solar Borrego LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
3	Sycamore Energy 1 LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
4	Sycamore Energy 2 LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
5	Tallbear Seville LLC	LU	FERC Vol. 10	0.00000	0.00000	0.00000
6	Yuma Co-generator Association	LU	FERC Vol. 10	0.00000	0.00000	0.00000
7	3 Phases Renewables	SF	FERC Vol. 10	0.00000	0.00000	0.00000
8	BP Energy Company	SF	FERC Vol. 10	0.00000	0.00000	0.00000
9	California Choice Energy Authority	SF	FERC Vol. 10	0.00000	0.00000	0.00000
10	Calpine Energy Services	SF	FERC Vol. 10	0.00000	0.00000	0.00000
11	Citigroup Energy Inc	SF	FERC Vol. 10	0.00000	0.00000	0.00000
12	Elk Hills Power, LLC	SF	FERC Vol. 10	0.00000	0.00000	0.00000
13	Gateway Energy Storage, LLC	SF	FERC Vol. 10	0.00000	0.00000	0.00000
14	Los Angeles DWP	SF	FERC Vol. 10	0.00000	0.00000	0.00000
	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	04/16/2021	End of 2020/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	Macquarie Energy LLC	SF	FERC Vol. 10	0.00000	0.00000	0.00000
2	Marin Clean Energy	SF	FERC Vol. 10	0.00000	0.00000	0.00000
3	Pacific Gas & Electric Co.	SF	FERC Vol. 10	0.00000	0.00000	0.00000
4	Pioneer Community Energy	SF	FERC Vol. 10	0.00000	0.00000	0.00000
5	Portland General Electric Co.	SF	FERC Vol. 10	0.00000	0.00000	0.00000
6	Powerex Corporation	SF	FERC Vol. 10	0.00000	0.00000	0.00000
7	SAAVI Energy Solutions	SF	FERC Vol. 10	0.00000	0.00000	0.00000
8	Sempra Gas & Power Marketing LLC	SF	FERC Vol. 10	0.00000	0.00000	0.00000
9	Southern California Edison Company	SF	FERC Vol. 10	0.00000	0.00000	0.00000
10	Procurement software			0.00000	0.00000	0.00000
11	Other expense: Price & Load Forecastin			0.00000	0.00000	0.00000
12	Broker Fees	OS		0.00000	0.00000	0.00000
13	Hedging Activity	OS		0.00000	0.00000	0.00000
14	Columbia Power Consulting	OS		0.00000	0.00000	0.00000
	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	GHG Allowances	OS		0.00000	0.00000	0.00000
2	Procurement-related teleconferences	OS		0.00000	0.00000	0.00000
3	Misc. Adjustment			0.00000	0.00000	0.00000
4	Counterparty Deposits			0.00000	0.00000	0.00000
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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) 04/16/2021	Year/Period of Report End of 2020/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
374,999				43,248,857	1,555,146	44,804,003	1
15,335,793				696,040,425	-37,161,158	658,879,267	2
49,137			17,250	3,367,041	258,569	3,642,860	3
			3,705,027			3,705,027	4
347,662				40,748,912	992,335	41,741,247	5
405,011			101,626,144	19,717,037		121,343,181	6
56,218				4,434,592	-5,033	4,429,559	7
250,684				33,640,586	-24,624	33,615,962	8
381,171				51,295,813	1,705,520	53,001,333	9
134,998				17,811,683	465,388	18,277,071	10
1,513			17,015	42,588		59,603	11
217			2,527	7,731		10,258	12
			147,302			147,302	13
27,712				2,800,924	-2,775	2,798,149	14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
12,027			140,567	372,074		512,641	1
300,362				39,981,534	1,657,997	41,639,531	2
404,765				43,692,714	808,541	44,501,255	3
13,680				1,908,186	-1,367	1,906,819	4
6,355			7,282,812	506,680		7,789,492	5
443,752				42,840,593	2,278,779	45,119,372	6
12,872			7,674,106	765,808		8,439,914	7
21,356			11,255,269	827,403		12,082,672	8
3,142			20,917	106,223		127,140	9
187,642				20,476,234		20,476,234	10
412,183				47,195,104	1,242,335	48,437,439	11
158,313			-1,837	7,426,918	833,525	8,258,606	12
256,065				16,695,620		16,695,620	13
41,675				2,741,428	-3,205	2,738,223	14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
44,591			-93	1,940,975	365,774	2,306,656	1
45,641				1,304,870		1,304,870	2
27,076				2,357,822		2,357,822	3
855,741				35,192,701		35,192,701	4
	300,002	300,002		6,300,037		6,300,037	5
	318,314	318,314		9,549,404		9,549,404	6
	705,553	705,553		31,037,310		31,037,310	7
5,861				644,970	-495	644,475	8
7,284				807,447	-606	806,841	9
5,542				303,600	-497	303,103	10
				47,792		47,792	11
540,803				56,684,685	32,843	56,717,528	12
706				98,641		98,641	13
17,719			16,948,507	602,343		17,550,850	14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				15,000		15,000	1
				10,000		10,000	2
				10,000		10,000	3
				10,000		10,000	4
			42,626,242	3,861,974		46,488,216	5
289,204				33,388,596	-28,461	33,360,135	6
102,775			66,851,758	4,136,647		70,988,405	7
-17,996			2,757,878	218,475		2,976,353	8
35,432				2,421,904	-3,527	2,418,377	9
12,489			13,736	1,459,590		1,473,326	10
402,966			190,500	36,256,460	1,671,478	38,118,438	11
4,338				582,183	-430	581,753	12
8,794				1,202,256	-857	1,201,399	13
5,867				788,625	-585	788,040	14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

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)	
11,671				1,581,703	-1,161	1,580,542	1
69,167				9,471,617	501,708	9,973,325	2
6,993			-367	827,786		827,419	3
18,639			1,888	1,600,891		1,602,779	4
67,758			-611	4,953,100	490,802	5,443,291	5
108,528			10,130,871	4,027,842		14,158,713	6
			256,000			256,000	7
9,826				418,418		418,418	8
			18,125			18,125	9
			1,405,036			1,405,036	10
5,925				218,588		218,588	11
			226,237			226,237	12
			60,967			60,967	13
			184,680			184,680	14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
20,000				840,000		840,000	1
			57,484			57,484	2
			1,020,000			1,020,000	3
			326,593			326,593	4
9,995				414,793		414,793	5
184,242				13,923,472		13,923,472	6
			14,651,708	1,331,993		15,983,701	7
			4,247,152	17,766		4,264,918	8
			108,500			108,500	9
					24,000	24,000	10
					33,750	33,750	11
					193,548	193,548	12
					4,769,641	4,769,641	13
					32,400	32,400	14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

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)	
					26,786,458	26,786,458	1
					10,474	10,474	2
					-3	-3	3
					-200,000	-200,000	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
22,546,881	1,323,869	1,323,869	293,969,890	1,409,554,984	9,276,227	1,712,801,101	

Schedule Page: 326 Line No.: 1 Column: l
Curtailment of 13,621 MWh and payment/penalties of $1,460,660.56. Forecasting fees.

Schedule Page: 326 Line No.: 2 Column: l
CAISO allocated revenues and charges.

Schedule Page: 326 Line No.: 3 Column: l
Curtailment of 4,947 MWh and payment/penalties of $260,401. Forecasting fees.

Schedule Page: 326 Line No.: 5 Column: l
Curtailment of 11,489 MWh and payment/penalties of $1,176,732. Forecasting fees.

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

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

Schedule Page: 326 Line No.: 9 Column: l
Curtailment of 13,287 MWh and payment/penalties of $1,624,398. Forecasting fees.

Schedule Page: 326 Line No.: 10 Column: l
Curtailment of 3,884 MWh and payment/penalties of $447,652. Forecasting fees.

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

Schedule Page: 326.1 Line No.: 2 Column: l
Curtailment of 16,564 MWh and payment/penalties of $1,811,794. Forecasting fees.

Schedule Page: 326.1 Line No.: 3 Column: l
Curtailment of 14,535 MWh and payment/penalties of $1,305,156. Forecasting fees.

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

Schedule Page: 326.1 Line No.: 6 Column: l
Curtailment of 27,184 MWh and payment/penalties of $2,500,108. Forecasting fees.

Schedule Page: 326.1 Line No.: 11 Column: l
Curtailment of 13,584 MWh and payments/penalties of $1,179,078. Forecasting fees.

Schedule Page: 326.1 Line No.: 12 Column: l
Curtailment of 14,787 MWh and payment/penalties of $618,455. Forecasting fees. Resource Adequacy Payments.

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

Schedule Page: 326.2 Line No.: 1 Column: l
Curtailment of 7,596 MWh and payment/penalties of $357,451. Forecasting fees.

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

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

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

Schedule Page: 326.2 Line No.: 12 Column: l
Curtailment of 952 MWh and payments/penalties of $100,622. Forecasting fees.

Schedule Page: 326.3 Line No.: 6 Column: l
Curtailment of 6 MWh and payments/penalties of $414. Forecasting fees.

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

Schedule Page: 326.3 Line No.: 11 Column: l
Curtailment of 7,870 MWh and payments/penalties of $1,671,478.

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

Schedule Page: 326.3 Line No.: 13 Column: l
Forecasting fees.

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

Forecasting fees.

Schedule Page: 326.4 Line No.: 1 Column: l

Forecasting fees.

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

Curtailment of 4,167 MWh and payment/penalties of $508,822. Forecasting fees.

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

Curtailment of 9,347 MWh and payments/penalties of $492,721. Forecasting fees.

Schedule Page: 326.5 Line No.: 10 Column: l

Software & support

Schedule Page: 326.5 Line No.: 11 Column: l

Preparation/Analysis of a Price & Load Forecasting Review

Schedule Page: 326.5 Line No.: 12 Column: l

Contract administration expenses.

Schedule Page: 326.5 Line No.: 13 Column: l

Contract hedging activity.

Schedule Page: 326.5 Line No.: 14 Column: l

Engineering services.

Schedule Page: 326.6 Line No.: 1 Column: l

Amortization of GHG Allowances.

Schedule Page: 326.6 Line No.: 2 Column: l

Procurement-related teleconferences

Schedule Page: 326.6 Line No.: 3 Column: l

EPA activity

Schedule Page: 326.6 Line No.: 4 Column: l

Retained counterparty deposits

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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			

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)	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	04/16/2021	End of 2020/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.
	269,041,871		269,041,871	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	**269,041,871**	**0**	**269,041,871**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	907,764
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	-1,587,547
6	Abandoned Projects	2,360,718
7	Cost of Financing	2,973,260
8	FERC Audit Correction	-690,767
9	Abandoned Projects Adjustment	-1,452,373
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	2,511,055

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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			15,369,576		15,369,576
2	Steam Production Plant	24,313,379				24,313,379
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	25,567,018				25,567,018
7	Transmission Plant	201,026,445			1,947,809	202,974,254
8	Distribution Plant	283,537,190			2,009,779	285,546,969
9	Regional Transmission and Market Operation					
10	General Plant	24,808,749				24,808,749
11	Common Plant-Electric	44,040,469		54,474,070		98,514,539
12	TOTAL	603,293,250		69,843,646	3,957,588	677,094,484

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	04/16/2021	End of 2020/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	29,360					
14	311-Palomar	61,951					
15	312-Desert Star	54,576					
16	312-Palomar	107,510					
17	314-Desert Star	15,644					
18	314-Palomar	116,373					
19	315-Desert Star	49,277					
20	315-Palomar	37,256					
21	316-Desert Star	5,157					
22	316-Palomar	51,301					
23	SUBTOTAL	528,405					
24							
25	OTHER PRODUCTION						
26	341-CPEP	1,885					
27	341-Desert Star	2,043					
28	341-Miramar	5,076					
29	341-Palomar	14,821					
30	342-CPEP	627					
31	342-Desert Star	878					
32	342-Miramar	5,233					
33	342-Palomar	14,914					
34	343-CPEP	16,862					
35	343-Desert Star	24,351					
36	343-Miramar	53,600					
37	343-Palomar						
38	344-CPEP	2,829					
39	344-Desert Star	108,119					
40	344-Miramar	19,736					
41	344-Palomar	172,886					
42	344-Solar	59,689					
43	344-Wind	257					
44	345-CPEP	834					
45	345-Desert Star	9,390					
46	345-Miramar	13,461					
47	345-Palomar	6,706					
48	345-Solar	2,316					
49	345-Wind						
50	(continued)						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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-CPEP	3,821					
13	346-Desert Star	22,342					
14	346-Miramar	6,865					
15	346-Palomar	1,831					
16	SUBTOTAL	571,372					
17							
18	TRANSMISSION-SWPL						
19	352	35,654	74.00	-75.00	2.18	R2.5	54.60
20	353	286,974	50.00	-70.00	3.49	R1.5	40.60
21	354	50,744	70.00	-75.00	2.02	R5	36.50
22	355	7,337	45.00	-100.00	3.40	R1.5	25.50
23	356	39,796	64.00	-100.00	1.42	R2	38.40
24	359	5,468	60.00		1.51	SQ	31.60
25	SUBTOTAL	425,973					
26							
27	TRANSMISSION-SRPL						
28	352	151,422	74.00	-75.00	2.41	R2.5	68.80
29	353	203,803	50.00	-70.00	3.48	R1.5	45.60
30	354	958,269	70.00	-75.00	2.57	R5	64.50
31	355	4,317	45.00	-100.00	4.51	R1.5	40.50
32	356	219,570	64.00	-100.00	3.22	R2	58.80
33	357	91,388	60.00	-30.00	2.20	R5	54.50
34	358	132,178	50.00	-10.00	2.19	R2	45.10
35	359	227,323	60.00		1.66	SQ	54.50
36	SUBTOTAL	1,988,270					
37							
38	TRANSMISSION-OTHER						
39	352	525,236	74.00	-75.00	2.37	R2.5	67.90
40	353	1,456,769	50.00	-70.00	3.49	R1.5	43.50
41	353.4	1,509	50.00	-70.00	3.64	R1.5	40.10
42	354	64,436	70.00	-75.00	2.36	R5	48.90
43	355	810,206	45.00	-100.00	4.57	R1.5	39.80
44	356	525,241	64.00	-100.00	3.03	R2	53.80
45	357	408,719	60.00	-30.00	2.14	R5	52.00
46	358	406,801	50.00	-10.00	2.13	R2	43.50
47	359	105,399	60.00		1.69	SQ	52.80
48	SUBTOTAL	4,304,316					
49							
50	(continued)						

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	DISTRIBUTION						
13	361	10,334					
14	362.1	610,350					
15	363	126,260					
16	364	883,089					
17	365	900,019					
18	366	1,468,041					
19	367	1,753,376					
20	368.1	702,382					
21	368.2	31,718					
22	369.1	215,330					
23	369.2	384,492					
24	370.1	6,958					
25	370.11	195,805					
26	370.2	8,265					
27	370.21	57,999					
28	371	9,894					
29	371.1	18,781					
30	373.2	33,575					
31	SUBTOTAL	7,416,668					
32							
33	GENERAL						
34	390	45,612					
35	392.2	58					
36	393.1	47					
37	394.11	35,974					
38	394.2	278					
39	395.1	5,335					
40	397.1	332,883					
41	397.2	8,168					
42	397.6	14,131					
43	397.7	882					
44	398.1	7,098					
45	398.2						
46	SUBTOTAL	450,466					
47							
48	TOTAL	15,685,470					
49							
50	See footnote						

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

Reclassification of 2020 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	-	15,369,576	-	15,369,576
Steam Production	24,814,835	-	-	24,814,835
Nuclear Production	-	-	-	-
Other Production	23,851,103	-	-	23,851,103
Transmission Plant	198,782,421	-	1,937,023	200,719,444
Distribution Plant	286,995,673	-	2,020,565	289,016,238
General Plant	24,808,749	-	-	24,808,749
Common Plant-Electric	44,040,469	54,474,070	-	98,514,539
Total Ratemaking Electric Depreciation & Amort(1)	603,293,250	69,843,646	3,957,588	677,094,484

(1) Ties to Line 12 of FERC Form 1, page 336

Schedule Page: 336.2 Line No.: 50 Column: a

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

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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. 19-12-050 RESIDENTIAL RATE DESIGN		39,329	39,329	
2					
3	D. 19-12-052 RESIDENTIAL RATE DESIGN		6,492	6,492	
4					
5	D. 19-12-053 EXAMINATION OF RESIDENTIAL RATE S		18,702	18,702	
6					
7	D. 19-12-054 ALTERNATIVE-FUELED VEHICLE		3,344	3,344	
8					
9	D. 20-01-016 DISTRIBUTED ENERGY & RULE 21		3,832	3,832	
10					
11	D. 20-01-017 EXAMINATION OF IOU RATE		13,721	13,721	
12					
13	D. 20-01-018 Authority to Implement Economic s		21,317	21,317	
14					
15	D. 20-01-019 Electric IRP & LT Procurement Pls		6,382	6,382	
16					
17	D. 20-01-020 Electric IRP & LT Procurement Pls		4,299	4,299	
18					
19	D. 20-02-020 Authority to Implemet Economic Ds		22,540	22,540	
20					
21	D. 20-02-022 Electric IRP & LT Procurement Pls		19,643	19,643	
22					
23	D. 20-02-059 California Renewables Portfolio m		2,471	2,471	
24					
25	D. 20-02-062 San Onofre Nuclear Generating Sts		26,126	26,126	
26					
27	D. 20-02-063 Distributed Energy Resources		5,473	5,473	
28					
29	D. 20-02-065 Electric Utility Wildfire Mitigas		10,258	10,258	
30					
31	D. 20-02-066 Electric IRP & LT Procurement Pls		14,287	14,287	
32					
33	D. 20-04-017 De-Energization of Powerlines ins		2,281	2,281	
34					
35	D. 20-04-020 Energy Efficiency Rolling Portfon		5,867	5,867	
36			679	679	
37					
38	D. 20-04-021 2007 Southern Califonia Wildfirey		14,225	14,225	
39					
40	D. 20-04-023 Economic Development Rates		22,514	22,514	
41					
42	D. 20-04-024 Energy Savings Assistance & Altes		1,494	1,494	
43			173	173	
44					
45	D. 20-04-026 Energy Savings Assistance & Altes		1,993	1,993	
46	TOTAL	16,020,239	18,103,850	34,124,089	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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			277	277	
2					
3	D. 20-05-015 Update Revenue Requirement & Bass		4,597	4,597	
4			532	532	
5					
6	D. 20-05-016 Energy Efficiency Rolling Portfos		14,590	14,590	
7			2,163	2,163	
8					
9	D. 20-05-018 Safety Mosdel Assessment Review		6,610	6,610	
10			765	765	
11					
12	D. 20-05-031 Medium & Heavy Duty EV & Vehiclet		18,000	18,000	
13					
14	D. 20-05-032 Net Energy Metering Successor		9,845	9,845	
15					
16	D. 20-05-033 Medium & Heavy Duty EV & Vehiclet		116,552	116,552	
17					
18	D. 20-05-034 Medium & Heavy Duty EV & Vehiclet		60,603	60,603	
19					
20	D. 20-05-047 Electric IRP & LT Procurement Pls		6,115	6,115	
21					
22	D. 20-05-048 Energy Efficiency Rolling Portfon		1,643	1,643	
23			190	190	
24					
25	D. 20-05-049 Medium & Heavy Duty EV & Vehiclet		79,462	79,462	
26					
27	D. 20-05-050 Electric IRP & LT Procurement Pls		74,152	74,152	
28					
29	D. 20-06-008 California Renewables Portfolio m		10,559	10,559	
30					
31	D. 20-06-010 2020 Cost of Capital Operations m		19,113	19,113	
32			2,833	2,833	
33					
34	D. 20-06-011 Medium & Heavy Duty EV & Vehiclet		18,039	18,039	
35					
36	D. 20-06-012 Advanced Meter Data Incorporatios		21,589	21,589	
37					
38	D. 20-06-013 Medium & Heavy Duty EV & Vehiclet		51,066	51,066	
39					
40	D. 20-06-016 EV Charging Pilots for Schools &s		4,006	4,006	
41					
42	D. 20-06-039 EV Charging Pilots for Schools &s		4,172	4,172	
43					
44	D. 20-06-040 Electric IRP & LT Procurement Pls		8,393	8,393	
45					
46	TOTAL	16,020,239	18,103,850	34,124,089	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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. 20-06-043 Non-Bypassable California Wildfie		2,904	2,904	
2					
3	D. 20-06-044 Non-Bypassable California Wildfie		10,222	10,222	
4					
5	D. 20-06-045 Non-Bypassable California Wildfie		3,386	3,386	
6					
7	D. 20-06-046 De-Energization of Powerlines ins		6,111	6,111	
8					
9	D. 20-06-047 De-Energization of Powerlines ins		2,433	2,433	
10					
11	D. 20-06-048 De-Energization of Powerlines ins		8,463	8,463	
12					
13	D. 20-06-049 Residential Rate Design Window		23,233	23,233	
14					
15	D. 20-06-050 Residential Rate Design Window		23,727	23,727	
16					
17	D. 20-06-051 Wildfire Cost Recovery Critera &y		3,246	3,246	
18					
19	D. 20-07-025 Energy Efficiency Issues		1,269	1,269	
20			188	188	
21					
22	D. 20-07-026 Energy Efficiency Issues		5,631	5,631	
23			652	652	
24					
25	D. 20-07-027 Wildfire Cost Recovery Criteria y		1,926	1,926	
26					
27	D. 20-07-028 Wildfire Cost Recovery Criteria y		28,691	28,691	
28					
29	D. 20-07-029 EXAMINATION OF IOU RESIDENTIAL S		4,363	4,363	
30					
31	D. 20-07-030 Electric & Gas Revenue Requiremee		106,230	106,230	
32			12,294	12,294	
33					
34	D. 20-07-031 Electric & Gas Revenue Requiremee		134,742	134,742	
35			15,593	15,593	
36					
37	D. 20-08-009 De-Energization of Powerlines ins		4,671	4,671	
38					
39	D. 20-08-010 Electric & Gas Revenue Requiremee		560,540	560,540	
40			64,870	64,870	
41					
42	D. 20-08-041 Electric & Gas Revenue Requiremee		8,276	8,276	
43			958	958	
44					
45	D. 20-09-006 Rate Relief and Increase Spend i.		50,217	50,217	
46	TOTAL	16,020,239	18,103,850	34,124,089	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1					
2	D. 20-09-031 Electric Utility Wildfire Mitigas		28,120	28,120	
3			4,168	4,168	
4					
5	D. 20-09-032 Evaluate Safety and Reliability .		4,157	4,157	
6			552	552	
7					
8	D. 20-10-023 Electric & Gas Revenue Requiremee		47,612	47,612	
9			5,510	5,510	
10					
11	D. 20-10-024 Natural Gas Leak Reduction		10,153	10,153	
12					
13	D. 20-11-009 Electric & Gas Revenue Requiremee		72,394	72,394	
14			8,378	8,378	
15					
16	D. 20-11-010 Non-Bypassable Charge to Supportd		3,343	3,343	
17					
18	D. 20-11-011 Integrated Distributed Energy Rek		3,487	3,487	
19					
20	D. 20-11-037 2018 Energy Storage Procurement n		11,494	11,494	
21					
22	D. 20-11-038 2018 Energy Storage Procurement n		8,485	8,485	
23					
24	D. 20-11-039 Electricity Integrated Resource s		1,178	1,178	
25					
26	D. 20-11-040 Electricity Integrated Resource s		2,226	2,226	
27					
28	D. 20-11-041 2020 Utility Operation Cost of Ct		142,136	142,136	
29			21,069	21,069	
30					
31	D. 20-11-042 Natural Gas Rate Revision & Storn		45,886	45,886	
32					
33					
34	California Public Utilities Commission fees	14,050,454		14,050,454	
35		1,969,785		1,969,785	
36					
37	FERC Proceedings		423,835	423,835	
38			155,016	155,016	
39					
40	Miscellaneous*		11,436,318	11,436,318	
41			3,784,021	3,784,021	
42	D. 20-01-016 DISTRIBUTED ENERGY & RULE 21		-3,832	-3,832	
43					
44					
45					
46	TOTAL	16,020,239	18,103,850	34,124,089	

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	39,329					1
							2
Elec	928	6,492					3
							4
Elec	928	18,702					5
							6
Elec	928	3,344					7
							8
Elec	928	3,832					9
							10
Elec	928	13,721					11
							12
Elec	928	21,317					13
							14
Elec	928	6,382					15
							16
Elec	928	4,299					17
							18
Elec	928	22,540					19
							20
Elec	928	19,643					21
							22
Elec	928	2,471					23
							24
Elec	928	26,126					25
							26
Elec	928	5,473					27
							28
Elec	928	10,258					29
							30
Elec	928	14,287					31
							32
Elec	928	2,281					33
							34
Elec	928	5,867					35
Gas	928	679					36
							37
Elec	928	14,225					38
							39
Elec	928	22,514					40
							41
Elec	928	1,494					42
Gas	928	173					43
							44
Elec	928	1,993					45
		34,124,089					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	04/16/2021	End of 2020/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.
Gas	928	277					1
							2
Elec	928	4,597					3
Gas	928	532					4
							5
Elec	928	14,590					6
Gas	928	2,163					7
							8
Elec	928	6,610					9
Gas	928	765					10
							11
Elec	928	18,000					12
							13
Elec	928	9,845					14
							15
Elec	928	116,552					16
							17
Elec	928	60,603					18
							19
Elec	928	6,115					20
							21
Elec	928	1,643					22
Gas	928	190					23
							24
Elec	928	79,462					25
							26
Elec	928	74,152					27
							28
Elec	928	10,559					29
							30
Elec	928	19,113					31
Gas	928	2,833					32
							33
Elec	928	18,039					34
							35
Elec	928	21,589					36
							37
Elec	928	51,066					38
							39
Elec	928	4,006					40
							41
Elec	928	4,172					42
							43
Elec	928	8,393					44
							45
		34,124,089					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	04/16/2021	End of 2020/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	2,904					1
							2
Elec	928	10,222					3
							4
Elec	928	3,386					5
							6
Elec	928	6,111					7
							8
Elec	928	2,433					9
							10
Elec	928	8,463					11
							12
Elec	928	23,233					13
							14
Elec	928	23,727					15
							16
Elec	928	3,246					17
							18
Elec	928	1,269					19
Gas	928	188					20
							21
Elec	928	5,631					22
Gas	928	652					23
							24
Elec	928	1,926					25
							26
Elec	928	28,691					27
							28
Elec	928	4,363					29
							30
Elec	928	106,230					31
Gas	928	12,294					32
							33
Elec	928	134,742					34
Gas	928	15,593					35
							36
Elec	928	4,671					37
							38
Elec	928	560,540					39
Gas	928	64,870					40
							41
Elec	928	8,276					42
Gas	928	958					43
							44
Elec	928	50,217					45
		34,124,089					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	04/16/2021	End of 2020/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.
							1
Elec	928	28,120					2
Gas	928	4,168					3
							4
Elec	928	4,157					5
Gas	928	552					6
							7
Elec	928	47,612					8
Gas	928	5,510					9
							10
Elec	928	10,153					11
							12
Elec	928	72,394					13
Gas	928	8,378					14
							15
Elec	928	3,343					16
							17
Elec	928	3,487					18
							19
Elec	928	11,494					20
							21
Elec	928	8,485					22
							23
Elec	928	1,178					24
							25
Elec	928	2,226					26
							27
Elec	928	142,136					28
Gas	928	21,069					29
							30
Elec	928	45,886					31
							32
							33
Elec	928	14,050,454					34
Gas	928	1,969,785					35
							36
Elec	928	423,835					37
Gas	928	155,016					38
							39
Elec	928	11,471,683					40
Gas	928	3,748,656					41
Elec	928	-3,832					42
							43
							44
							45
		34,124,089					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	04/16/2021	End of 2020/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	NONE
20	Research Council or the Electrical Power	NONE
21	Research Institute	NONE
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)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
1,306,937		588	1,306,937		9
29,744		408	29,744		10
					11
					12
					13
					14
1,336,681			1,336,681		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
	11,803,851	588	11,803,851		27
					28
	11,803,851		11,803,851		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	04/16/2021	End of 2020/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	9,839,935		
4	Transmission	15,259,002		
5	Regional Market			
6	Distribution	52,746,535		
7	Customer Accounts	18,435,537		
8	Customer Service and Informational	17,172,183		
9	Sales			
10	Administrative and General	46,674,881		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	160,128,073		
12	Maintenance			
13	Production	1,852,225		
14	Transmission	12,801,112		
15	Regional Market			
16	Distribution	21,090,527		
17	Administrative and General	1,580,196		
18	TOTAL Maintenance (Total of lines 13 thru 17)	37,324,060		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,692,160		
21	Transmission (Enter Total of lines 4 and 14)	28,060,114		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	73,837,062		
24	Customer Accounts (Transcribe from line 7)	18,435,537		
25	Customer Service and Informational (Transcribe from line 8)	17,172,183		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	48,255,077		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	197,452,133	49,588,497	247,040,630
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	103,894		
35	Transmission	2,816,959		
36	Distribution	27,707,954		
37	Customer Accounts	9,300,238		
38	Customer Service and Informational	2,283,036		
39	Sales			
40	Administrative and General	16,223,378		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	58,435,459		
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	843,286		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	7,545,524		
49	Administrative and General	504,900		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	8,893,710		
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	103,894		
56	Transmission (Lines 35 and 47)	3,660,245		
57	Distribution (Lines 36 and 48)	35,253,478		
58	Customer Accounts (Line 37)	9,300,238		
59	Customer Service and Informational (Line 38)	2,283,036		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	16,728,278		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	67,329,169	15,747,628	83,076,797
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	264,781,302	65,336,125	330,117,427
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	76,961,317	131,721,151	208,682,468
69	Gas Plant	19,543,751	28,366,291	47,910,042
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	96,505,068	160,087,442	256,592,510
72	Plant Removal (By Utility Departments)			
73	Electric Plant	7,429,288	12,316,241	19,745,529
74	Gas Plant	1,077,061	1,355,607	2,432,668
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,506,349	13,671,848	22,178,197
77	Other Accounts (Specify, provide details in footnote):			
78	3rd Party Billings, Gas	173,455	1,857,149	2,030,604
79	3rd Party Billings, Electric	751,146	5,387,804	6,138,950
80	Affiliate Billlings, Gas		7,298,951	7,298,951
81	Affiliate Billings, Electric		19,956,281	19,956,281
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	924,601	34,500,185	35,424,786
96	TOTAL SALARIES AND WAGES	370,717,320	273,595,600	644,312,920

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

FERC accounts 417 and 426 are not included in the detail classification lines or summary totals. The 2020 amounts for these accounts are:

417 $4,091,540

426 $812,523

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 Service	Ajds.	Transfers	Balance End of Year
303 Misc. Intangible Plant	617,879,685	77,271,175	9,115,788	(983,500)		685,051,572
389 Land & Land Rights	7,522,569					7,522,569
390 Structures & Improvs	441,728,079	66,766,055				508,494,134
391 Office Furn & Equip	110,327,357	39,561,327	3,110,504	(19,579)		146,758,601
392 Transportation Equip	12,515,395	477				12,515,872
393 Stores Equipment	333,836					333,836
394 Tools, Shop Equipment	3,517,766		16,503			3,501,263
395 Laboratory Equipment	1,731,117					1,731,117
396 Power Operated Equip						
397 Communication Equip	255,464,663	51,910,429	1,300,688			306,074,404
398 Miscellaneous Equip	5,136,414				(1,549,099)	3,587,315
FIN 47 ARC - Common	2,652,762	4,514,540				7,167,302
Fleet Capital Lease	63,603,132	28,630,997	922,641			91,311,488
Other Common Cap Lease	117,108,736	1,733,518	827,628			118,014,626
TOTAL COMMON PLANT	1,639,521,511	270,388,518	15,293,752	(1,003,079)	(1,549,099)	1,892,064,099
Construction Work in Prog	257,806,782	160,456,191				418,262,973
TOTAL COMMON PLANT	1,897,328,293	430,844,709	15,293,752	(1,003,079)	(1,549,099)	2,310,327,072

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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, 2020 Accumulated Depreciation
303 Misc. Intangible Plant	483,279,096
389 Land & Land Rights	27,776
390 Structures & Improvements	176,350,488
391 Office Furniture & Equipment	57,351,952
392 Transportation Equipment	3,764,833
393 Stores Equipment	56,013
394 Tools, Shop, & Garage Equipment	1,268,321
395 Laboratory Equipment	941,246
396 Power Operated Equipment	(192,979)
397 Communication Equipment	114,252,134
398 Miscellaneous Equipment	595,629
108.4 Retirement Work in Progress	
FIN 47 Accumulated Depreciation	1,754,274
Fleet Capital Lease	34,134,806
Other Capital Lease	34,271,641
Total Accumulated Depreciation	907,855,230

Split of Common Utility Plant to Departments: (excluding CWIP)

		December 31, 2020 Balance End of Year	Accumulated Depreciation
Electric	73.22%	1,385,369,333	664,731,600
Gas	26.78%	506,694,766	243,123,630
	100.00%	1,892,064,099	907,855,230

COMMON UTILITY PLANT AND EXPENSES

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

ACCOUNT	Ad Valorem Taxes Note (1)	Depreciation Note (2)
303 Misc. Intangible Plant		74,397,800
389 Land & Land Rights		0
390 Structures & Improvements		16,058,062
391 Office Furniture & Equipment		21,663,973
392 Transportation Equipment		1,172,383
393 Stores Equipment		17,159
394 Portable Tools		185,823
395 Laboratory Equipment		76,515
396 Power Operated Equipment		0
397 Communication Equipment		20,652,395
398 Miscellaneous Equipment		321,832
TOTAL		134,545,941

(1) Ad Valorem Taxes on property are assessed by the State Board of Equalization and consists of one-half of the taxes from each fiscal tax year 2019-2020 and 2020-2021. 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 2020.

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	04/16/2021	End of 2020/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	113,530,749	192,693,643	493,780,164	696,151,611
2	Net Purchases (Account 555)	(35,077,759)	(91,307,676)	(293,685,180)	(378,949,450)
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services	(790,180)	(1,139,055)	(5,867,751)	(9,859,526)
6	Other Items (list separately)				
7	Congestion	682,338	2,132,668	6,675,653	8,541,831
8	CRR (Congestion Revenue Rights)	(7,854,663)	(12,578,086)	(22,614,710)	(37,930,530)
9	GMC (Grid Management Charges)	2,117,195	4,240,806	7,306,452	9,846,858
10	Other	(1,609,769)	(3,783)	7,663,014	5,407,981
11	UFE (Unaccounted for Energy)	1,663,454	2,542,290	(1,061,142)	(2,691,133)
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	72,661,365	96,580,807	192,196,500	290,517,642

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year – Usage - Related Billing Determinant – Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year – Usage - Related Billing Determinant – Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	1,449,221	MWH	14,276,718	2,904,934	MWH	24,136,245
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)	1,449,221		14,276,718	2,904,934		24,136,245

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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	2,839	9	17	2,839					
2	February	2,836	4	18	2,836					
3	March	2,641	2	18	2,641					
4	Total for Quarter 1				8,316					
5	April	2,728	24	18	2,728					
6	May	3,000	6	17	3,000					
7	June	3,275	10	17	3,275					
8	Total for Quarter 2				9,003					
9	July	3,491	12	17	3,491					
10	August	4,028	18	17	4,028					
11	September	4,608	5	16	4,608					
12	Total for Quarter 3				12,127					
13	October	4,308	1	15	4,308					
14	November	2,935	5	17	2,935					
15	December	2,952	17	17	2,952					
16	Total for Quarter 4				10,195					
17	Total Year to Date/Year				39,641					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,398,115
3	Steam	3,044,741			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage	40,303	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	10,344,942
7	Other	87,180			
8	Less Energy for Pumping	58,299	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	3,113,925	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	43,417
10	Purchases	22,546,881	27	Total Energy Losses	874,332
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	25,660,806
12	Received	1,323,869			
13	Delivered	1,323,869			
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)	25,660,806			

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,239,065	563,064	2,839	9	17
30	February	1,167,131	629,790	2,836	4	18
31	March	1,053,510	896,005	2,641	2	18
32	April	989,478	845,651	2,728	24	18
33	May	1,053,944	738,750	3,000	6	17
34	June	1,080,477	797,352	3,275	10	17
35	July	1,181,837	1,230,057	3,491	12	17
36	August	1,360,903	699,910	4,028	18	17
37	September	1,520,459	1,655,813	4,608	5	16
38	October	1,393,824	961,274	4,308	1	15
39	November	1,200,302	604,469	2,935	5	17
40	December	1,157,185	722,807	2,952	17	17
41	TOTAL	14,398,115	10,344,942			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	5881			1639		
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	2019493000			79251000		
13	Cost of Plant: Land and Land Rights	14480000			0		
14	Structures and Improvements	78719363			5075863		
15	Equipment Costs	524741837			102799113		
16	Asset Retirement Costs	0			0		
17	Total Cost	617941200			107874976		
18	Cost per KW of Installed Capacity (line 17/5) Including	1091.7689			1123.6977		
19	Production Expenses: Oper, Supv, & Engr	1447069			43657		
20	Fuel	56474194			3046408		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	3958359			55097		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3251104			596076		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	238179			0		
31	Maintenance of Boiler (or reactor) Plant	937592			0		
32	Maintenance of Electric Plant	3893777			1776434		
33	Maintenance of Misc Steam (or Nuclear) Plant	3779435			11650		
34	Total Production Expenses	73979709			5529322		
35	Expenses per Net KWh	0.0366			0.0698		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS	0	0	GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	0	0	MCF		
38	Quantity (Units) of Fuel Burned	14265789	0	0	775439	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.959	0.000	0.000	3.929	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.873	0.000	0.000	3.844	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.038	0.000	0.000
44	Average BTU per KWh Net Generation	7255.000	0.000	0.000	10049.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Desert Star* (d)			Plant Name: *Cuyamaca* (e)			Plant Name: (f)			Line No.
Combined Cycle			Gas Turbine						1
Semi-Outdoor			Semi-Outdoor						2
2000			2002						3
2000			2002						4
536.00			47.00			0.00			5
485			47			0			6
8784			179			0			7
450			47			0			8
450			47			0			9
450			47			0			10
23			1			0			11
1025248240			6811000			0			12
0			0			0			13
32628792			1891561			0			14
303947685			30161002			0			15
5259070			0			0			16
341835547			32052563			0			17
637.7529			681.9694			0			18
835295			14105			0			19
28872341			492623			0			20
0			0			0			21
2032822			23681			0			22
0			0			0			23
0			0			0			24
1310415			276268			0			25
0			0			0			26
0			0			0			27
0			0			0			28
41			0			0			29
0			16453			0			30
2215456			56			0			31
7747466			829507			0			32
1004010			1265			0			33
44017846			1653958			0			34
0.0429			0.2428			0.0000			35
GAS			GAS						36
MCF			MCF						37
7852812	0	0	76293	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.677	0.000	0.000	6.457	0.000	0.000	0.000	0.000	0.000	41
3.598	0.000	0.000	6.318	0.000	0.000	0.000	0.000	0.000	42
0.028	0.000	0.000	0.072	0.000	0.000	0.000	0.000	0.000	43
7938.000	0.000	0.000	11504.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	04/16/2021	End of 2020/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	04/16/2021	End of 2020/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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			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	04/16/2021	End of 2020/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			3,305,506
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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						1
						2
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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	04/16/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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.
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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	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	Octillo Switchyard	Imperial Valley	500.00	500.00	3	21.60		1
7	Octillo Switchyard	Ocotillo Express Sub	500.00	500.00	3	0.06		1
8	San Luis Rey	Mission	230.00	230.00	3,1S		30.48	2
9			230.00	230.00	2W	4.26		1
10		Mission	230.00	230.00	4		0.05	2
11	San Onofre		230.00	230.00	2S		0.43	5
12			230.00	230.00	2S,3		16.76	2
13		San Luis Rey	230.00	230.00	1S,2W	0.75		1
14	San Luis Rey		230.00	230.00	1S,3		5.81	2
15		Encina	230.00	230.00	1S,3		1.49	2
16	San Luis Rey	San Luis Rey	230.00	230.00	2W	4.26		1
17			230.00	230.00	1S,3		30.48	2
18		Mission	230.00	230.00	4		0.05	2
19	San Luis Rey		230.00	230.00	1S,2W,3S,3	17.61		1
20			230.00	230.00	1S		0.07	2
21		San Onofre	230.00	230.00	2S		0.45	5
22	San Onofre		230.00	230.00	1S,3		6.30	2
23			230.00	230.00	2S,3		0.50	5
24		Talega	230.00	230.00	3	0.11		1
25	San Onofre		230.00	230.00	2W,2S	0.75		1
26			230.00	230.00	2S		0.43	5
27		San Luis Rey	230.00	230.00	2S,3		16.76	2
28	San Luis Rey		230.00	230.00	1S,3		5.84	2
29			230.00	230.00	1S,3		1.56	2
30			230.00	230.00	3		7.19	2
31			230.00	230.00	1S		5.16	2
32			230.00	230.00	1S		0.82	2
33		Palomar Energy	230.00	230.00	1S	0.26		1
34	Encina		230.00	230.00	1S,3		17.91	2
35		Penasquitos	230.00	230.00	1S		0.12	2
36					TOTAL	1,409.89	668.40	514

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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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	Penasquitos		230.00	230.00	1S		2.20	2
2		Old Town	230.00	230.00	1S	7.19		1
3	Palomar		230.00	230.00	1S		0.18	2
4		Old Town	230.00	230.00	1S		0.22	2
5	Palomar		230.00	230.00	1S		0.18	2
6		Old Town	230.00	230.00	1S		0.22	2
7	East County	Eco Gen 1	230.00	230.00	1S		0.23	2
8	Miguel	Bay Blvd	230.00	230.00	2S		9.65	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 Boulavard		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	1,409.89	668.40	514

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		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		9.53	2
8		Bay Blvd	230.00	230.00	4	0.17		1
9	Imperial Valley	NOSDGE23043_1	230.00	230.00	1S	0.04		1
10	IV Bay 12N	NOSDGE23045-6_1	230.00	230.00	1S	0.06		2
11	IV Bay 13N	NOSDGE23045-6_1	230.00	230.00	1S	0.06		2
12	IV Bay 13S	NOSDGE23047-8_1	230.00	230.00	1S	0.09		2
13	IV Bay 14S	NOSDGE23047-8_1	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		Sycamore	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	SCR	NOSDGE_23056_2	230.00	230.00	1s	0.06		1
30	NOSDGE_23056_2	SVC SUB	230.00	230.00	4	0.96		1
31	Imperial Valley	NOSDGE23061_1	230.00	230.00	1S	0.06		1
32	Imperial Valley		230.00	230.00	1S		2.78	2
33			230.00	230.00	2S		0.11	2
34			230.00	230.00	3		2.34	2
35		Drew Switchyard	230.00	230.00	3S		0.10	1
36					TOTAL	1,409.89	668.40	514

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

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1	Drew Switchyard	NOSDGE23067_1	230.00	230.00	1S	0.04		1
2	Drew Switchyard	NOSDGE23068_1	230.00	230.00	1S	0.04		1
3	Pio Pico Generator	Otay Mesa Sy	230.00	230.00	1S	0.04		1
4	Penasquitos		230.00	230.00	1S		2.83	2
5			230.00	230.00	4	10.54		1
6			230.00	230.00	4	0.93		1
7		Sycamore Canyon	230.00	230.00	4	0.39		1
8	Encina	Encina Gen 1	230.00	230.00	4	0.03		1
9	OM	OM GEN 4	230.00	230.00	1S		0.16	1
10	San Luis Rey		230.00	230.00	1S		0.09	2
11		GIS Terminal	230.00	230.00	4		0.10	2
12	San Luis Rey		230.00	230.00	1S		0.09	2
13		GIS Terminal	230.00	230.00	4		0.09	2
14	Imperial Valley	Phase Shifting Transformer	230.00	230.00	1S		0.17	2
15	Z172244	Z172242	230.00	230.00	1S		0.07	2
16	Z189533	Z189535	230.00	230.00	3	0.27		1
17	East County	Eco Gen 1	230.00	230.00	3		0.23	2
18	Drew Switchyard		230.00	230.00	1S		2.39	2
19		Z46503	230.00	230.00	3		2.71	2
20	Encina Switchyard		138.00	230.00	1S		0.04	2
21		Cannon	138.00	230.00	1S		0.11	2
22	Encina Switchyard		138.00	230.00	1S,3		1.47	2
23			138.00	230.00	2W,1S,2S,3S,3	17.01		1
24	Z105030	Batiquitos	138.00	230.00	4	0.72		1
25			138.00	230.00	4	0.72		1
26		Penasquitos	138.00	230.00	3		3.33	2
27	Palomar		138.00	138.00	1S	0.03		1
28		Batiquitos	138.00	230.00	1S		2.68	2
29	Encina Switchyard		138.00	230.00	1S,3		1.48	2
30		Palomar	138.00	230.00	1S,2S,3		1.61	2
31	Telegraph Canyon	Proctor Valley	138.00	138.00	1W,1S,3		2.60	2
32	Friars		138.00	138.00	4	0.17		1
33			138.00	138.00	1S,3		4.11	2
34			138.00	138.00	1S,3		1.82	2
35			138.00	138.00	1S,3	5.43		1
36					TOTAL	1,409.89	668.40	514

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1		Penasquitos	138.00	138.00	1S,3		1.40	2
2	Doublet Tap		138.00	138.00	1W,1S		0.52	3
3		Doublet	138.00	138.00	1W,1S		0.79	2
4	Shadowridge	Z119772	138.00	138.00	1S		3.74	2
5	Z119772		138.00	138.00	1W,1S,3	0.20		1
6		NC Metering	138.00	138.00	1W	0.39		1
7	Z119772		138.00	230.00	3		1.11	2
8		Chicarita	138.00	138.00	2W,2S	10.91		1
9	Telegraph Canyon		138.00	138.00	1S	0.03		1
10			138.00	138.00	3		5.80	2
11			138.00	138.00	4	4.04		1
12	Z223732		138.00	138.00	3			1
13		Z189532	138.00	138.00	3	3.79		1
14			138.00	138.00	3	0.39		1
15		Grant Hill	138.00	138.00	1W,1S	1.01		1
16	Capistrano		138.00	138.00	1W	0.10		1
17			138.00	138.00	1S,3		1.56	2
18			138.00	138.00	1S,3		4.69	2
19		Pico	138.00	138.00	4		0.32	2
20	Santee		138.00	138.00	1W,1S	2.34		1
21			138.00	138.00	1S		4.61	2
22			138.00	138.00	2S	0.27		1
23		Los Coches	138.00	138.00	2S	0.08		1
24	Sycamore		138.00	138.00	4	0.20		1
25		Chicarita	138.00	138.00	1W,2W,1S,2S	5.78		1
26	Sycamore		138.00	138.00	1S		6.65	2
27		Santee	138.00	138.00	1W,1S	1.55		1
28	Mission		138.00	138.00	1W	0.09		1
29			138.00	138.00	1S,3		3.23	2
30	Z677977	Z874970	138.00	138.00	3	4.97		2
31	Z874970	Carlton Hills	138.00	138.00	1S,3		1.48	2
32	Telegraph Canyon		138.00	138.00	1S	0.04		1
33			138.00	138.00	1S,3		2.55	2
34		Miguel 60 Tap	138.00	138.00	1S,3		0.61	2
35	Miguel 60 Tap	Miguel	138.00	138.00	1S		0.95	2
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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 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	Miguel 60 Tap	Z119793	138.00	138.00	1S	0.02		1
2	Z119793	Z200591	138.00	138.00	1S,2S	0.50		1
3			138.00	138.00	1S,3		13.49	2
4		Los Coches	138.00	138.00	1S,3		1.41	2
5	Batiquitos		138.00	138.00	1S		2.61	2
6		Shadowridge	138.00	138.00	1S		3.73	2
7	Miguel		138.00	138.00	1S	0.72		1
8		Proctor Valley	138.00	138.00	1S,3		0.61	2
9	Friars		138.00	138.00	4	0.09		1
10		Mission	138.00	138.00	1S,3		1.26	2
11	Sycamore		138.00	138.00	1S		3.85	2
12			138.00	138.00	1S		1.78	2
13		Carlton Hills	138.00	138.00	1S,3		1.48	2
14	Trabuco		138.00	138.00	1S	0.68		1
15			138.00	138.00	1S	0.08		1
16			138.00	138.00	4	3.03		1
17		Margarita	138.00	138.00	4	0.23		1
18	Talega	Rancho Mission Viejo	138.00	138.00	1W,1S	6.42		1
19	Trabuco		138.00	138.00	1W,1S	3.66		1
20			138.00	138.00	1W,3		0.16	2
21			138.00	138.00	1S,3		6.34	2
22		Pico	138.00	138.00	4		0.32	2
23	Capistrano		138.00	138.00	1W	3.59		1
24		Trabuco	138.00	138.00	1W		0.15	2
25	San Mateo	Talega	138.00	138.00	1W,1S	1.29		1
26	Talega Tap		138.00	138.00	1W,3		2.96	2
27			138.00	138.00	1W,2W,1S,2S,	8.10		1
28			138.00	138.00	4		1.84	2
29		Laguna Niguel	138.00	138.00	4	0.35		1
30	Pico		138.00	138.00	1S,3		0.70	2
31		Talega	138.00	138.00	1W	0.41		1
32	Capistrano		138.00	138.00	1W	0.01		1
33			138.00	138.00	1W		0.15	2
34			138.00	138.00	1W,1S	1.36		1
35		Laguna Niguel	138.00	138.00	4		1.84	2
36					TOTAL	1,409.89	668.40	514

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION 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	Rancho Mission Viejo	Margarita	138.00	138.00	1W,1S	3.06		1
2	Mission		138.00	138.00	1W,1S	2.56		1
3		Grant Hill	138.00	138.00	4	2.84		1
4	Cannon	Encina Hub	138.00	138.00	1S,3		1.29	2
5	Encina Hub	Shadowridge	138.00	138.00	1S,2S,2W	6.73		1
6	East County		138.00	138.00	1S,2S	6.99		1
7			138.00	138.00	4	5.54		1
8			138.00	138.00	4	1.12		1
9		Boulevard East	138.00	138.00	4	0.18		1
10	Pico		138.00	138.00	3		0.70	2
11		Talega	138.00	138.00	1W,1S	0.47		1
12	Talega		138.00	138.00	3		2.78	2
13		San Mateo	138.00	138.00	1S		0.73	2
14	Encina	Z124528	138.00	230.00	1S		0.04	2
15	Z124528	Cannon	138.00	230.00	1S		0.11	2
16	Boulavard	Boulevard East	238.00	138.00	4		0.99	1
17	East County	Eco Gen 2	138.00	138.00	1S	0.33		1
18	Encina	Encina Gen 1	138.00	138.00	3S	0.03		1
19	13822	De-Energized	138.00	138.00	2W	0.06		1
20	13832	De-Energized	138.00	138.00	3,1S,1W	3.36		1
21	13832	De-Energized	138.00	138.00	3,1S,1W	3.21		1
22	13811	De-Energized	138.00	138.00	1S	1.07		1
23	13811	De-Energized	138.00	138.00	3	5.69		1
24	Cannon	Encina Hub	138.00	138.00	1S,3		1.28	2
25	Encina Hub	Calavera Tap	138.00	138.00	2W	0.39		1
26	Encina Hub	Calavera Tap	138.00	138.00	2W	2.94		1
27	Calavera Tap	San Luis Rey	138.00	138.00	2W	3.89		1
28	Bay Blvd		138.00	138.00	3		2.82	2
29		Telegraph Canyon	138.00	138.00	3		2.98	2
30								
31	69 kV CIRCUITS				1W	670.84	25.40	125
32	69 kV CIRCUITS				2W	7.11	1.38	
33	69 kV CIRCUITS				1S	43.23	1.50	
34	69 kV CIRCUITS				3	20.00	50.61	
35	69 kV CIRCUITS				4	60.97	0.60	
36					TOTAL	1,409.89	668.40	514

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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								
2								
3	COST OF LINE							
4	EXPENSES, EXCEPT ISO							
5	ISO CHARGES							
6								
7								
8								
9								
10								
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22								
23								
24								
25								
26								
27								
28								
29								
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31								
32								
33								
34								
35								
36					TOTAL	1,409.89	668.40	514

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San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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
1-1033.5 ACSR/AW								8
1-1033.5 ACSR/AW								9
1-5000 KCMIL CU E								10
2-1033.5 ACSR/AW								11
2-1033.5 ACSR/AW								12
2-1033.5 ACSR/AW								13
2-1033.5 ACSR/AW								14
2-1109 ACAR								15
1-1033.5 ACSR/AW								16
1-1033.5 ACSR/AW								17
1-5000 KCMIL CU E								18
1-1033.5 ACSR/AW								19
1-1033.5 ACSR/AW								20
2-1033.5 ACSR/AW								21
1-1033.5 ACSR/AW								22
2-1033.5 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
2-1109 ACAR								29
2-1109 ACAR								30
2-1109 ACAR								31
2-900 ACSS/AW								32
2-1109 ACAR								33
2-1109 ACAR								34
2-1033.5 ACSR/AW								35
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	36

TRANSMISSION LINE STATISTICS (Continued)

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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	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
2-1109 ACAR								2
2-900 ACSS/AW								3
2-605 ACSS/AW								4
2-900 ACSS/AW								5
2-605 ACSS/AW								6
2-1113 ACSS/AW								7
2-900 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
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	36

TRANSMISSION LINE STATISTICS (Continued)

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2-900 ACSS/AW								2
2-1033.5 ACSR/AW								3
2-605 ACSS/AW								4
2-1109 ACAR								5
2-900ACSS/AW								6
2-900ACSS/AW								7
2-5000 KCMIL CU								8
2-1033.5 ACSS/AW								9
2-1113 ACSR								10
2-1113 ACSR								11
2-954 AL								12
2-954 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
1-1033.5 ACSR/AW								29
1-3500 KCMIL SEG								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
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	36

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-900 ACSS/AW								1
2-900 ACSS/AW								2
1-1272 ACSS								3
2-900 ACSS/AW								4
2-4000 KCMIL CU								5
2-4000 KCMIL CU E								6
2-5000 KCMIL CU E								7
1-3500 CU								8
1-1033.5 ACSR/AW								9
2-1033.5 ACSR/AW								10
1-5000 KCMIL CU								11
2-1033.5 ACSR/AW								12
1-5000 KCMIL CU								13
2-900 ACSS/AW								14
2-1033.5 ACSR/AW								15
1-1033.5 ACSR/AW								16
2-1113 ACSS/AW								17
2-900 ACSS/AW								18
2-900 ACSS/AW								19
2-1033.5 ACSR/AW								20
2-1109 ACAR								21
2-1109 ACAR								22
2-636 ACSR/AW								23
1-1750 MCM AL								24
2-1750 MCM AL								25
2-1033.5 ACSR/AW								26
2-1033.5 ACSR/AW								27
2-1109 ACAR								28
2-1109 ACAR								29
2-1033.5 ACSR/AW								30
2-636 ACSS/AW								31
2-2500 CU								32
1-636 ACSR/AW								33
1-400 MCM CU								34
1-636 ACSR/AW								35
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	36

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1-636 ACSR/AW								1
1-336 ACSR/AW								2
1-336 ACSR/AW								3
1-1033.5 ACSR/AW								4
1-250 MCM CU								5
1-336 ACSR/AW								6
2-1033.5 ACSR/AW								7
1-636 ACSR/AW								8
2-1033.5 ACSR/AW								9
2-636 ACSR/AW								10
1-2500 KCMIL CU								11
1-1033.5 ACSR/AW								12
2-400 MCM CU								13
2-636 ACSS/AW								14
2-636 ACSR/AW								15
1-1033.5 ACSR/AW								16
1-1033.5 ACSR/AW								17
1-636 ACSR/AW								18
1-1750 MCM CU								19
1-1033.5 ACSR/AW								20
1-605 ACSS/AW								21
2-336 ACSR/AW								22
2-636 ACSR/AW								23
1-3000 KCMIL CU								24
1-636 ACSR/AW								25
1-900 ACSS/AW								26
1-900 ACSS/AW								27
2-336.4 ACSR								28
2-336.4 ACSR								29
4-336.4 MCM								30
1-900 ACSS/AW								31
2-1033.5 ACSR/AW								32
2-636 ACSR/AW								33
2-636 ACSR/AW								34
2-900 ACSS/AW								35
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	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	04/16/2021	End of 2020/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.
2-636 ACSS/AW								1
2-636 ACSR/AW								2
1-636 ACSS/AW								3
1-636 ACSR/AW								4
2-1033.5 ACSR/AW								5
2-1033.5 ACSR/AW								6
2-636 ACSS/AW								7
2-636 ACSR/AW								8
1-1750 KCMIL AL								9
1-900 ACSS/AW								10
1-900 ACSS/AW								11
1-900 ACSS/AW								12
1-900 ACSS/AW								13
1-1033.5 ACSR/AW								14
2-1033.5 ACSR/AW								15
1-1750 KCMIL AL								16
1-1750 KCMIL CU								17
1-1033.5 ACSR/AW								18
1-1033.5 ACSR/AW								19
1-1033.5 ACSR/AW								20
1-1033.5 ACSR/AW								21
1-1750 MCM CU								22
1-1033.5 ACSR/AW								23
1-1033.5 ACSR/AW								24
1-1033.5 ACSR/AW								25
1-336.4 ACSR/AW								26
1-336.4 ACSR/AW								27
1-1750 KCMIL AL								28
1-1750 KCMIL AL								29
1-900 ACSS/AW								30
1-1033.5 ACSR/AW								31
1-636 ACSR/AW								32
1-336.4 ACSR/AW								33
1-336.4 ACSR/AW								34
1-1750 KCMIL AL								35
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	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)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1-1033.5 ACSR/AW								1
2-636 ACSR/AW								2
1-2500 MCM CU								3
2-1109 ACAR								4
1-900 ACSS/AW								5
2-900 ACSS/AW								6
2-2500 KCMIL CU								7
2-3000 KCMIL CU								8
2-5000 KCMIL CU								9
1-1033.5 ACSR/AW								10
1-1033.5 ACSR/AW								11
1-336.4 ACSR/AW								12
1-1033.5 ACSR/AW								13
2-1033.5 ACSR								14
2-1109 ACAR								15
2-2500 KCMIL CU								16
1-636 ACSR/AW								17
1-636 KCMIL ACSR								18
1-1109 ACAR								19
1-336.4 ACSR								20
1-250 MCM CU								21
1-900 ACSS/AW								22
1-250 MCM CU								23
2-1109 ACAR								24
1-1033.5 ACSR/AW								25
1-636 ACSS/AW								26
1-1033.5 ACSR/AW								27
2-636 ACSR/AW								28
2-400 MCM CU								29
								30
								31
								32
								33
								34
								35
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	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	04/16/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
	214,394,078	4,159,562,793	4,373,956,871					3
				14,794,767	29,392,886	2,779,304	46,966,957	4
				3,625,020			3,625,020	5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
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								21
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								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	214,394,078	4,159,562,793	4,373,956,871	18,419,787	29,392,886	2,779,304	50,591,977	36

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

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

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

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

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

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

Schedule Page: 422.7 Line No.: 3 Column: j

Costs available in total only.

Schedule Page: 422.7 Line No.: 3 Column: k

Costs available in total only.

Schedule Page: 422.7 Line No.: 3 Column: l

Costs available in total only.

Schedule Page: 422.7 Line No.: 4 Column: m

Costs available in total only.

Schedule Page: 422.7 Line No.: 4 Column: n

Costs available in total only.

Schedule Page: 422.7 Line No.: 4 Column: o

Costs available in total only.

Schedule Page: 422.7 Line No.: 5 Column: m

Costs available in total only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Loveland	Descanso	15.56	OH	13.11	1	1
2	OTAY	Z183560	1.79	OH	1.68	1	1
3	Z183560	Z169367	0.12	OH	25.00	1	1
4	Z169367	Z183565	0.16	OH	18.75	1	1
5	Z188714	Z31723	5.20	OH	0.58	1	1
6	Z31723	Z188730	0.03	OH	100.00	1	1
7	Z188730	Z188630	0.29	OH	10.34	1	1
8	Z188630	Z100695	0.18	OH	16.67	1	1
9	Z100695	BORDER	0.75	OH	4.00	1	1
10	Z170098	PN RACK	5.40	OH	16.30	1	1
11	DE RACK		11.24	OH	34.61	1	1
12	Z293646		0.02	OH	19,450.00	1	2
13	Z293646	Z100035	13.89	OH	28.01	1	2
14	Z33075	MESA RIM	0.29	UG	10.34	1	1
15	MESA RIM	Z33220	0.24	UG	20.83	2	2
16	Z293940	AVACADO	0.12	UG	8.52	1	1
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
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40							
41							
42							
43							
44	TOTAL		55.28		19,758.74	17	19

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1-636	ACSS/AW	6'	69	1	1	1		3	1
1-4/0	CU B.S	6'	69						2
1-1033.5	ACSR/AW	6'	69						3
1-1033.5	ACSR/AW	6'	69						4
1-636	ACSR/AW	6'	69						5
1-636	ACSR/AW	6'	69						6
1-336.4	ACSR/AW	6'	69						7
1-336.4	ACSR/AW	6'	69						8
1-336.4	ACSR/AW	6'	69	1,135,116	19,074,718	5,395,776	1,473,482	27,079,092	9
1-636	ACSR/AW	9'	69	1,940,081	5,654,895	5,648,685	2,731,292	15,974,953	10
1-636 24/7	ACSR/AW	9'	69						11
1-636 24/7	ACSR/AW	9'	69						12
1-636 24/7	ACSR/AW	9'	69	15,580,907	22,840,518	8,788,160	416,522	47,626,107	13
1-3000	KCMIL U	12'	69			4,399,400	223,235	4,622,635	14
1-3000	KCMIL U	6'	69			4,650,384	194,017	4,844,401	15
1-1750	KCMIL U	11'	69			1,515,185	108,003	1,623,188	16
									17
									18
									19
									20
									21
									22
									23
									24
									25
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									40
									41
									42
									43
				18,656,105	47,570,132	30,397,591	5,146,551	101,770,379	44

Schedule Page: 424 Line No.: 9 Column: c

To report re-build of 8.52 miles for TL649 from Otay Substation to Border Substation for 2020.

Schedule Page: 424 Line No.: 10 Column: c

To report re-build of 5.40 miles for TL6912 from Structure Z170098 to Pendleton Substation for 2020.

Schedule Page: 424 Line No.: 13 Column: c

To report re-build of 25.15 miles for TL629 from TL629 Tap to Descanso Substation for 2020.

Schedule Page: 424 Line No.: 14 Column: c

To report re-build of 0.29 miles for TL6906 from Stucture Z33075 to Mesa Rim Substation for 2020.

Schedule Page: 424 Line No.: 15 Column: c

To report re-build of 0.24 miles for TL677/6978 from Mesa Rim Substation to Z33220 for 2020.

Schedule Page: 424 Line No.: 16 Column: c

To report re-build of 0.12 miles for TL691 from Structure Z293940 to Avacado Substation for 2020.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	BOULEVARD EAST, Boulevard	Dist. Unattended	138.00	12.00	
15	CABRILLO, San Diego	Dist. Unattended	69.00	12.00	
16	CALAVO GARDENS, El Cajon	Dist. Unattended	12.00	4.00	
17	CAMERON, Campo	Dist. Unattended	69.00	12.00	
18	CANNON, Carlsbad	Dist. Unattended	138.00	12.00	
19	CAPISTRANO, San Juan Capistrano	Dist. Unattended	138.00	12.00	
20	CARLTON HILLS, Santee	Dist. Unattended	138.00	12.00	
21	CENTRAL, San Diego	Dist. Unattended	12.00	4.00	
22	CHICARITA, San Diego	Dist. Unattended	138.00	12.00	
23	CHOLLAS , Lemon Grove	Dist. Unattended	69.00	12.00	
24	CHULA VISTA-, San Diego	Dist. Unattended	12.00	4.00	
25	CLAIREMONT, San Diego	Dist. Unattended	69.00	12.00	
26	CORONADO, Coronado	Dist. Unattended	69.00	12.00	
27	CREELMAN, Ramona	Dist. Unattended	69.00	12.00	
28	CRESTWOODCampo	Dist. Unattended	69.00	12.00	
29	CRISTIANITOS Mission Viejo	Dist. Unattended	69.00	12.00	
30	DEL MAR, Del Mar	Dist. Unattended	69.00	12.00	
31	DESCANSO, Descanso	Dist. Unattended	69.00	12.00	
32	DIVISION, San Diego	Dist. Unattended	69.00	12.00	
33	DUNHILL-San Diego	Dist. Unattended	69.00	4.00	
34	EAST OCEANSIDE, Oceanside	Dist. Unattended	12.00	4.00	
35	EASTGATE, San Diego	Dist. Unattended	69.00	12.00	
36	EL CAJON, El Cajon	Dist. Unattended	69.00	12.00	
37	ELLIOTT, San Diego	Dist. Unattended	69.00	12.00	
38	ENCINITAS, Encinitas	Dist. Unattended	69.00	12.00	
39	ENCINITAS, Encinitas	Dist. Unattended	12.00	4.00	
40	ESCO, Escondido	Dist. Unattended	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ESCO, Escondido	Dist. Unattended	12.00	4.00	
2	ESCONDIDO, Escondido	Dist. Unattended	69.00	12.00	
3	F , San Diego	Dist. Unattended	69.00	12.00	
4	FELICITA,Escondido	Dist. Unattended	69.00	12.00	
5	FENTON, San Diego	Dist. Unattended	69.00	12.00	
6	FRIARS, San Diego	Dist. Unattended	138.00	12.00	
7	GARFIELD, El Cajon	Dist. Unattended	69.00	12.00	
8	GENESEE,San diego	Dist. Unattended	69.00	12.00	
9	GLENCLIFF-GC	Dist. Unattended	69.00	12.00	
10	GRANITE, El Cajon	Dist. Unattended	69.00	12.00	
11	GRANT HILLSan Diego	Dist. Unattended	138.00	12.00	
12	HILLTOP, San Diego	Dist. Unattended	12.00	4.00	
13	IMPERIAL BEACH, Imperial Beach	Dist. Unattended	69.00	12.00	
14	IMPERIAL BEACH, Imperial Beach	Dist. Unattended	12.00	4.00	
15	JAMACHA, Jamacha	Dist. Unattended	69.00	12.00	
16	JAPANESE MESA, San Clemente	Dist. Unattended	69.00	12.00	
17	KEARNY, San Diego	Dist. Unattended	69.00	12.00	
18	KEARNY WEST, San Diego	Dist. Unattended	69.00	12.00	
19	KETTNER,San Diego	Dist. Unattended	69.00	12.00	
20	KYOCERA, San Diego	Dist. Unattended	69.00	12.00	
21	LA JOLLA, La Jolla	Dist. Unattended	69.00	12.00	
22	LAGUNA NIGUEL, Laguna Niguel	Dist. Unattended	138.00	12.00	
23	LAS PULGAS-Oceanside	Dist. Unattended	69.00	12.00	
24	LILAC, Valley Center	Dist. Unattended	69.00	12.00	
25	LINCOLN ACRES, National City	Dist. Unattended	12.00	4.00	
26	LOS COCHES, Lakeside	Dist. Unattended	69.00	12.00	
27	LOVELAND, Alpine	Dist. Unattended	69.00	12.00	
28	MARGARITA, Mission Viejo	Dist. Unattended	138.00	12.00	
29	MELROSE, Vista	Dist. Unattended	69.00	12.00	
30	MESA HEIGHTS,SanDiego	Dist. Unattended	69.00	12.00	
31	MESA RIM, San Diego	Dist. Unattended	69.00	12.00	
32	MIRAMAR, San Diego	Dist. Unattended	69.00	12.00	
33	MIRA SORRENTO,San Diego	Dist. Unattended	69.00	12.00	
34	MISSION, San Diego	Dist. Unattended	69.00	12.00	
35	MONSERATE, Fallbrook	Dist. Unattended	69.00	12.00	
36	MONTGOMERY, Chula Vista	Dist. Unattended	69.00	12.00	
37	MORRO HILL, Oceanside	Dist. Unattended	69.00	12.00	
38	MURRAY, La Mesa	Dist. Unattended	69.00	12.00	
39	NATIONAL CITY, National City	Dist. Unattended	69.00	4.00	12.00
40	NAVAL STATION Switchyard, San Diego-NSM	Dist. Unattended	69.00		

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/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	NORTH CITY WEST, San Diego	Dist. Unattended	69.00	12.00	
2	NORTH VISTA-,Vista	Dist. Unattended	12.00	4.00	
3	OCEAN RANCH, Oceanside	Dist. Unattended	69.00	12.00	
4	OCEANSIDE, Oceanside	Dist. Unattended	69.00	12.00	
5	OLD TOWN, San Diego	Dist. Unattended	69.00	12.00	
6	OLIVENHAIN-, Escondido	Dist. Unattended	69.00	12.00	
7	OTAY LAKES, Chula Vista	Dist. Unattended	69.00	12.00	
8	OTAY. Chula Vista	Dist. Unattended	69.00	12.00	
9	PACIFIC BEACH, San Diego	Dist. Unattended	69.00	12.00	
10	PALA, San Diego County	Dist. Unattended	69.00	12.00	
11	PALOMAR AIRPORT, Carlsbad	Dist. Unattended	138.00	12.00	
12	PARADISE, San Diego	Dist. Unattended	69.00	12.00	
13	PENDLETON, Oceanside	Dist. Unattended	69.00	12.00	
14	PICO, San Clemente	Dist. Unattended	138.00	12.00	
15	POINT LOMA SEWAGE, San Diego	Dist. Unattended	12.00	4.00	
16	POINT LOMA, San Diego	Dist. Unattended	69.00	12.00	
17	POMERADO, San Diego	Dist. Unattended	69.00	12.00	
18	POWAY, Poway	Dist. Unattended	69.00	12.00	
19	PROCTOR VALLEY, Bonita	Dist. Unattended	138.00	12.00	
20	RAMONA, Ramona	Dist. Unattended	12.00	4.00	
21	RANCHO CARMEL, San Diego	Dist. Unattended	69.00	12.00	
22	RANCHO MISSION VIEJO, Rancho Mission Viejo	Dist. Unattended	138.00	12.00	
23	RANCHO SANTA FE, RanchoSantaFe	Dist. Unattended	69.00	12.00	
24	RANCHO SANTA FE, RanchoSantaFe	Dist. Unattended	69.00	4.00	
25	RINCON, Rincon	Dist. Unattended	69.00	12.00	
26	ROLANDO, San Diego	Dist. Unattended	12.00	4.00	
27	ROSE CANYON, San Diego	Dist. Unattended	69.00	12.00	
28	SALT CREEK, Chula Vista	Dist. Unattended	69.00	12.00	
29	SAMPSON, San Diego	Dist. Unattended	69.00	12.00	
30	SAN CLEMENTE, San clemente	Dist. Unattended	12.00	4.00	
31	SAN LUIS REY-Oceanside	Dist. Unattended	69.00	12.00	
32	SAN MARCOS, San Marcos	Dist. Unattended	69.00	12.00	
33	SAN MATEO, San Clemente	Dist. Unattended	138.00	12.00	
34	SAN YSIDRO, San Ysidro	Dist. Unattended	69.00	12.00	
35	SANTA YSABEL, Santa Ysabel	Dist. Unattended	69.00	12.00	
36	SANTEE, Santee	Dist. Unattended	138.00	12.00	
37	SCRIPPS, San Diego	Dist. Unattended	69.00	12.00	
38	SEWAGE PUMP STA (3)., San Diego	Dist. Unattended	12.00	4.00	
39	SHADOWRIDGE, Vista	Dist. Unattended	138.00	12.00	
40	SHORECLIFFS-San Clemente	Dist. Unattended	12.00	4.00	

Name of Respondent San Diego Gas & Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PENASQUITOS, San Diego	Trans. Unattended	230.00	138.00	
2	PENASQUITOS, San Diego	Trans. Unattended	230.00	69.00	
3	SAN LUIS REY, Oceanside,	Trans. Unattended	230.00	69.00	
4	SILVERGATE, San Diego	Trans. Unattended	230.00	69.00	
5	SONGS	Trans. Unattended	230.00	230.00	
6	SUNCREST, Japatul	Trans. Unattended	500.00	230.00	12.00
7	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	69.00	
8	SYCAMORE CANYON, San Diego	Trans. Unattended	230.00	138.00	
9	TALEGA, San Clemente	Trans. Unattended	138.00	69.00	
10	TALEGA, San Clemente	Trans. Unattended	230.00	138.00	
11	WABASH switchyard, San Diego	Trans. Unattended	69.00		
12					
13					
14					
15					
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37					
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39					
40					

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

Capacity of Substation (In Service) (In MVa) (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
28	1					14
56	2					15
7	2					16
6	1					17
112	4					18
56	2					19
56	2					20
6	1					21
84	3					22
56	2	1				23
6	2					24
56	2					25
56	2					26
84	3					27
13	1					28
8	1					29
84	3					30
7	1					31
53	2					32
8	1					33
6	1					34
56	2					35
112	4					36
84	3					37
56	2					38
6	1					39
56	2					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	04/16/2021	End of 2020/Q4

SUBSTATIONS (Continued)

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4	1					1
112	4					2
84	3					3
84	3					4
8	1					5
56	2					6
28	1					7
112	4					8
7	1					9
112	4					10
56	2					11
3	1					12
56	2					13
6	1					14
84	3					15
14	2					16
84	3					17
112	4	1				18
56	2					19
9	1					20
56	2					21
112	4					22
28	1					23
56	2					24
6	1					25
84	3					26
28	1					27
112	4					28
112	4					29
84	3					30
112	4					31
84	3					32
56	2					33
112	4					34
56	2					35
56	2					36
13	1					37
112	4	1				38
14	2					39
						40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
56	2					1
3	1					2
56	2					3
56	2					4
84	3	2				5
28	1					6
5	1					7
56	2	1				8
56	2					9
28	1					10
84	3					11
56	2					12
56	2					13
56	2					14
13	1					15
84	3					16
84	3					17
56	2					18
56	2	1				19
6	1					20
84	3					21
56	2					22
41	2					23
6	1					24
25	2					25
13	2					26
56	2					27
56	2					28
112	4					29
3	1					30
112	4					31
112	4					32
45	2					33
56	2					34
12	1					35
56	2					36
84	3					37
46	6					38
84	3					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3	1					1
56	2					2
56	2					3
8	1					4
28	1					5
56	2	1				6
112	4					7
112	4					8
112	4					9
						10
84	3					11
28	1					12
56	3					13
10	2					14
28	1					15
8	1					16
7	1					17
6	1					18
448	2					19
						20
1120	1					21
392	1					22
						23
784	2					24
672	3					25
						26
2840	9	2				27
448	2					28
448	2					29
784	2					30
2240	6	1	500/17	2	500	31
50	1					32
200	1					33
224	1					34
784	2					35
10	3					36
						37
448	2					38
						39
520	3					40

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SUBSTATIONS (Continued)

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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)	
392	1	1				1
448	2					2
672	3		230/17	2	500	3
448	2	1				4
250			230/17	1	250	5
2240	6	1				6
672	3	1				7
392	1	1				8
140	1	1				9
1102	4		230/17	2	500	10
						11
						12
						13
						14
						15
						16
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Construction Work in Progress	Sempra Energy	107	11,868,023
3	Other Utility Plant	Sempra Energy	118	159,139
4	Accounts Receivable from Associated Companies	Sempra Energy	146	2,198
5	Stores Expense Undistributed	Sempra Energy	163	6,686
6	Prepayments	Sempra Energy	165	232,957,089
7	Unamortized Debt Expense	Sempra Energy	181	1,953,759
8	Other regulatory assets	Sempra Energy	182	648,873
9	Clearing Accounts	Sempra Energy	184	3,322,257
10	Deferred Debits	Sempra Energy	186	1,282,458
11	Accumulated Other Comprehensive Income	Sempra Energy	219	-3,617,282
12	Accumulated Provision for Pensions and Benefits	Sempra Energy	228.3	4,671,134
13	Accumulated miscellaneous operating provisions	Sempra Energy	228.4	27,744
14	Accounts Payable	Sempra Energy	232	251,409
15	Other regulatory liabilities	Sempra Energy	254	-648,873
16	Expenses of Nonutility Operations	Sempra Energy	417.1	2,673,810
17	Exp for Certain Civic, Political and Related Activ	Sempra Energy	426.4	2,036,468
18	Other interest expense	Sempra Energy	431	123,428
19	Other Electric Revenues	Sempra Energy	456	2,118
20	**Non-power Goods or Services Provided for Affiliate**			
21	Accounting & Finance	Sempra Energy	146	1,330,922
22	Depreciation Expense	Sempra Energy	146	528,523
23	Engineering / Const. Services	Sempra Energy	146	4,511
24	Environmental Services	Sempra Energy	146	13,606
25	External Affairs	Sempra Energy	146	263,897
26	Fleet Services	Sempra Energy	146	8,083
27	Human Resources	Sempra Energy	146	9,956,275
28	Information Technology	Sempra Energy	146	3,075,043
29	Real Estate & Facilities	Sempra Energy	146	3,849,141
30	Supply Management	Sempra Energy	146	1,466,490
31	Depreciation Expense	Sempra LNG	146	16,029
32	Environmental Services	Sempra LNG	146	91
33	Human Resources	Sempra LNG	146	347,642
34	Real Estate & Facilities	Sempra LNG	146	50,946
35	Supply Management	Sempra LNG	146	76,849
36	Engineering / Const. Services	Energia Sierra Juarez	146	309,616
37	Accounting & Finance	Southern California Gas Company	146	30,362,651
38	Customer Services	Southern California Gas Company	146	477,071
39	DepreciationExpense	Southern California Gas Company	146	4,666,124
40	Engineering and Construction Services	Southern California Gas Company	146	156,865
41	Environmental Services	Southern California Gas Company	146	51,100
42	External Affairs	Southern California Gas Company	146	2,443,156
1	**Non-power Goods or Services Provided by Affiliated**			
2	Operation supervision and engineering	Sempra Energy	500	878

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Miscellaneous Steam Power Expenses	Sempra Energy	506	745
4	Maintenance of miscellaneous steam plant	Sempra Energy	514	955
5	Operation Supervision and Engineering	Sempra Energy	546	340
6	Miscellaneous other power generation expenses	Sempra Energy	549	1,021
7	Maintenance of misc other power generation plant	Sempra Energy	554	3,328
8	System control and load dispatching	Sempra Energy	556	148
9	Other expenses	Sempra Energy	557	1,267
10	Transmission Operation Supv & Engineering	Sempra Energy	560	226,178
11	Load Dispatch	Sempra Energy	561	1,958
12	Station expenses	Sempra Energy	562	4,054
13	Miscellaneous Transmission Expenses	Sempra Energy	566	211,770
14	Maintenance of Structures	Sempra Energy	569	7,145
15	Maintenance of station equipment	Sempra Energy	570	3,525
16	Maintenance of overhead lines	Sempra Energy	571	2,632
17	Distribution Operation Supv & Engineering	Sempra Energy	580	47,911
18	Load dispatching	Sempra Energy	581	4,731
19	Underground line expenses	Sempra Energy	584	161
20	**Non-power Goods or Services Provided for Affiliate**			
21	Fleet Services	Southern California Gas Company	146	-3,785
22	Human Resources	Southern California Gas Company	146	-1,948,797
23	Information Technology	Southern California Gas Company	146	70,040,675
24	Real Estate & Facilities	Southern California Gas Company	146	1,794,656
25	Supply Management	Southern California Gas Company	146	52,000
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Meter Expenses	Sempra Energy	586	11,724
3	Miscellaneous Distribution Expenses	Sempra Energy	588	300,513
4	Maintenance supervision and engineering	Sempra Energy	590	664

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
San Diego Gas & Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2021	End of 2020/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	Maintenance of station equipment	Sempra Energy	592	853
6	Maintenance of Overhead Lines	Sempra Energy	593	7,944
7	Maintenance of meters	Sempra Energy	597	371
8	Operation supervision and engineering	Sempra Energy	850	2,155
9	Compressor station labor and expenses	Sempra Energy	853	318
10	Measuring and regulating station expenses	Sempra Energy	857	67
11	Maintenance of mains	Sempra Energy	863	29,292
12	Maintenance of measuring &regulating station equip	Sempra Energy	865	850
13	Operation Supervision and Engineering	Sempra Energy	870	50,456
14	Mains and services expenses	Sempra Energy	874	14,627
15	Measuring and regulating station expenses—General	Sempra Energy	875	111
16	Customer installations expenses	Sempra Energy	879	27,265
17	Distribution Other Expenses	Sempra Energy	880	19,069
18	Maintenance of mains	Sempra Energy	887	3,270
19	Maintenance of Meters and House Regulators	Sempra Energy	893	773
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 other equipment	Sempra Energy	894	171
3	Meter Reading Expenses	Sempra Energy	902	6,775
4	Customer Records and Collection Expenses	Sempra Energy	903	19,252
5	Customer Assistance Expenses	Sempra Energy	908	17,688
6	Miscellaneous Customer Service and Info Expenses	Sempra Energy	910	561,158

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7	Office Supplies and Expenses	Sempra Energy	921	851,529
8	Outside Services Employed	Sempra Energy	923	58,904,922
9	Property Insurance	Sempra Energy	924	334,690
10	Injuries and Damages	Sempra Energy	925	114,194
11	Employee Pension and Benefits	Sempra Energy	926	51,415,505
12	Regulatory Commission Expenses	Sempra Energy	928	223,024
13	Miscellaneous General Expense	Sempra Energy	930.2	1,342,098
14	Maintenance of General Plant	Sempra Energy	935	8,615
15	Purchased Power	Energia Sierra Juarez	555	44,126,342
16	Construction Work in Progress	Southern California Gas Company	107	10,219,598
17	Other Utility Plant	Southern California Gas Company	118	3,507,725
18	3rd Party Bill A/R-Clearing	Southern California Gas Company	143.8	168,449
19	Stores Expense Undistributed	Southern California Gas Company	163	5,520
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Clearing Accounts	Southern California Gas Company	184	1,147,924
3	Miscellaneous Deferred Debits	Southern California Gas Company	186	430,732
4	RD&D Expenditures	Southern California Gas Company	188	551,552
5	Accounts Payable	Southern California Gas Company	232	153,365
6	Expense of NonUtility Operations	Southern California Gas Company	417.1	-13,231
7	Exp for Certain Civic, Political and Related Activ	Southern California Gas Company	426.4	114,668
8	Other Gas Revenues	Southern California Gas Company	495	-365,728

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
9	ET Operations Executive Comp	Southern California Gas Company	560	-1,106
10	Miscellaneous Transmission Expenses	Southern California Gas Company	566	323
11	Miscellaneous Distribution Expenses	Southern California Gas Company	588	22,979
12	Natural Gas TR Line Prch	Southern California Gas Company	803	32,465
13	GTO Operations Supervision & Engineering	Southern California Gas Company	850	4,508,565
14	System Control & Load Dispatch	Southern California Gas Company	851	775,906
15	Other Expenses	Southern California Gas Company	859	512,896
16	GTM Maintenance Mains	Southern California Gas Company	863	1,173,791
17	Operation Supervision and Engineering	Southern California Gas Company	870	3,986,154
18	Routine Leak Survey	Southern California Gas Company	874	60,884
19	TIMP-Meas & Reg STA - CG	Southern California Gas Company	877	37,877
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Distribution Other Expenses	Southern California Gas Company	880	173,458
3	GDM Maintenance Mains	Southern California Gas Company	887	138,212
4	Maintenance / Meters & Hse Reg	Southern California Gas Company	893	498,183
5	Meter Reading Expenses	Southern California Gas Company	902	169,491
6	Customer Records and Collection Expenses	Southern California Gas Company	903	2,454,827
7	Customer Assistance Expenses	Southern California Gas Company	908	621,381
8	Informational & Instructional Advertising Expenses	Southern California Gas Company	909	15,216
9	Outside Services Employed	Southern California Gas Company	923	55,054,161
10	Injuries and Damages	Southern California Gas Company	925	806,656

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

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
11	Employee Pension and Benefits	Southern California Gas Company	926	188,775
12	Regulatory Commission Expenses	Southern California Gas Company	928	2,256,525
13	Miscellaneous General Expense	Southern California Gas Company	930.2	153,022
14	Rents	Southern California Gas Company	931	1,565,189
15	Maintenance of General Plant	Southern California Gas Company	935	1,451,737
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20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 Column: a

1 (Rows 1-105)
All non-power goods and services provided by affiliated companies are billed to San Diego Gas and Electric at fully loaded cost.

2 (Rows 2-68)
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 Utility, this method uses the same four factors that appear in Multi-factor (basic), but calculates ratios for California utility business units only;
Multi-factor split, this method divides costs 50% to Utilities, 50% to Global. The Multi-factor (basic) percentages are the basis for the allocation between Southern California Gas Company and San Diego Gas and Electric, and between Global Business Units;
Multi-factor 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 and Electric, and between Global Business Units(EXCLUDES ONCOR);
12 executive cost centers allocated using the weighted average of the annual labor budget for departments that report to the respective executive;
Causal - Executive Security, this method accounts for the transportation services available to Corporate officers and considers their allocation methods in general. The CEO (retained) has one dedicated driver, while the other 3 drivers are available to other executives and assumes an even allocation of Utility, Global and additional retained;
Causal - Fire Insurance, this method allocates all costs for Fire Insurance based on miles of electrical lines per business unit;
Causal - Full Time Employee Equivalents, total Full Time Employee equivalents (FTE's) are used as the basis for allocation of most Human Resource departmental services provided on behalf of all the business units. The Sempra Energy Corporate Center FTE's are re-allocated by Multi-factor (basic) to result in a blended rate;
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 - 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 - 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 - 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 workload hours are re-allocated using Multi-factor (basic) resulting in a

blended percentage;
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 - 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 - Citizenship Engagement, this method uses the Multi-Factor Basic allocation as a starting point, then reduces the percentages to exclude a portion attributed to managing costs which are retained;
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 - 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 - 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 - Law Department, this allocation method is based on direct time charged by attorneys, paralegal and law clerks in the Archer timekeeping system during the previous Jan-Sep period. Hours for Sempra Energy Corporate Center are re-allocated by 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 - Audit US, this method is based on the Audit hours planned for each business unit in the coming year. The portion of services attributable to Sempra Energy Corporate Center is re-allocated using Multi-Factor basic method to result in a blended percentage for each business unit;
Causal - SOX, this allocation is a weighted average of the workload of each employee within SOX Compliance based on an annual time study. Sempra Energy Corporate Center workload hours are reallocated using Multi-Factor Basic, resulting in a blended percentage;
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 - 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 - Sempra HQ CSOC Depreciation, needs to be allocated by this method, San Diego Gas & Electric 76.7% other affiliates 22.7%;
Causal - Sacramento Office Depreciation, needs to be allocated by this method, San Diego Gas & Electric 50%, other affiliates 50%;
Causal - VP Tax, this allocation is a weighted average of the workload of each employee within the Tax department based on an annual time study. Parent workload hours are reallocated using Multi-Factor Basic, resulting in a blended percentage;

Causal - Cash Management, for the Cash Management department, the Director estimates percentages based on volumes and time involved in the business units funding activities;
Causal - Executive Benefits (Southern California Gas Company), direct restricted stock and stock options expense for Southern California Gas Company executives is allocated because some executives are shared by more than one business unit. The percentages reflect a weighted average of each executive's work distribution among business units;
Causal - Executive Benefits (San Diego Gas and Electric), direct restricted stock and stock options expense for San Diego Gas and Electric executives is allocated because some executives are shared by more than one business unit. The percentages reflect a weighted average of each executive's work distribution among business units;
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 - 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 - 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 - 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.

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

3 (Rows 70-105)
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 122 Southern California Gas Company cost centers. The following causal beneficial relationship information is a summary of the 30 varying methodologies used:
22 cost centers used a form of LAN ID counts to determine the shared allocation;
16 cost centers used a ratio of miles to pipe;
11 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department;
10 cost centers used a form of allocation of computer and/or server system and resource usage statistics;
8 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;
8 cost centers used a ratio of miles of pipe;
6 cost centers used a form of gas meter counts and service territory allocations;
4 cost centers used a form of departmental studies based on current year budgeted activities and/or dollars;
4 cost centers used a form of the existing current year Sempra Energy Corporate Center four factor multi factor allocation which includes weighted averages of operating revenue, operating expenses, gross plant and investment and Full Time Employee equivalent numbers;
3 cost centers use a form of workload distribution study;
3 cost centers used a study based on cases worked by both regulated and non-regulated companies;
3 cost centers used a method involving the number of full time equivalent employees benefited by the activity;
2 cost centers used a form of allocation based on gas flow throughput;
2 cost centers used a form of an employee matrix;
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 Full Time Employee equivalent statistics for support;
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 count of network sites;
there was one use by a cost center of each of the remaining allocation methodologies:
an internal department study based on volumes of items mailed and payments processed and the allocation of employee time; planned support level to Utilities;
the number of contracts written;
the number of interfaces implemented;
a mileage ratio applied to specific budgeted activity;
a unit of measurement of call volume;
an allocation using number of stakeholders at each utility;
ratio of active meters;
a workload study based on the number of claims processed over the last 5 years;
a meter ratio applied to specific budgeted activity;
the weighted average of gas revenues;
and, an allocation based on the number of end users.

4 (Row 106-133)
All non power goods and services provided by San Diego Gas and Electric are billed at fully loaded cost.

5 (Row 106)
Affiliate companies charged by San Diego Gas and Electric for less than $250,000 include: Sempra International South America, Sempra International Mexico.

6 (Rows 106-133)
Fully loaded costs include all direct expenses, indirect overheads and, where applicable, a labor premium required by the Enova/Pacific Enterprises Merger Decision (D.98-03-073) for shared service billing. The Merger Decision also requires San Diego Gas and Electric to charge employee transfer fees to an affiliated company. Shared service non-power goods and service support cost are based on allocation process methodologies for 108 San Diego Gas and Electric cost centers. The following causal-beneficial relationship information is a summary of the 18 varying methodologies used:

30 cost centers used a form of LAN ID counts to determine the shared allocation;
20 cost centers used a form of weighted average allocation of time by inherent knowledge of the manager/planner assessment within the cost center department;
18 cost centers used a form of an allocation of space study identifying building square footage assigned;
9 cost centers use a form of workload distribution study;
8 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;
4 cost centers used the existing current year Sempra Energy Corporate Center four factor multi-factor allocation which includes weighted averages of operating revenue, operating expenses, gross plant and investment and Full Time Employee equivalent numbers;
3 cost centers used a form of budgeted current year project assignments;
3 cost centers used a form of a count of network sites;
2 cost centers used a form of allocation of voice count statistics;
2 cost centers were charged 100% to Sempra Energy Corporate Center;
2 cost centers used a form of the number of contracts supported;
there was one use by a cost center of each of the remaining allocation methodologies:
an allocation of time by Vice President or Director's assessment of planned current year project assignments within the cost center, which is adjusted as necessary when current year projects begin or change and impact the current allocation and current years budgeted activities by Affiliate;
a form of Full Time Employee equivalent statistics for support;

the number of full-time equivalent employees benefited by the activity;
a unit of measure based on San Diego Gas & Electric and Southern California Gas call volume;
the number of user licenses available;
an allocation based on the number of applications used for DevSecOps;
and, a form of allocation of computer and/or server system and resource usage statistics.

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