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

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
PACIFIC GAS AND ELECTRIC COMPANY	**End of** 2018/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	02 Year/Period of Report End of 2018/Q4
03 Previous Name and Date of Change *(if name changed during year)* PACIFIC GAS AND ELECTRIC COMPANY / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 77 BEALE STREET, P.O BOX 770000, SAN FRANCISCO, CA 94177	
05 Name of Contact Person RACHEL PETERSEN	06 Title of Contact Person DIRECTOR, CORP ACCOUNTING
07 Address of Contact Person *(Street, City, State, Zip Code)* 77 BEALE STREET, Mail Code B7A, P.O BOX 770000, SAN FRANCISCO, CA 94177	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(415) 973-1700	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
DAVID THOMASON	DAVID THOMASON	04/16/2019
02 Title VP, CONTROLLER, UTILITY CFO		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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".

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.

David S. Thomason, Vice President, Controller, and CFO
77 Beale Street, B11H
San Francisco, CA 94105

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 – October 10, 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.

Electricity and natural gas distribution, electric generation, procurement, and transmission, and natural gas procurement, transportation, and storage.

State of California only.

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

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

CONTROL OVER RESPONDENT

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

Effective January 1, 1997, PG&E Corporation became the holding company of Pacific Gas and Electric Company.

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	Eureka Energy Company	Formerly managed	100	
2		the Utility's Utah coal		
3		venture. Currently holds		
4		part of the Marre Ranch		
5		property in San Luis		
6		Obispo County.		
7				
8	Midway Power, LLC	Formed to be the ownership	100	
9		entity for real estate and		
10		licenses for a suspended		
11		development project.		
12				
13	Natural Gas Corporation of California (NGC)	Entity used to amortize	100	
14		remaining Gas		
15		Exploration and		
16		Development Account		
17		assets.		
18				
19	FuelCo LLC	Formed to share costs and	50	1
20		reduce fuel acquisition		
21		costs.		
22				
23	Pacific Energy Fuels Company	Formed to own and	100	
24		finance the nuclear fuel		
25		inventory previously owned		
26		by Pacific Energy Trust		
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	Standard Pacific Gas Line Incorporated	Engaged in the transportation	85.71	
3		of natural gas in California.		
4		The Utility owns an 85.71%		
5		interest and Chevron Pipe		
6		Line Company owns the		
7		remaining 14.29% interest.		
8				
9				
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11				
12	Morro Bay Mutual Water Company	Formed to jointly hold	50	2
13		property rights in connection		
14		with the divestiture of the		
15		Morro Bay Power Plant.		
16				
17	Moss Landing Mutual Water Company	Formed to jointly hold	33	3
18		propert rights in connection		
19		with the divestiture of the		
20		Moss Landing Power Plant.		
21				
22	Alaska Gas Exploration Associates	Formed to explore,	100	4
23		develop, produce, acquire,		
24		and market oil and gas		
25		reserves in Alaska.		
26				
27				

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

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	STARS Alliance, LLC	Formed to increase efficiency	25	5
2		and reduce costs related to		
3		the operation of the members		
4		nuclear generation		
5		facilities.		
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Schedule Page: 103 Line No.: 19 Column: d

Members include: Union Electric Company d/b/a AmerenMO.
12/8/17 - Certificate of Withdrawal filed with the state of Texas

Schedule Page: 103.1 Line No.: 12 Column: d

Members include: Dynergy Moss Landing. Pacific Gas and Electric Company is one of 2 members of the non-profit mutual benefit corporation.

Schedule Page: 103.1 Line No.: 17 Column: d

Members include: Dynergy Moss Landing and Moon Glow Dairy. Pacific Gas and Electric Company is one of 3 members of the non-profit mutual benefit corporation.

Schedule Page: 103.1 Line No.: 22 Column: d

Currently inactive

Schedule Page: 103.2 Line No.: 1 Column: d

Members include: Arizona Public Service Company, Union Electric Company, d/b/a AmerenMO, and Wolf Creek Nuclear Operating Corporation. Pacific Gas and Electric Company has a 1/4 equity interest.

Waiting for confirmation of withdrawal from Texas.

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Senior VP, Human Resources and Chief Diversity Officer	Dinyar B. Mistry	504,167
2	Senior VP, Gas Operations	Jesus Soto, Jr.	474,333
3	Senior VP and Chief Ethics and Compliance Officer and	Julie M. Kane	470,197
4	Deputy General Council		
5	Senior VP and Chief Customer Officer	Loraine M. Giammona	461,667
6	Senior VP, Energy Supply and Policy	Steven Malnight	460,633
7	Senior VP, Electric Operation	Patrick M. Hogan	422,500
8	Senior VP, Energy Policy and Procurement	Fong Wan	410,833
9	Senior VP and Chief Information Officer	Kathleen B. Kay	387,333
10	Senior VP and Deputy General Counsel of the Utility	Janet C. Loduca	370,850
11	Vice President, Chief Financial Officer and Controller	David S. Thomason	320,833
12	Special Advisor	Nickolas Stavropoulos	618,667
13	Senior VP and Cheif Information Officer	Karen A. Austin	477,833
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Schedule Page: 104 Line No.: 6 Column: b

Mr. Malnight, formerly Senior VP, Strategy and Policy, became Senior VP, Energy Supply and Policy on September 1, 2018.

Schedule Page: 104 Line No.: 9 Column: b

Ms. Kay, formerly VP, Business Technology, became Senior VP and Chief Information Officer on September 1, 2018.

Schedule Page: 104 Line No.: 10 Column: b

Ms. Loduca, formerly VP and Deputy General Counsel, became Senior VP and Deputy General Counsel on December 1, 2018

Schedule Page: 104 Line No.: 12 Column: b

Mr. Stavropoulos, formerly President and Chief Operating Officer, became Special Advisor on September 1, 2018. Mr. Stavropoulos' employement ended October 1, 2018.

Schedule Page: 104 Line No.: 13 Column: b

Ms. Austin's employment ended November 1, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Lewis Chew ***	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Fred J. Fowler	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	Richard C. Kelly **	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
12		
13	Roger H. Kimmel	c/o PG&E Corporation
14		77 Beale Street, 32nd Floor
15		San Francisco, CA 94105
16		
17	Richard A. Meserve ***	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
20		
21	Forrest E. Miller ***	c/o PG&E Corporation
22		77 Beale Street, 32nd Floor
23		San Francisco, CA 94105
24		
25	Benito Minicucci	c/o PG&E Corporation
26		77 Beale Street, 32nd Floor
27		San Francisco, CA 94105
28		
29	Eric D. Mullins	c/o PG&E Corporation
30		77 Beale Street, 32nd Floor
31		San Francisco, CA 94105
32		
33	Rosendo G. Parra	c/o PG&E Corporation
34		77 Beale Street, 32nd Floor
35		San Francisco, CA 94105
36		
37		
38	Barbara L. Rambo ***	c/o PG&E Corporation
39		77 Beale Street, 32nd Floor
40		San Francisco, CA 94105
41		
42	Anne Shen Smith ***	c/o PG&E Corporation
43		77 Beale Street, 32nd Floor
44		San Francisco, CA 94105
45		
46	Geisha J. Williams	c/o PG&E Corporation
47		77 Beale Street, 32nd Floor
48		San Francisco, CA 94105

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] 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	NOT APPLICABLE	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

[ ] Yes
[X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1			NOT APPLICABLE		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1		NOT APPLICABLE		
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

PACIFIC GAS AND ELECTRIC COMPANY
IMPORTANT CHANGES DURING THE YEAR

For the Quarter Ended December 31, 2018

1. Changes in and important additions to franchise rights:

There are no changes in or additions to PG&E's franchise rights.

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies:

None.

3. Purchase or sale of an operating unit or system:

Sale:

None.

Purchase:

None.

4. Important leaseholds that have been acquired or given, assigned or surrendered:

None.

5. Important extension or reduction of transmission or distribution system:

Electric:

On February 8, 2018, the Crescent Switching Station was released to operations. This project, located in Fresno County, constructed a new 6 circuit breaker-and-a-half (BAAH) 70 kV Switching Station. This project was built to facilitate the interconnection of a 20 MW solar generation by San Joaquin 1A Solar to Pacific Gas and Electric Company's Helm – Stroud & Stroud Sw Sta – Schindler 70 kV Lines.

On February 15, 2018, the Midway Fault Duty Mitigation Project was released to operations. This project, located in Kern County, installed 9 ohm series reactors at the 230 kV side of Midway 500/230 kV Transformer Banks 11, 12 and 13. This project was built to mitigate excessive fault duty, which was projected to increase beyond the specified safe limits as a result of various generation interconnection projects at Midway Substation.

On April 17, 2018, the Warnerville-Wilson 230 kV Series Reactor Project was released to operations. This project, located in Fresno County, installed 230 kV multi-step series reactors totaling 50.5 Ohms at the Wilson Substation on the Warnerville-Wilson 230 kV line. This project was built to provide additional transmission capacity and reliability to serve electric customers, and to address potential overload conditions in Central California/Fresno area.

On July 15, 2018, Cheney Substation was removed from operations. This project, located in Fresno County, decommissioned the 115 kV Substation and permanently tied together the Cheney #1 & Cheney #2 115 kV lines to bypass the station. The addition of a new distribution transformer with associated bus and breakers at Panoche Substation and electric service transfer of all Cheney distribution feeders to Panoche Substation resulted in the full decommissioning of Cheney Substation to improve service reliability and operational flexibility in northwest Fresno County.

On August 7, 2018, the Stroud Switching Station was removed from operations. This project, located in Fresno County, decommissioned the 70 kV Switching Station and constructed a new 6 circuit breaker-and-a-half (BAAH) 70 kV Crescent Switching Station. This project was built to facilitate the interconnection of a 20 MW solar generation by San Joaquin 1A Solar to Pacific Gas and Electric Company's Helm - Crescent Sw Sta & Crescent Sw Sta - Schindler 70 kV Lines.

Gas:

None.

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 maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee:**

a) Financings:

There were no Long-Term borrowings during the quarter ending December 31, 2018.

Long-term borrowings are authorized by the California Public Utilities Commission ("CPUC") Decision No. 15-01-030.

There were no Short-Term borrowings during the quarter ending December 31,2018.

Short-term borrowings are authorized by CPUC Decision No. 09-05-002.

b) Bank Credit Facilities:

At December 31, 2018, the Utility had $80 million of letters of credit outstanding, no commercial paper outstanding, and $2.9 billion of borrowings under its revolving credit facility. Short-term borrowings are authorized by CPUC Decision No. 09-05-002.

c) Surety Bonds and Financial Guarantees Backed by Insurance:

From October 01, 2018 to December 31, 2018, $ 25,000.00 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of December 31, 2018, there was a total of $119,696,568.25 in long-term surety bond obligations outstanding.

d) Capital Support:

CPUC Decision No. 91-12-057 (as modified by Decision No. 99-04-068) authorized the Utility to provide capital support to regulated and unregulated subsidiaries. At December 31, 2018, the Utility has no outstanding future capital commitments to unregulated subsidiaries and affiliates.

e) Preferred stock repayments:

None.

7. Changes in articles of incorporation or amendments to charter. Explain the nature and purpose of such changes or amendments:

None.

8. State the estimated annual effect and nature of any important wage scale changes during the period:

None.

9. State briefly the status of any materially important legal proceedings pending at the end of the period and the results of any such proceedings culminated during the period:

Refer to Part I, Item 3 in PG&E Corporation and the Utility's joint Annual Report on Form 10-K for the year ended December 31, 2018, which describes certain legal proceedings pursuant to Item 103 of Regulation S-K of the Securities Exchange Act of 1934, as amended. Four copies of the Form 10—K report are filed in accordance with Instruction III(c) of Instructions For Filing the FERC Form No. 1.

10. Describe briefly any materially important transactions of the not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest:

"Five Percent Owners"

During the fourth quarter of 2018, three beneficial owners of at least 5 percent of PG&E Corporation common stock as of December 31, 2017 provided asset management services to PG&E Corporation, Pacific Gas and Electric Company ("Utility"), and

related entities: BlackRock,?Inc. ("BlackRock"), T. Rowe Price Associates Inc.

("Price Associates"), and the Vanguard Group ("Vanguard"). These entities were identified based solely on a review of Schedule 13Gs (or any amendments) filed with the Securities and Exchange Commission by February 15, 2018.

Specifically, these entities provided asset management services to various trusts associated with PG&E Corporation's and the Utility's employee benefit plans, to the Utility's nuclear decommissioning trusts, to the trusts securing benefits in the event of a change in control, and the PG&E Corporation Foundation. In each of these cases (with the exception of Vanguard), the services were initiated before the entity

became a 5?percent shareholder. In each of these cases, the services are subject to

terms comparable to those that could be obtained in arm's-length dealings with an unrelated third party. PG&E Corporation and the Utility expect that these entities will continue to provide similar services and products in the future, in the normal course of business operations.

During 2018, each of these parties is expected to provide services in excess of the $120,000 disclosure threshold set forth in SEC Reg. S-K, Item 404(a).

"Immediate Family Members"

Kathy Thomason is employed by the Utility as a Business Finance Analyst, Expert. She is the wife of David Thomason, who is Vice President, Chief Financial Officer, and Controller of the Utility and an executive officer of the Utility. Ms. Thomason is, therefore, an "immediate family member" for purposes of SEC related person transaction disclosure rules. While Ms. Thomason is employed with the Utility, she will receive salary, short-term incentive awards, and other cash compensation and benefits consistent with the Utility's standard compensation practices and policies.

We expect that the value of payments to Ms. Thomason for the period January 2018 through March 2019 (assuming she remains employed with the Utility during that period) will be close to the $120,000 disclosure threshold set forth in SEC Reg S-K. Item 404(a).

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 to 1 to 11 above, such notes may be included on this page.**

Not applicable.

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:**

Directors

The following individual was elected as a Director of the Utility:

- Benito Minicucci, Director

The following individual is no longer a Director of the Utility:

- Nickolas Stavropoulos, Director

Officers

The following individuals became an officer of the Utility:

• Michael A. Lewis, Vice President Electric Distribution Operations

The following individual's titles changed:

• Nickolas Stavropoulos, Special Advisor to the Utility (formerly President and Chief Operating Officer)

• Janet C. Loduca, Senior Vice President and Deputy General Counsel(formerly Vice President and Deputy General Counsel)

• Kathleen B. Kay, Senior Vice President and Chief Information Officer (formerly Vice President,Business Technology)

• Steven E. Malnight, Senior Vice President, Energy Supply and Policy (formerly Senior Vice President, Strategy and Policy)

• Barry D. Anderson, Vice President, Wildfire Resiliency and Emergency Management (formerly Vice President, Electric Distribution)

• Jon A. Franke, Vice President, Safety and Health and Chief Safety Officer (formerly Vice President, Power Generation)

• Gun S. Shim, Vice President and Chief Procurement Officer (formerly Vice President, Supply Chain Management)

• Sumeet Singh, Vice President, Community Wildfire Safety Program (formerly Vice President, Gas Asset and Risk Management)

The following individual is no longer an officer of the Utility:

• Nickolas Stavropoulos, Special Advisor to the Utility

• Barry D. Anderson, Vice President, Wildfire Resiliency and Emergency Management

• Karen A. Austin, Senior Vice President and Chief Information Officer

• Timothy Fitzpatrick, Vice President, Corporate Relations and Chief Communications Officer

• John C. Higgins, Vice President, Safety & Health, and Chief Safety Office

Major Security Holders

Changes to the major holders of the Utility's First Preferred Stock are as follows:

Cede & Co., C/O DTCC-Transfer Operation Dept., 570 Washington Blvd Floor 1, Jersey City, NJ 08857, increased its share ownership from 9,556,157 shares as of December 31, 2017 to 9,632,045 shares as of December 31, 2018. (Approximately 93 percent of the total preferred shares outstanding).

Dividend Payments

Refer to Note X, Equity of the Notes to Financial Statements on page XXX of the FERC Form 4-Q.

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:

Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	86,967,343,203	81,000,792,691
3	Construction Work in Progress (107)	200-201	2,562,027,669	2,470,588,868
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		89,529,370,872	83,471,381,559
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	37,353,599,037	35,680,789,356
6	Net Utility Plant (Enter Total of line 4 less 5)		52,175,771,835	47,790,592,203
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	233,949,233	261,763,030
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		427,381,622	416,084,176
10	Spent Nuclear Fuel (120.4)		2,359,998,526	2,265,141,307
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,630,936,779	2,505,050,242
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		390,392,602	437,938,271
14	Net Utility Plant (Enter Total of lines 6 and 13)		52,566,164,437	48,228,530,474
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		55,907,325	55,907,325
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		29,171,933	30,929,381
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	50,082,345	48,859,887
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	355,147,460	195,017,512
24	Other Investments (124)		10,942	10,942
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,729,720,970	2,863,247,030
29	Special Funds (Non Major Only) (129)		545,313,624	553,022,543
30	Long-Term Portion of Derivative Assets (175)		165,299,922	102,130,395
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,874,747,196	3,793,217,690
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		71,327,413	57,718,289
36	Special Deposits (132-134)		6,886,597	6,951,064
37	Working Fund (135)		147,415	146,305
38	Temporary Cash Investments (136)		1,220,000,000	385,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,273,685,556	1,368,326,668
41	Other Accounts Receivable (143)		3,128,236,294	1,294,343,299
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		56,198,372	64,476,202
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		34,585,453	21,355,991
45	Fuel Stock (151)	227	1,566,341	1,375,066
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	442,660,412	365,624,133
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	396,185,501	419,851,065

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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		355,147,460	195,017,512
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		108,986,991	113,465,206
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		305,102,547	227,100,005
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		3,281,579	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		1,000,028,952	945,999,103
62	Miscellaneous Current and Accrued Assets (174)		102,494,054	14,376,070
63	Derivative Instrument Assets (175)		208,704,537	129,373,589
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		165,299,922	102,130,395
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)		7,727,233,888	4,989,381,744
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		124,158,942	131,251,529
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	68,809,105	3,683,889
72	Other Regulatory Assets (182.3)	232	5,845,482,579	5,018,800,793
73	Prelim. Survey and Investigation Charges (Electric) (183)		162,540	82,918
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)		174,950	3,237,868
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	26,073,137	55,551,664
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)		93,374,528	97,418,150
82	Accumulated Deferred Income Taxes (190)	234	5,025,590,626	1,728,161,422
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		11,183,826,407	7,038,188,233
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		75,407,879,253	64,105,225,466

Schedule Page: 110 Line No.: 82 Column: c

See page 122-123 for details on the remeasurement of excess deferred income taxes in 2017, as a result of teh Tax Cuts and Jobs Act of 2017.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	1,321,874,045	1,321,874,045
3	Preferred Stock Issued (204)	250-251	257,994,575	257,994,575
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,805,194,230	1,805,194,230
7	Other Paid-In Capital (208-211)	253	6,780,547,928	6,735,547,928
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	6,916,899	6,916,899
10	(Less) Capital Stock Expense (214)	254b	28,951,886	28,951,886
11	Retained Earnings (215, 215.1, 216)	118-119	2,884,435,643	9,712,977,993
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-58,010,567	-56,608,615
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)	-986,708	6,290,667
16	Total Proprietary Capital (lines 2 through 15)		12,955,180,361	19,747,402,038
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	18,387,100,000	18,032,100,000
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)		13,404,631	14,860,769
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		76,509,009	80,156,440
24	Total Long-Term Debt (lines 18 through 23)		18,323,995,622	17,966,804,329
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		9,012,994	17,990,411
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		14,641,225,188	1,003,439,991
29	Accumulated Provision for Pensions and Benefits (228.3)		2,040,734,062	2,025,769,027
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,434,278,826	1,039,213,260
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		88,211,315	57,007,082
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		5,994,342,481	4,899,104,864
35	Total Other Noncurrent Liabilities (lines 26 through 34)		24,207,804,866	9,042,524,635
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		3,135,000,001	800,000,001
38	Accounts Payable (232)		2,651,188,423	2,402,987,144
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		38,940,769	22,050,491
41	Customer Deposits (235)		235,799,401	231,822,866
42	Taxes Accrued (236)	262-263	360,498,405	433,396,782
43	Interest Accrued (237)		234,978,351	220,498,682
44	Dividends Declared (238)		16,235,704	2,319,386
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)		30,123,144	34,679,077
48	Miscellaneous Current and Accrued Liabilities (242)		411,182,395	692,014,936
49	Obligations Under Capital Leases-Current (243)		1,682,542	12,512,046
50	Derivative Instrument Liabilities (244)		109,769,265	88,095,705
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		88,211,315	57,007,082
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)		7,137,187,085	4,883,370,034
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		359,612,163	423,431,367
57	Accumulated Deferred Investment Tax Credits (255)	266-267	108,383,883	114,033,790
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	227,311,425	208,094,334
60	Other Regulatory Liabilities (254)	278	3,496,782,247	3,876,105,498
61	Unamortized Gain on Reaquired Debt (257)		716,895	862,920
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	307	307
63	Accum. Deferred Income Taxes-Other Property (282)		7,973,787,674	7,394,379,151
64	Accum. Deferred Income Taxes-Other (283)		617,116,725	448,217,063
65	Total Deferred Credits (lines 56 through 64)		12,783,711,319	12,465,124,430
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		75,407,879,253	64,105,225,466

Schedule Page: 112 Line No.: 60 Column: c

See page 122-123 for details on the remeasurement of excess deferred income taxes in 2017, as a result of teh Tax Cuts and Jobs Act of 2017.

Schedule Page: 112 Line No.: 64 Column: c

See page 122-123 for details on the remeasurement of excess deferred income taxes in 2017, as a result of teh Tax Cuts and Jobs Act of 2017.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	17,337,575,325	17,477,273,258		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	21,090,929,970	9,354,586,213		
5	Maintenance Expenses (402)	320-323	1,698,634,311	1,473,178,225		
6	Depreciation Expense (403)	336-337	2,708,898,400	2,520,662,622		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	323,697,675	332,006,690		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		2,113,770	116,111		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)			-629,795		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	632,365,632	592,757,485		
15	Income Taxes - Federal (409.1)	262-263	4,236,134	-10,252,653		
16	- Other (409.1)	262-263	13,470,011	108,797,147		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	-864,342,003	-208,874,972		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,478,874,964	-718,959,065		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		580,002	13,324,707		
21	Losses from Disp. of Utility Plant (411.7)			270,691		
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)		23,130,548,934	14,868,252,122		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		-5,792,973,609	2,609,021,136		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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
13,086,062,407	13,283,628,752	4,251,512,918	4,193,644,506			2
						3
18,919,388,088	7,014,966,243	2,171,541,882	2,339,619,970			4
1,071,056,781	959,259,070	627,577,530	513,919,155			5
2,121,424,880	1,980,795,695	587,473,520	539,866,927			6
						7
225,407,275	237,269,411	98,290,400	94,737,279			8
						9
2,113,770	116,111					10
						11
	-629,795					12
						13
475,321,400	449,084,479	157,044,232	143,673,006			14
4,236,133	-10,252,653	1				15
112,005,442	105,092,246	-98,535,431	3,704,901			16
-738,531,553	-275,512,268	-125,810,450	66,637,296			17
2,388,974,856	-713,495,770	89,900,108	-5,463,295			18
						19
580,002	2,517,330		10,807,377			20
	270,691					21
						22
						23
						24
19,802,867,358	11,171,437,670	3,327,681,576	3,696,814,452			25
-6,716,804,951	2,112,191,082	923,831,342	496,830,054			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		-5,792,973,609	2,609,021,136		
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)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	42,609	-3,103,044		
37	Interest and Dividend Income (419)		74,371,716	30,022,985		
38	Allowance for Other Funds Used During Construction (419.1)		129,009,681	89,256,337		
39	Miscellaneous Nonoperating Income (421)		3,071,748	5,679,371		
40	Gain on Disposition of Property (421.1)		315,099	6,657,171		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		206,810,853	128,512,820		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		12,499,780	10,944,162		
46	Life Insurance (426.2)					
47	Penalties (426.3)		5,324,520	24,386,884		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		13,096,115	13,443,474		
49	Other Deductions (426.5)		255,846,898	301,635,298		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		286,767,313	350,409,818		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	486,744	362,370		
53	Income Taxes-Federal (409.2)	262-263	8,062,576	71,582,687		
54	Income Taxes-Other (409.2)	262-263	-29,809,600	-39,875,243		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	33,169,360	-40,539,809		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	-25,839,617	158,562,363		
57	Investment Tax Credit Adj.-Net (411.5)		-5,649,907	-14,378,049		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		32,098,790	-181,410,407		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-112,055,250	-40,486,591		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		791,084,121	806,065,887		
63	Amort. of Debt Disc. and Expense (428)		29,043,258	27,416,689		
64	Amortization of Loss on Reaquired Debt (428.1)		19,003,995	18,399,376		
65	(Less) Amort. of Premium on Debt-Credit (429)		818,824	1,963,283		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		146,025	146,025		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		127,444,511	65,165,469		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		52,532,426	37,674,326		
70	Net Interest Charges (Total of lines 62 thru 69)		913,078,610	877,263,787		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-6,818,107,469	1,691,270,758		
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)		-6,818,107,469	1,691,270,758		

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

Includes interdepartmental operating revenues in Line 2 and operations expenses in Line 4 for the twelve-month period ended December 31:

	2018		2017	
	Revenues	Expenses	Revenues	Expenses
Electric	46,634,494	81,028,298	44,421,522	71,545,053
Gas	208,166,556	173,772,752	189,093,175	161,969,645
Total	254,801,050	254,801,050	233,514,697	233,514,697

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

Line 2, Col e — Includes interdepartmental operating revenues in Line 2 and operations expenses in Line 4 for the three-month period ended December 31:

	Current QTR		Prior QTR	
	Revenues	Expenses	Revenues	Expenses
Electric	16,865,517	29,006,393	15,870,676	25,298,077
Gas	70,074,831	57,933,955	64,403,078	54,975,679
Total	86,940,348	86,940,348	80,273,754	80,273,754

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

Refer to the footnote for Line 2, column c.

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

Refer to the footnote for Line 2, column e.

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		9,450,613,073	8,576,546,935
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Reclassify stranded tax effects resulting from the 2017 Tax Cuts			
6	and Jobs Act from Accumulated Other Comprehensive Income	219	2,079,484	
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		2,079,484	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		-6,818,150,078	1,694,373,802
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19	Reserves for excess earnings on FERC hydroelectric			
20	project licenses pursuant to Federal Power Act Section 10 (d)	215	-23,656,015	(23,778,373)
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-23,656,015	(23,778,373)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25	Preferred Dividends Declared	238		(13,916,352)
26				
27	Accrued Preferred Dividends Requirement	238	-13,916,318	
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-13,916,318	(13,916,352)
30	Dividends Declared-Common Stock (Account 438)			
31				
32	Common Stock Dividends Declared	234		(784,000,000)
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(784,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,444,562	1,387,061
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,598,414,708	9,450,613,073
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40	Reserves for excess earnings on FERC hydroelectric			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	project licenses pursuant to Federal Power Act Section 10 (d)		23,656,015	23,778,373
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		23,656,015	23,778,373
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		262,364,920	238,586,547
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		286,020,935	262,364,920
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,884,435,643	9,712,977,993
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-56,608,615	(52,118,510)
50	Equity in Earnings for Year (Credit) (Account 418.1)		42,609	(3,103,044)
51	(Less) Dividends Received (Debit)			
52	Utility subsidiary earnings reflected in operations and maintenance accounts		-1,444,561	(1,387,061)
53	Balance-End of Year (Total lines 49 thru 52)		-58,010,567	(56,608,615)

Schedule Page: 118 Line No.: 25 Column: d

The following is the detail of dividends declared on First Preferred Stocks for the year ended December 31, 2017:

Class of Stock	No. of Shares	Annual Dividends Per Share	Total Declared
6.00% Cumulative, Non-Redeemable	4,211,662	$1.500	$ 6,317,510
5.50% Cumulative, Non-Redeemable	1,173,163	1.375	1,613,105
5.00% Cumulative, Non-Redeemable	400,000	1.250	500,000
5.00% Cumulative, Redeemable	1,778,172	1.250	2,222,718
5.00% Cumulative, Redeemable - Series A	934,322	1.250	1,167,907
4.80% Cumulative, Redeemable	793,031	1.200	951,637
4.50% Cumulative, Redeemable	611,142	1.125	687,537
4.36% Cumulative, Redeemable	418,291	1.090	455,938
Total			$13,916,352

Schedule Page: 118 Line No.: 27 Column: c

There were no preferred dividends declared for the period ended December 31, 2018.

However, since preferred stocks are cumulative, preferred dividend accruals were recorded. The liability is shown in Line 44, Dividends Declared, on page 112 of the balance sheet.

The following is the detail of accrued dividends on First Preferred Stocks for the period ended December 31, 2018:

Class of Stock	No. of Shares	Annual Dividends Per Share	Total Accrued
6.00% Cumulative, Non-Redeemable	4,211,662	$1.500	$ 6,317,492
5.50% Cumulative, Non-Redeemable	1,173,163	1.375	1,613,099
5.00% Cumulative, Non-Redeemable	400,000	1.250	500,000
5.00% Cumulative, Redeemable	1,778,172	1.250	2,222,715
5.00% Cumulative, Redeemable - Series A	934,322	1.250	1,167,903
4.80% Cumulative, Redeemable	793,031	1.200	951,637
4.50% Cumulative, Redeemable	611,142	1.125	687,535
4.36% Cumulative, Redeemable	418,291	1.090	455,937
Total			$13,916,318

Schedule Page: 118 Line No.: 32 Column: d

This represents dividends declared on Common Stock to PG&E Corporation for the year ended December 31, 2017.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	-6,818,107,469	1,691,270,758
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	3,034,709,845	2,852,785,423
5	Disallowed Capital Expenditures	-44,798,404	47,398,938
6	Amortization of Unamortized Loss or Gain on Reacquired Debt	18,857,970	17,613,914
7	Amortization of Expenses, Discount and Premium - Long Term Debt	19,699,655	18,098,551
8	Deferred Income Taxes (Net)	-2,538,903,619	1,083,992,255
9	Investment Tax Credit Adjustment (Net)	-5,649,907	-14,378,049
10	Net (Increase) Decrease in Receivables	-1,853,762,002	39,678,174
11	Net (Increase) Decrease in Inventory	-72,749,339	-16,973,849
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	348,769,957	505,815,231
14	Net (Increase) Decrease in Other Regulatory Assets	-715,545,561	-981,763,074
15	Net Increase (Decrease) in Other Regulatory Liabilities	-16,151,084	609,750,902
16	(Less) Allowance for Other Funds Used During Construction	129,009,681	89,256,337
17	(Less) Undistributed Earnings from Subsidiary Companies	-1,401,952	-4,490,105
18	Other (provide details in footnote):	13,476,022,102	129,518,306
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	4,704,784,415	5,898,041,248
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-6,564,592,641	-5,596,719,659
27	Gross Additions to Nuclear Fuel	-78,340,868	-131,760,000
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-129,009,681	-89,256,337
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-6,513,923,828	-5,639,223,322
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	22,233,335	25,953,577
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,611,620	-3,512,324
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Payments to Advances by Assoc. and Subsidiary Companies		-3,253,555
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Net (Increase) Decrease in Restricted Cash		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Proceeds from nuclear decommissioning trust investments	1,411,689,770	1,291,749,504
55	Purchases of nuclear decommissioning trust investments and other	-1,484,791,279	-1,322,693,283
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-6,566,403,622	-5,650,979,403
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	792,991,500	2,713,526,928
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	2,334,796,430	-221,734,268
67	Other (provide details in footnote):		
68	Equity contribution from PG&E Corporation	45,000,000	455,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	3,172,787,930	2,946,792,660
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-445,000,000	-1,445,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Customer Advances for Construction	4,227,505	-7,963,753
78	Net Decrease in Short-Term Debt (c)		-500,000,000
79	Other	-21,850,462	-68,324,365
80	Dividends on Preferred Stock		-13,916,352
81	Dividends on Common Stock		-784,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	2,710,164,973	127,588,190
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	848,545,766	374,650,035
87			
88	Cash and Cash Equivalents at Beginning of Period	449,815,658	75,165,623
89			
90	Cash and Cash Equivalents at End of period	1,298,361,424	449,815,658

Schedule Page: 120 Line No.: 5 Column: b

This primarily consists of a $14M true-up of the PSEP Plant reserve and a $41M true-up of the TIMP Plant reserve based on the 2018 forecast, offset by the Accumulated depreciation impacts and additional write-offs.

Schedule Page: 120 Line No.: 18 Column: b

This consists of the following:

	2018	2017
(Increase) Decrease in Other Working Capital	$ (438,463,686)	$ 105,668,533
Increase (Decrease) - Other Noncurrent Liabilities*	13,777,892,530	(191,024,518)
Others		
Nuclear Fuel Lease Amortization	125,886,537	123,258,253
Payment on capital lease obligation	(1,921,000)	(18,262,296)
Collateral Adjustment	12,592,010	(13,675,915)
Bad Debt Expense	35,471,842	54,533,182
Tax benefit on stock option exercises (shortfall)	(11,642,424)	24,464,196
Other-net**	(23,793,706)	44,556,871
Total	$ 13,476,022,103	$ 129,518,306

*This primarily consists of a $14 billion increase to the "Accumulated Provision" balances (accounts 228.2, 228.3, 228.4 and 229) corresponding to the amount charged for the lower end of the range of the Utility's reasonably estimated losses related to the 2017 Northern California wildfires and the 2018 Camp fire. This increase is partially offset by $109 million of asset retirement obligation work performed.

**This primarily consists of allowances related to GHG.

Schedule Page: 120 Line No.: 18 Column: c

See footnote in column (b), Line 18.

Schedule Page: 120 Line No.: 48 Column: c

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows – Restricted Cash (Topic 230), which amends the existing guidance relating to the disclosure of restricted cash and restricted cash equivalents on the statement of cash flows. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning and end of period total amounts shown on the statement of cash flows. Previously, changes in restricted cash were reported within cash flows from investing activities. The Utility applied the requirements on a retrospective basis when the ASU became effective on January 1, 2018.

The retrospective adjustments to the Statement of Cash Flows for the Utility resulted in an increase to Net cash used in investing activities of $186,641, an increase to Cash and cash equivalents at January 1 by $6,764,423, and an increase to Cash, cash equivalents and restricted cash at December 31 by $6,951,064 for the year ended December 31, 2017.

Schedule Page: 120 Line No.: 55 Column: b

"Other" amounts presented on this line consist of the following:

	2018	2017

Purchases of Nuclear Decommissioning Trust Investments	$ (1,484,791,279)	$ (1,322,771,298)
Decrease in other investments	-	78,015
Total	$ (1,484,791,279)	$ (1,322,693,283)

Schedule Page: 120 Line No.: 55 Column: c

See footnote in column (b), Line 55.

Schedule Page: 120 Line No.: 79 Column: b

This consists of the following:

	2018	2017
Increase (Decrease) in customer deposits	$ 3,903,352	$ 469,325
Debt Issuance Costs - ST Borrowings	(25,000)	(3,268,176)
Employee taxes paid for withheld shares	(10,580,685)	(65,525,514)
Premium paid for early redemption of long-term debt	(15,148,129)	
Total	$ (21,850,462)	$ (68,324,365)

Schedule Page: 120 Line No.: 79 Column: c

See footnote in column (b), Line 79.

Schedule Page: 120 Line No.: 88 Column: c

This amount has been adjusted to reflect the retrospective adjustment for ASU 2016-18. See footnote in column (c), line 48 for additional discussion.

Schedule Page: 120 Line No.: 90 Column: b

This consists of the following:

	2018	2017
Cash (131)	$ 71,327,413	$ 57,718,289
Special Deposits (132-134)*	6,886,597	6,951,064
Working Funds (135)	147,415	146,305
Temporary Cash Investment (136)	1,220,000,000	385,000,000
Total	$1,298,361,425	$ 449,815,658

Supplemental disclosures of cash flow information (in millions):

Cash paid for:		
Interest (net of amounts capitalized)	$ (773)	$ (781)
Income taxes paid (refunded), net	(59)	162
Supplemental disclosures of noncash investing and financing activities:		
Capital expenditures financed through accounts payable	368	501

*Per ASU 2016-18, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning and end of period total amounts shown on the statement of cash flows. See footnote in column (c), line 48 for further discussion.

Schedule Page: 120 Line No.: 90 Column: c

See footnote in column (b), Line 90.

NOTES TO FINANCIAL STATEMENTS

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

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

Introduction:

The notes below are excerpts from PG&E Corporation and the Utility's combined Report on Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission ("SEC") on February 28, 2019. The following disclosures contain information in accordance with SEC reporting requirements. As such, due to the differences between FERC and SEC reporting requirements, certain amounts disclosed in the following notes may not agree to balances in the FERC financial statements.

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The primary differences from the Utility's GAAP basis financial statements as presented in the Form 3-Q are that (1) subsidiaries are not consolidated and are shown under the equity method of accounting, (2) deferred income tax assets and liabilities are not offset against each other but are shown as separate items on the balance sheet, are long-term, and exclude the impact of uncertain temporary tax positions, (3) cost of removal is reported in accumulated depreciation for FERC reporting purposes (GAAP requires that cost of removal be classified as a regulatory liability), (4) there is no current liability classification of the current portion of long-term debt for FERC reporting, (5) there is no reclassification of balancing accounts from current assets to current liabilities for FERC reporting, (6) interdepartmental revenues and expenses between electric and gas operations of the Utility are not eliminated for FERC reporting, (7) penalties and disallowances are reported in other income deductions for FERC reporting, and (8) payments on capital lease obligations are disclosed in operating activities in the statement of cash flows, (9) debt issuance costs are not deducted from the carrying amount of that debt liability for FERC reporting, (10) there is no current liability classification of the current portion of accumulated provision for injuries and damages for FERC reporting, and (11) FERC reporting does not reclass non-service costs related to pension benefits on the income statement pursuant to ASU 2017-07.

Subsequent Events:

On January 16, 2019 the FERC approved the use of Account 439 (Docket No. AC19-19-000), Adjustments to Retained Earnings, to record a cumulative-effect adjustment to retained earnings in order to address the stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act), and to implement Accounting Standards Update (ASU) No. 2018-02.2. PG&E Corporation and the Utility elected to adopt this treatment as of December 31, 2018.

Management has evaluated the impact of events occurring after December 31, 2018 up to February 28, 2019, the date that Pacific Gas and Electric Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 16, 2019. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Energy Storage Assets (FERC Order No. 784):

The following disclosure has been included to comply with accounting and reporting guidance issued by the FERC for new electric storage technologies as a result of FERC Order No. 784.

Energy Plant Account

Energy storage assets totaled $32,142,500 at December 31, 2018, all of which is recorded in account 363 in accordance with FERC Order No. 784.

Power Purchased Account

Energy storage-related purchased power costs totaled ($220,207) for the year ended December 31, 2018, all of which is recorded in account 555.1 in accordance with FERC Order No. 784.

Operation and Maintenance Expense Accounts

Energy storage-related operating expenses totaled $0 for the year ended December 31, 2018, of which $0 is recorded in account 582 and $0 is recorded in account 588. Amounts associated with distribution functional use would have been recorded in account 584.1 and amounts associated with production functional use would have been recorded in account 548.1, in accordance with FERC Order No. 784. Please see table below.

Energy storage-related maintenance expenses totaled $185,192 for the year ended December 31, 2018, of which $0 is recorded in account 570 and $185,192 is recorded in account 592. Amounts associated with distribution functional use would have been recorded in account 592.2 and amounts associated with production functional use would have been recorded in account 553.1, in accordance with FERC Order No. 784. Please see table below.

Other Expense Accounts

Energy storage-related employee pension and benefits expenses are recorded in account 926 in the amount of $0.

Energy storage-related payroll tax expenses are recorded in account 408.1 in the amount of $0.

The following information to be reported in the newly adopted schedule pages 419-420 can be submitted as part of pages 122-123:

Energy Storage Operations (Small Plants)

Line no.	Name of Energy Storage Project	Functional classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Vaca-Dixon	Production	Vacaville, CA	$11,286,007	$0	$70,271	$0	($220,207)	$0
2	Hitachi	Distribution	San Jose, CA	$20,856,493	$0	$96,323	$0	$0	$0
3	Browns Valley	Distribution	Marysville, CA	$0	$0	$18,598	$0	$0	$0
Totals				**$32,142,500**	**$0**	**$185,192**	**$0**	**($220,207)**	**$0**

Accumulated Deferred Income Taxes:

The Tax Cuts and Jobs Act of 2017 (“the Tax Act”) reduced the federal income tax rate from 35% to 21% beginning on January 1, 2018. The reduction in tax rate caused a remeasurement of deferred tax assets and liabilities by $4.5 billion comprising of $1.6 billion reduction in flow through net excess deferred tax liabilities and $2.9 billion reduction in normalized net excess deferred tax liabilities. Based on the estimate of the amount of excess deferred taxes expected to reduce future customer rates, the Utility recorded an increase in regulatory liabilities of approximately $5.6 billion, which includes the $4.5 billion reduction in net excess deferred tax liabilities and an additional $1.1 billion in regulatory liabilities representing revenue reduction due to customers for previously collected income taxes. The Utility also recorded a $1.1 billion deferred tax asset related to the regulatory liability.

The following table shows the results of the remeasurement of excess deferred income taxes in 2017 and the FERC accounts affected:

Increase/(Decrease) - in millions

Jurisdiction	Account 254	Account 190	Account 282	Account 283
FERC	$1,283	$(189)	$(1,472)	-

CPUC	4,294	(492)	(4,767)	(19)
Total	$5,577	$(681)	$(6,239)	$(19)

The following table summarizes the amount of excess deferred income taxes that is considered protected and unprotected as of December 31, 2018 and 2017. Excess deferred income taxes have been amortized in Accounts 401.1 and 411.1 in 2018.

In millions

Jurisdiction	12/31/2018	12/31/2017	Amortization Period
FERC - Protected	$753	$766	Regulated book life of the underlying plant - 15 to 75 years
FERC - Unprotected	156	158	Subject to approval
Total – FERC	$909	$924	
CPUC - Protected	$2,684	$2,765	
CPUC - Unprotected	(799)	(820)	Regulated book life of the underlying plant -5 to 120 years
Total - CPUC	$1,855	$1,945	Subject to approval
Total	$2,794	$2,869	

The Utility filed the estimated revenue impact of the Tax Act with the CPUC and FERC in 2018. The Utility has not received final regulatory decisions as of December 31, 2018

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

Organization and Basis of Presentation

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's wildfire-related liabilities, legal and regulatory contingencies, environmental remediation liabilities, insurance receivables, regulatory assets and liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows during the period in which such change occurred.

Chapter 11 Filing and Going Concern

The accompanying Consolidated Financial Statements have been prepared on a going concern basis, which contemplates the continuity of operations, the realization of assets and the satisfaction of liabilities in the normal course of business. However, as a result of the challenges that are further described below, such realization of assets and satisfaction of liabilities are subject to uncertainty. PG&E Corporation and the Utility are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. See Note 13 below. Uncertainty regarding these matters raises substantial doubt about PG&E Corporation's and the Utility's abilities to continue as going concerns. PG&E Corporation and the Utility have determined that commencing reorganization cases under Chapter 11 is necessary to restore PG&E Corporation's and the Utility's financial stability to fund ongoing operations and provide safe service to customers. However, there can be no assurance that such proceedings will restore PG&E Corporation's and the Utility's financial stability. On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. See Note 15 below. The Consolidated Financial Statements do not include any adjustments that might be necessary should PG&E Corporation and the Utility be unable to continue as going concerns.

Pursuant to Chapter 11, PG&E Corporation and the Utility retain control of their assets and are authorized to operate their business as debtors in possession while being subject to the jurisdiction of the Bankruptcy Court. While operating as debtors in possession under Chapter 11, PG&E Corporation and the Utility may sell or otherwise dispose of or liquidate assets or settle liabilities, subject to the approval of the Bankruptcy Court or as otherwise permitted in the ordinary course of business and subject to restrictions in PG&E Corporation's and the Utility's DIP Credit Agreement (see Note 4 and Note 15 below) and applicable orders of the Bankruptcy Court, for amounts other than those reflected in the accompanying Consolidated Financial Statements. Any such actions occurring during the Chapter 11 Cases confirmed by the Bankruptcy Court could materially impact the amounts and classifications of assets and liabilities reported in PG&E Corporation's and the Utility's Consolidated Financial Statements.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Loss Contingencies

A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can reasonably be estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation’s and the Utility’s provision for loss and expense excludes anticipated legal costs, which are expensed as incurred.

Regulation and Regulated Operations

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover “revenue requirements” that have been authorized by the CPUC or the FERC based on the Utility’s cost of providing service. The Utility’s ability to recover a significant portion of its authorized revenue requirements through rates is generally independent, or “decoupled,” from the volume of the Utility’s electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

The Utility also records a regulatory balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund. In addition, the Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. These differences have no impact on net income. See “Revenue Recognition” below.

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable. To the extent that portions of the Utility’s operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

Revenue Recognition

Revenue from Contracts with Customers

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements. Revenues can vary significantly from period to period because of seasonality, weather, and customer usage patterns.

The FERC authorizes the Utility's revenue requirements in periodic TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled, net of a reserve for revenues subject to refund.

Regulatory Balancing Account Revenue

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, electric and natural gas operating revenue is recognized ratably over the year.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas, and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred. The Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. As a result, these differences have no impact on net income.

The following table presents the Utility's revenues disaggregated by type of customer:

(in millions)	Year Ended December 31, 2018
Electric	
Revenue from contracts with customers	
Residential	$ 5,051
Commercial	4,908
Industrial	1,532
Agricultural	1,234
Public street and highway lighting	72
Other (1)	(720)
Total revenue from contracts with customers - electric	12,077

Regulatory balancing accounts (2)		636
Total electric operating revenue	**$**	**12,713**
Natural gas		
Revenue from contracts with customers		
Residential	$	2,042
Commercial		537
Transportation service only		1,151
Other (1)		75
Total revenue from contracts with customers - gas		3,805
Regulatory balancing accounts (2)		242
Total natural gas operating revenue		**4,047**
Total operating revenues	**$**	**16,760**

(1) This activity is primarily related to the change in unbilled revenue and amounts subject to refund, partially offset by other miscellaneous revenue items.

(2) These amounts represent revenues authorized to be billed or refunded to customers.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

Allowance for Doubtful Accounts Receivable

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectable customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

Inventories

Inventories are carried at weighted-average cost and include natural gas stored underground as well as materials and supplies. Natural gas stored underground is recorded to inventory when injected and then expensed as the gas is withdrawn for distribution to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and expensed or capitalized to plant, as appropriate, when consumed or installed.

Emission Allowances

The Utility purchases GHG emission allowances to satisfy its compliance obligations. Associated costs are recorded as inventory and included in current assets – other and other noncurrent assets – other on the Consolidated Balance Sheets. Costs are carried at weighted-average and are recoverable through rates.

Property, Plant, and Equipment

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value. Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

(in millions, except estimated useful lives)	Estimated Useful Lives (years)	Balance at December 31, 2018	2017
Electricity generating facilities (1)	5 to 120	$ 13,047	$ 11,843
Electricity distribution facilities	15 to 65	32,926	31,110
Electricity transmission facilities	15 to 75	13,177	12,180
Natural gas distribution facilities	20 to 60	13,296	12,312
Natural gas transmission and storage facilities	5 to 62	8,260	7,329
Construction work in progress		2,564	2,471
Total property, plant, and equipment		**83,270**	**77,245**
Accumulated depreciation		(24,713)	(23,456)
Net property, plant, and equipment		**$ 58,557**	**$ 53,789**

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 14 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.82% in 2018, 3.83% in 2017, and 3.73% in 2016. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $53 million and $129 million during 2018, $38 million and $89 million during 2017, and $51 million and $112 million during 2016.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2018 and 2017, including nuclear decommissioning obligations:

(in millions)	2018	2017
ARO liability at beginning of year	$ 4,899	$ 4,684
Revision in estimated cash flows	993	128
Accretion	211	207
Liabilities settled	(109)	(120)
ARO liability at end of year	**$ 5,994**	**$ 4,899**

The Utility has not recorded a liability related to certain AROs for assets that are expected to operate in perpetuity. As the Utility cannot estimate a settlement date or range of potential settlement dates for these assets, reasonable estimates of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities associated with substations, photovoltaic facilities, and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration of land to the conditions under certain agreements.

Nuclear Decommissioning Obligation

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. In December 2018, the Utility submitted its updated decommissioning cost estimate to the CPUC and correspondingly increased its ARO liabilities by $1.1 billion. The adjustment was a result of increased estimated costs based on a site-specific decommissioning analysis. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

The total nuclear decommissioning obligation accrued was $4.7 billion and $3.5 billion at December 31, 2018 and 2017, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $10.6 billion and $7.0 billion at December 31, 2018 and 2017, respectively.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. See "Enforcement and Litigation Matters" in Note 14 below.

Nuclear Decommissioning Trusts

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its debt investments held in the nuclear decommissioning trusts as available-for-sale. Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2018, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2018, it did not consolidate any of them.

Other Accounting Policies

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies and Commitments" in Notes 13 and 14 herein.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2018 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
Beginning balance	$ (25)	$ 17	$ (8)
Other comprehensive income before reclassifications:			
Unrecognized net actuarial loss (net of taxes of $41 and $9, respectively)	(104)	(23)	(127)
Regulatory account transfer (net of taxes of $41 and $9, respectively)	107	23	130
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $2 and $4, respectively) (1)	(4)	10	6

Amortization of net actuarial loss (net of taxes of $2 and $1, respectively) (1)	3	(4)	(1)
Regulatory account transfer (net of taxes of $1 and $3, respectively) (1)	2	(6)	(4)
Net current period other comprehensive loss	**4**	**—**	**4**
Ending balance	**$ (21)**	**$ 17**	**$ (4)**

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2017 consisted of the following:

(in millions, net of income tax)	**Pension Benefits**	**Other Benefits**	**Total**
Beginning balance	**$ (25)**	**$ 16**	**$ (9)**
Other comprehensive income before reclassifications:			
Unrecognized prior service cost (net of taxes of $4 and $0, respectively)	(6)	—	(6)
Unrecognized net actuarial loss (net of taxes of $229 and $97, respectively)	333	141	474
Regulatory account transfer (net of taxes of $225 and $97, respectively)	(327)	(141)	(468)
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $3 and $6, respectively) (1)	(4)	9	5
Amortization of net actuarial loss (net of taxes of $9 and $2, respectively) (1)	13	2	15
Regulatory account transfer (net of taxes of $6 and $8, respectively) (1)	(9)	(10)	(19)
Net current period other comprehensive loss	**—**	**1**	**1**
Ending balance	**$ (25)**	**$ 17**	**$ (8)**

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

Recently Adopted Accounting Standards

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-9, *Revenue from Contracts with Customers (Topic 606)*, which amends the previous revenue recognition guidance. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability across entities, industries, jurisdictions, and capital markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. PG&E Corporation and the Utility applied the requirements using the modified retrospective method when the ASU became effective on January 1, 2018. The adoption of this guidance did not have a material impact on the Consolidated Financial Statements as of the adoption date or for the year ended December 31, 2018. A majority of the Utility's revenue from contracts with customers continues to be recognized on a monthly basis based on applicable tariffs and customers' monthly consumption. Such revenue is recognized using the invoice practical expedient which allows an entity to recognize revenue in the amount that directly corresponds to the value transferred to the customer. See "Revenue Recognition" above.

Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows – Restricted Cash (Topic 230)*, which amends the existing guidance relating to the disclosure of restricted cash and restricted cash equivalents on the statement of cash flows. Amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning and end of period total amounts shown on the statement of cash flows. Previously, changes in restricted cash were reported within cash flows from investing activities. PG&E Corporation and the Utility applied the requirements on a retrospective basis when the ASU became effective on January 1, 2018. The adoption of this guidance did not have a material impact on the Consolidated Financial Statements as of the adoption date or for the year ended December 31, 2018.

The retrospective adjustments to the Consolidated Statements of Cash Flows for PG&E Corporation and the Utility resulted in an increase to Net cash used in investing activities of $227 million, an increase to Cash, cash equivalents and restricted cash at January 1 by $234 million, and an increase to Cash, cash equivalents and restricted cash at December 31 by $7 million for the year ended December 31, 2016.

Presentation of Net Periodic Pension and Post-Retirement Benefit Costs

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715)*, which amends the guidance relating to the presentation of net periodic pension cost and net periodic other post-retirement benefit costs. PG&E Corporation and the Utility applied the requirements when the ASU became effective on January 1, 2018.

On a retrospective basis, the amendment requires an employer to separate the service cost component from the other components of net benefit cost and provides explicit guidance on how to present the service cost component and other components in the income statement. As a result, the Consolidated Statements of Income for PG&E Corporation and the Utility were restated. This change resulted in increases to Operating and maintenance expenses and Other income, net, of $51 million and $54 million for PG&E Corporation and the Utility, respectively, for the year ended December 31, 2017 and $97 million and $100 million for PG&E Corporation and the Utility, respectively, for the year ended December 31, 2016.

On a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The FERC has allowed and the Utility has made a one-time election to adopt the new FASB guidance for regulatory filing purposes. In January 2018, the CPUC approved modifications to the Utility's calculation for pension-related revenue requirements to allow for capitalization of only the service cost component determined by a plan's actuary. The capitalization of service costs only results in higher rate base and a reduction in the Utility's 2018 revenues. The changes in capitalization of retirement benefits did not have a material impact on PG&E Corporation's and the Utility's Consolidated Financial Statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*, which amends the guidance relating to the recognition, measurement, presentation, and disclosure of financial instruments. The amendments require equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. The majority of PG&E Corporation's and the Utility's investments are held in the nuclear decommissioning trusts and gains or losses are refundable or recoverable, respectively, from customers through rates, therefore gains and losses are deferred and recognized as regulatory assets or liabilities. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018 and did not have a material impact on the Consolidated Financial Statements and related disclosures.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

In February 2018, the FASB issued ASU No. 2018-02, *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. The amendments in this update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Act. When amounts are reclassified from accumulated other comprehensive income to the Consolidated Statement of Income, PG&E Corporation and the Utility recognize the related income tax expense at the tax rate in effect at that time. The ASU is effective for PG&E Corporation and the Utility on January 1, 2019, and early adoption is permitted. PG&E Corporation and the Utility early adopted this ASU on January 1, 2018, resulting in an immaterial reclassification.

Accounting Standards Issued But Not Yet Adopted

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which amends the guidance relating to the definition of a lease, recognition of ROU assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. Under the new standard, all lessees must recognize an ROU asset and lease liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU became effective for PG&E Corporation and the Utility on January 1, 2019.

PG&E Corporation and the Utility elected certain practical expedients and will carry forward historical conclusions related to (1) contracts that contain leases, (2) existing lease and easement classification, and (3) initial direct costs. Additionally, PG&E Corporation and the Utility do not intend to restate comparative periods upon adoption.

PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility will apply the requirements using the modified retrospective method. PG&E Corporation and the Utility expect this standard to increase ROU assets and liabilities by approximately $2.5 billion to $3.0 billion on the Consolidated Balance Sheets and will result in additional footnote disclosures, but do not expect the guidance will have a material impact on the Consolidated Statements of Income and Statements of Cash Flows. The majority of PG&E Corporation and the Utility's leases are power purchase agreements.

Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurements*, which amends the existing guidance relating to the disclosure requirements for fair value measurements. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Intangibles-Goodwill and Other

In August 2018, the FASB issued ASU No. 2018-15, *Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract*. This ASU will be effective for PG&E Corporation and the Utility on January 1, 2020 with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Balance at December 31, 2018	Balance at December 31, 2017	Recovery Period
Pension benefits [1]	$ 1,947	$ 1,954	Indefinitely
Environmental compliance costs	1,013	837	32 years
Utility retained generation [2]	274	319	8 years
Price risk management	90	65	10 years
Unamortized loss, net of gain, on reacquired debt	76	79	25 years
Catastrophic event memorandum account [3]	790	274	TBD years
Wildfire expense memorandum account [4]	94	—	TBD years
Fire hazard prevention memorandum account [5]	263	1	TBD years
Other	417	264	Various
Total long-term regulatory assets	**$ 4,964**	**$ 3,793**	

(1) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the Utility expects to continuously recover pension benefits.

(2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's 2001 proceeding under Chapter 11, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.

(3) Includes costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities. Recovery of CEMA costs are subject to CPUC review and approval.

(4) Includes specific incremental wildfire liability costs the CPUC approved for tracking in June 2018. Recovery of WEMA costs are subject to CPUC review and approval.

(5) Includes costs associated with the implementation of regulations and requirements adopted to protect the public from potential fire hazards associated with overhead power line facilities and nearby aerial communication facilities that have not been previously authorized in another proceeding. Recovery of FHPMA costs are subject to CPUC review and approval.

In general, regulatory assets represent the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recognized in accordance with GAAP. Additionally, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return on its regulatory assets for retained generation, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	**2018**	**2017**
Cost of removal obligations (1)	$ 5,981	$ 5,547
Deferred income taxes (2)	283	1,021
Recoveries in excess of AROs (3)	356	624
Public purpose programs (4)	674	590
Retirement Plan (5)	421	418
Other	824	479
Total long-term regulatory liabilities	**$ 8,539**	**$ 8,679**

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.

(2) Represents the net of amounts owed to customers for deferred taxes collected at higher rates before the Tax Act and amounts owed to the Utility for reversal of deferred taxes subject to flow-through treatment. (See Note 8 below.)

(3) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 10 below.)

(4) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

(5) Represents cumulative differences between incurred costs and amounts collected in rates for Post-Retirement Medical, Post-Retirement Life and Long Term Disability Plans.

Regulatory Balancing Accounts

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets. These differences do not have an impact on net income. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

	Receivable Balance at December 31,	
(in millions)	**2018**	**2017**
Electric distribution	$ 160	$ —
Electric transmission	128	139
Utility generation	79	—
Gas distribution and transmission	462	486
Energy procurement	168	71
Public purpose programs	111	103

Other	327	423
Total regulatory balancing accounts receivable	**$ 1,435**	**$ 1,222**

	Payable Balance at December 31,	
(in millions)	**2018**	**2017**
Electric distribution	$ —	$ 72
Electric transmission	134	120
Utility generation	—	14
Gas distribution and transmission	9	—
Energy procurement	59	149
Public purpose programs	587	452
Other	287	313
Total regulatory balancing accounts payable	**$ 1,076**	**$ 1,120**

The electric distribution and utility generation accounts track the collection of revenue requirements approved in the GRC. The electric transmission accounts track recovery of costs related to the transmission of electricity approved in the FERC TO rate cases. The gas distribution and transmission accounts track the collection of revenue requirements approved in the GRC and the GT&S rate case. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency.

NOTE 4: DEBT

Debtor In Possession ("DIP") Facilities

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into a Senior Secured Superpriority Debtor in Possession Credit, Guaranty and Security Agreement, dated as of February 1, 2019 (the “DIP Credit Agreement”), among the Utility, as borrower, PG&E Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent, Citibank, N.A., as collateral agent, and the lenders and issuing banks party thereto (together with such other financial institutions from time to time party thereto, the "DIP Lenders"). The DIP Credit Agreement provides for $5.5 billion in senior secured superpriority debtor in possession credit facilities in the form of (i) a revolving credit facility in an aggregate amount of $3.5 billion (the “DIP Revolving Facility”), including a $1.5 billion letter of credit subfacility, (ii) a term loan facility in an aggregate principal amount of $1.5 billion (the “DIP Initial Term Loan Facility”) and (iii) a delayed draw term loan facility in an aggregate principal amount of $500 million (the “DIP Delayed Draw Term Loan Facility”, together with the DIP Revolving Facility and the DIP Initial Term Loan Facility, the “DIP Facilities”), subject to the terms and conditions set forth therein.

On the Petition Date, PG&E Corporation and the Utility filed a motion seeking, among other things, interim and final approval of the DIP Facilities, which motion was granted on an interim basis by the Bankruptcy Court following a hearing on January 31, 2019. As a result of the Bankruptcy Court's interim approval of the DIP Facilities and the satisfaction of the other conditions thereof, the DIP Credit Agreement became effective on February 1, 2019 and a portion of the DIP Revolving Facility in the amount of $1.5 billion (including $750 million of the letter of credit subfacility) was made available to PG&E Corporation and the Utility. As of February 28, 2019, the remainder of the DIP Revolving Facility (including the remainder of the $1.5 billion letter of credit subfacility), the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility are unavailable for borrowing and will remain unavailable until and unless the Bankruptcy Court approves the availability thereof following a final hearing. PG&E Corporation and the Utility are unable to predict the date of the final hearing, but it is currently scheduled for March 13, 2019. There can be no assurances that the Bankruptcy Court will grant final approval of the DIP Facilities at the final hearing, or at all.

Borrowings under the DIP Facilities are senior secured obligations of the Utility, secured by substantially all of the Utility's assets and entitled to superpriority administrative expense claim status in the Utility's Chapter 11 Case. The Utility's obligations under the DIP Facilities are guaranteed by PG&E Corporation, and such guarantee is a senior secured obligation of PG&E Corporation, secured by substantially all of PG&E Corporation's assets and entitled to superpriority administrative expense claim status in PG&E Corporation's Chapter 11 Case.

The DIP Facilities mature on December 31, 2020, subject to the Utility's option to extend the maturity to December 31, 2021 if certain terms and conditions are satisfied, including the payment of an extension fee equal to 0.25% of the then-outstanding loans and available commitments. Borrowings under the DIP Facilities will bear interest based, at the Utility's election, on (1) LIBOR plus an applicable margin or (2) ABR plus an applicable margin. ABR will equal the highest of the following: (i) the administrative agent's announced base rate, (ii) 0.50% above the (x) federal funds effective rate or (y) the overnight federal funds rate, whichever is higher, (iii) one-month LIBOR plus 1.00% and (iv) zero. With respect to the DIP Revolving Facility, the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility, the applicable margin is 2.25% for LIBOR loans and 1.25% for ABR loans.

The Utility is also required to pay unused fees of (i) 0.375% per annum in respect of the average daily unutilized commitments under the DIP Revolving Facility and (ii) 1.125% per annum, which amount shall increase to 2.25% per annum after six months, in respect of the average daily unutilized commitments under the DIP Delayed Draw Term Loan Facility. The Utility must also pay (x) a fee equal to the applicable margin with respect to LIBOR loans under the DIP Revolving Facility on the aggregate drawable amount of all outstanding letters of credit under the DIP Revolving Facility and (y) a fronting fee to the relevant issuing DIP Lender equal to 0.125% per annum of the aggregate drawable amount of outstanding letters of credit issued by such issuing DIP Lender.

The DIP Credit Agreement includes usual and customary covenants for debtor in possession loan agreements of this type, including covenants limiting PG&E Corporation's and the Utility's ability to, among other things, incur additional indebtedness, create liens on assets, make investments, loans or advances, engage in mergers, consolidations, sales of assets and acquisitions, pay dividends and distributions and make payments in respect of junior or pre-petition indebtedness, in each case subject to customary exceptions for debtor in possession loan agreements of this type.

The DIP Credit Agreement also includes customary and usual representations and warranties and affirmative covenants, including an obligation to deliver 13-week cash flow forecasts and reports showing variances from such forecasts, in each case on a rolling 4-week basis. PG&E Corporation's and the Utility's obligations under the DIP Credit Agreement may be accelerated following certain events of default, including payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to post-petition or unstayed indebtedness of PG&E Corporation and the Utility and their subsidiaries in excess of $200 million, certain events under ERISA, unstayed judgments in respect of post-petition obligations involving an aggregate liability in excess of $200 million, change of control, specified governmental actions having a material adverse effect or condemnation or damage to a material portion of the collateral. Certain bankruptcy-related events are also events of default, including, but not limited to, the dismissal by the Bankruptcy Court of any of the Chapter 11 Cases, the conversion of any of the Chapter 11 Cases to a case under chapter 7 of the Bankruptcy Code, the appointment of a trustee pursuant to Chapter 11, any order authorizing the DIP Facilities being stayed, vacated, reversed or amended in a manner adverse to the DIP Lenders, the final order approving the DIP Facilities failing to have been entered by April 15, 2019, and certain other events related to the impairment of the DIP Lenders' rights or liens granted under the DIP Credit Agreement.

The proceeds of the borrowings under the DIP Facilities will be used for working capital and general corporate purposes and to pay fees, costs and expenses incurred in connection with the transactions contemplated by the DIP Credit Agreement and professional and other fees and costs of administration incurred in connection with the Chapter 11 Cases.

Long-Term Debt

Debt Obligations Previously Classified as Long Term

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

		December 31,	
(in millions)		**2018**	**2017**
PG&E Corporation			
Term Loan:			
Stated Maturity	Interest Rates		
2020	variable rate (2)	350	350
Less: Current Portion (1)		(350)	—
Total PG&E Corporation long-term debt		—	350
Utility			
Senior notes:			
Stated Maturity	Interest Rates		
2018	8.25%	—	400
2020	3.50%	800	800
2021	3.25% to 4.25%	550	550
2022	2.45%	400	400
2023 through 2046	2.95% to 6.35%	15,775	14,975
Unamortized discount, net of premium and debt issuance costs		(178)	(185)

Less: current portion (1)		(17,347)	(400)
Total senior notes, net of current portion		—	16,540
Pollution control bonds:			
Stated Maturity	Interest Rates		
Series 2008 G, due 2018	1.05%	—	45
Series 2008 F and 2010 E, due 2026 (3)	1.75%	100	100
Series 2009 A-B, due 2026 (4)	variable rate (5)	149	149
Series 1996 C, E, F, 1997 B due 2026 (4)	variable rate (6)	614	614
Less: current portion (1)		(863)	(45)
Total pollution control bonds		**—**	**863**
Total Utility long-term debt, net of current portion		**—**	**17,403**
Total consolidated long-term debt, net of current portion		**$ —**	**$ 17,753**

(1) On January 29, 2019, PG&E Corporation and the Utility commenced reorganization under Chapter 11 of the U.S. Bankruptcy Code. The commencement of the Chapter 11 Cases constituted an event of default or termination event under the above-referenced debt of PG&E Corporation and the Utility. With the exception of Pollution Control Bonds series 2008F and 2010E, where a trustee notice is required to trigger acceleration, the commencement of the Chapter 11 Cases caused an automatic and immediate acceleration of such debt, and the possibility of cure is uncertain. Therefore, all long-term debt is classified as current as of December 31, 2018.

(2) At December 31, 2018, the interest rate on the Term Loan was 3.66%.

(3) Pollution Control Bonds series 2008F and 2010E were remarketed and issued in June 2017. Although the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 31, 2022.

(4) Each series of these bonds is supported by a separate direct-pay letter of credit. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent. Series 2009 A-B bonds have a maturity date of June 5, 2019. In December 2015, Series 1996 C, E, F, 1997 B bonds the letters of credit were extended to December 1, 2020. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(5) At December 31, 2018, the interest rate on these bonds was 2.08%.

(6) At December 31, 2018, the interest rate on these bonds ranged from 2.05% to 2.15%.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sales agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. Except for components that may have been abandoned in place or disposed of as scrap or that are permanently non-operational, the Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

Repayment Schedule

PG&E Corporation's and the Utility's long-term debt is in default, and the Accelerated Direct Financial Obligations became immediately due and payable upon the commencement of the Chapter 11 Cases. PG&E Corporation's and the Utility's combined stated long-term debt principal repayment amounts at December 31, 2018 are reflected in the table below:

(in millions, except interest rates)	2019	2020	2021	2022	2023	Thereafter	Total
PG&E Corporation							
Variable interest rate as of December 31, 2018	—%	3.51%	—%	—%	—%	—%	3.51%
Variable rate obligations	$ —	$ 350	$ —	$ —	$ —	$ —	$ 350
Utility							
Average fixed interest rate	—%	3.50%	3.80%	2.31%	3.83%	4.74%	4.52%
Fixed rate obligations	$ —	$ 800	$ 550	$ 500	$ 1,175	$ 14,600	$ 17,625
Variable interest rate as of December 31, 2018	1.78 %	1.59%	—%	—%	—%	—%	1.63%
Variable rate obligations (1)	$ 149	$ 614	$ —	$ —	$ —	$ —	$ 763
Total consolidated debt	**$ 149**	**$ 1,764**	**$ 550**	**$ 500**	**$ 1,175**	**$ 14,600**	**$ 18,738**

(1) The bonds due in 2026 are backed by separate letters of credit that expire June 5, 2019, or December 1, 2020.

Short-term Borrowings

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings and availability under their revolving credit facilities and commercial paper programs at December 31, 2018:

(in millions)	Termination Date	Credit Facility Limit	Borrowings Against Revolver	Commercial Paper Outstanding	Facility Availability
PG&E Corporation	April 2022	$ 300 (1)	$ 300	$ —	$ —
Utility	April 2022	$ 3,000 (2)	$ 2,965 (3)	$ —	$ 35
Total revolving credit facilities		**$ 3,300**	**$ 3,265**	**$ —**	**$ 35**

(1) Includes a $50 million lender commitment to the letter of credit sublimits and a $100 million commitment for swingline loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.

(2) Includes a $500 million lender commitment to the letter of credit sublimits and a $75 million commitment for swingline loans.

(3) Includes $80 million of letters of credit.

For the year ended December 31, 2018, PG&E Corporation's average outstanding commercial paper balance was $29 million and the maximum outstanding balance during the year was $137 million. For the year ended December 31, 2018, the Utility's average outstanding commercial paper balance was $9 million and the maximum outstanding balance during the year was $205 million. As of December 31, 2018, PG&E Corporation and the Utility each had no commercial paper borrowings outstanding. PG&E Corporation and the Utility do not expect to be able to access the commercial paper market for the duration of the Chapter 11 Cases.

The commencement of the Chapter 11 Cases constituted an event of default or termination event, and caused an automatic and immediate acceleration of the Accelerated Direct Financial Obligations. However, any efforts to enforce such payment obligations are automatically stayed as of the Petition Date, and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The material Accelerated Direct Financial Obligations include the outstanding senior notes, agreements in respect of certain series of pollution control bonds, and PG&E Corporation's term loan facility, as well as short-term borrowings under PG&E Corporation's and the Utility's revolving credit facilities and the Utility's term loan facility. See Note 15 below for more information.

Revolving Credit Facilities

In May 2017, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022. As previously disclosed, PG&E Corporation's and the Utility's revolving credit facilities have been subject to an automatic and immediate acceleration as a result of the Chapter 11 Cases. Prior to the Chapter 11 Cases, proceeds from the revolving credit facilities were used for working capital, the repayment of commercial paper, and other corporate purposes.

Borrowings under each credit agreement (other than swingline loans) previously bore interest based on the borrower’s credit rating and on each borrower’s election of either (1) LIBOR plus an applicable margin or (2) the base rate plus an applicable margin. The base rate equaled the higher of the following: the administrative agent’s announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. The borrower’s credit rating at the time of borrowing determined the applicable rate within the following ranges. The applicable margin for LIBOR loans ranged between 0.9% and 1.475% under PG&E Corporation’s credit agreement and between 0.8% and 1.275% under the Utility’s credit agreement. The applicable margin for base rate loans ranged between 0% and 0.475% under PG&E Corporation’s credit agreement and between 0% and 0.275% under the Utility’s credit agreement. In addition, the facility fee under PG&E Corporation’s and the Utility’s credit agreements ranged between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

PG&E Corporation’s and the Utility’s revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the respective revolving credit facilities required that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation’s revolving credit facility agreement also required that PG&E Corporation own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

Commercial Paper Programs

The borrowings from PG&E Corporation’s and the Utility’s commercial paper programs were used primarily to fund temporary financing needs. PG&E Corporation and the Utility could issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treated the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper had maturities up to 365 days and ranked equally with PG&E Corporation’s and the Utility’s other unsubordinated and unsecured indebtedness. Commercial paper notes were sold at an interest rate dictated by the market at the time of issuance. For 2018, the average yield on outstanding PG&E Corporation and Utility commercial paper was 1.85% and 1.91%, respectively.

Other Short-term Borrowings

In February 2018, the Utility's $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. In February 2018, the Utility entered into a $250 million floating rate unsecured term loan. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper. As a result of the Chapter 11 Cases, repayment of this loan, which was scheduled to mature on February 22, 2019, has been stayed.

As of December 31, 2018, PG&E Corporation and the Utility each had no commercial paper borrowings. PG&E Corporation and the Utility do not expect to be able to access the commercial paper market for the duration of the Chapter 11 Cases.

In November 2018, the Utility's $500 million floating rate unsecured term loan, issued in November 2017, matured and was repaid.

NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 520,338,710 shares of common stock outstanding at December 31, 2018. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2018.

During 2018, PG&E Corporation sold no shares of common stock under the February 2017 EDA.

In addition, during 2018, PG&E Corporation sold 5.6 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $199 million. Beginning January 1, 2019 PG&E Corporation changed its default matching contributions under its 401(k) plan from PG&E common stock to cash.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with wildfires. See Wildfire-related contingencies in Note 13 below.

Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio for each company, no amount of PG&E Corporation's retained earnings and $1.4 billion of the Utility's retained earnings was subject to this restriction at December 31, 2018. Additionally, the Utility's net assets, and therefore its ability to pay dividends, are restricted by the CPUC-authorized capital structure, which requires the Utility to maintain, on average, at least 52% equity. Based on the calculation of this ratio, none of the Utility's net assets were restricted at December 31, 2018. Additionally, as a result of this requirement, the Utility's ability to pay dividends in the future could be impacted by future potential liabilities. PG&E Corporation does not expect to pay any cash dividends for the foreseeable future.

Long-Term Incentive Plan

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including stock options, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 15,150,532 shares were available for future awards at December 31, 2018.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2018:

(in millions)	2018	2017	2016
Stock Options	$ 10	$ —	$ —
Restricted stock units	43	40	53
Performance shares	36	45	55
Total compensation expense (pre-tax)	**$ 89**	**$ 85**	**$ 108**
Total compensation expense (after-tax)	**$ 63**	**$ 50**	**$ 64**

Share-based compensation costs are generally not capitalized. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Stock Options

The exercise price of stock options granted under the 2014 LTIP and all other outstanding stock options is equal to the market price of PG&E Corporation's common stock on the date of grant. Stock options generally have a 10-year term and vest over four years of continuous service, subject to accelerated vesting in certain circumstances. As of December 31, 2018, $1.5 million of total unrecognized compensation costs related to nonvested stock options were expected to be recognized over a weighted average period of a year and a half for PG&E Corporation.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method was $10.24 per share in 2018. The significant assumptions used for shares granted in 2018 were:

	2018
Expected stock price volatility	23.00%
Expected annual dividend payment	3.10%
Risk-free interest rate	2.58%
Expected life (years)	6

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected dividend payment is the dividend yield at the date of grant. The risk-free interest rate for periods within the contractual term of the stock option is based on the U.S. Treasury rates in effect at the date of grant. The expected life of stock options is derived from historical data that estimates stock option exercises and employee departure behavior.

There was no tax benefit recognized from stock options for the year ended December 31, 2018.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2018:

	Number of Stock Option	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	—	N/A	N/A	N/A
Granted	1,571,876	$ 10.24	—	—
Vested	—	N/A	—	—
Forfeited	(49,739)	10.23	—	—
Outstanding at December 31	1,522,137	10.24	9.17	0
Expected to vest at December 31	1,430,407	$ 10.24	9.17	0
Exercisable at December 31	—	N/A	N/A	N/A

Restricted Stock Units

Restricted stock units granted after 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized ratably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2018, 2017, and 2016 was $40.92, $66.95, and $56.68, respectively. The total fair value of restricted stock units that vested during 2018, 2017, and 2016 was $41 million, $57 million, and $36 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2018, $43 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.79 years.

The following table summarizes restricted stock unit activity for 2018:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,379,235	$ 60.93
Granted	1,415,627	40.92
Vested	(691,408)	58.78
Forfeited	(123,642)	56.38
Nonvested at December 31	**1,979,812**	$ 47.66

Performance Shares

Performance shares generally will vest three years after the grant date. Upon vesting, performance shares are settled in shares of common stock based on either PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period or, for a small number of awards, an internal PG&E Corporation metric. Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled.

Compensation expense attributable to performance share is generally recognized ratably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value of PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2018, 2017, and 2016 was $36.92, $77.00, and $53.61 respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2018, $31 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.68 years.

The following table summarizes activity for performance shares in 2018:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,748,028	$ 63.40
Granted	763,392	36.92
Vested	(156,747)	56.24
Forfeited [1]	(916,582)	53.68
Nonvested at December 31	**1,438,091**	$ 56.32

[1] Includes performance shares that expired with zero value as performance targets were not met.

NOTE 6: PREFERRED STOCK

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $100 par value preferred stock, which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding.

The Utility has authorized 75 million shares of $25 par value preferred stock and 10 million shares of $100 par value preferred stock. At December 31, 2018 and December 31, 2017, the Utility's preferred stock outstanding included $145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $113 million of shares with interest rates between 4.36% and 5% that are redeemable between $25.75 and $27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

At December 31, 2018, annual dividends on the Utility's nonredeemable preferred stock ranged from $1.25 to $1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2018, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid no dividends on preferred stock in 2018 (See "Dividends" in Note 5, above). The Utility paid $14 million of dividends on preferred stock in 2017 and 2016.

NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2018, 2017, and 2016.

	Year Ended December 31,		
(in millions, except per share amounts)	**2018**	**2017**	**2016**
Income available for common shareholders	$ (6,851)	$ 1,646	$ 1,393
Weighted average common shares outstanding, basic	517	512	499
Add incremental shares from assumed conversions:			
Employee share-based compensation	—	1	2
Weighted average common share outstanding, diluted	517	513	501
Total earnings per common share, diluted	**$ (13.25)**	**$ 3.21**	**$ 2.78**

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

NOTE 8: INCOME TAXES

PG&E Corporation and the Utility use the asset and liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance in the financial statements represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

	PG&E Corporation			**Utility**		
	Year Ended December 31,					
(in millions)	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Current:						
Federal	$ (5)	$ (10)	$ (105)	$ 5	$ 61	$ (105)
State	(8)	48	(70)	(7)	50	(66)
Deferred:						
Federal	(2,264)	481	218	(2,278)	326	229
State	(1,009)	6	16	(1,009)	4	16
Tax credits	(6)	(14)	(4)	(6)	(14)	(4)
Income tax provision (benefit)	**$ (3,292)**	**$ 511**	**$ 55**	**$ (3,295)**	**$ 427**	**$ 70**

The following table describes net deferred income tax liabilities:

	PG&E Corporation		**Utility**	
	Year Ended December 31,			
(in millions)	**2018**	**2017**	**2018**	**2017**
Deferred income tax assets:				
Tax carryforwards	$ 740	$ 830	$ 650	$ 736
Compensation	173	274	121	205
Income tax regulatory liability(1)	79	286	79	286
Wildfire-related Reserve (2)	3,433	34	3,433	34
Other (3)	87	151	93	160
Total deferred income tax assets	**$ 4,512**	**$ 1,575**	**$ 4,376**	**$ 1,421**
Deferred income tax liabilities:				
Property related basis differences	7,672	7,269	7,660	7,256
Other (4)	121	128	121	128
Total deferred income tax liabilities	**$ 7,793**	**$ 7,397**	**$ 7,781**	**$ 7,384**
Total net deferred income tax liabilities	**$ 3,281**	**$ 5,822**	**$ 3,405**	**$ 5,963**

(1) Represents the tax gross up portion of the deferred income tax for the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized for tax, including the impact of changes in net deferred taxes associated with a lower federal income tax rate as a result of the Tax Act. (For more information see Note 3 above).

(2) Amounts primarily relate to wildfire-related claims, net of estimated insurance recoveries, and legal and other costs related to the 2018 Camp fire, 2017 Northern California wildfires, and the 2015 Butte fire.

(3) Amounts include benefits, environmental reserve, and customer advances for construction.

(4) Amounts primarily relate to regulatory balancing accounts.

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2018	2017	2016	2018	2017	2016
Federal statutory income tax rate	21.0 %	35.0 %	35.0 %	21.0 %	35.0 %	35.0 %
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	7.9	1.5	(2.5)	7.9	1.6	(2.2)
Effect of regulatory treatment of fixed asset differences (2)	3.6	(16.5)	(23.7)	3.6	(16.8)	(23.4)
Tax credits	0.1	(1.1)	(0.8)	0.1	(1.1)	(0.8)
Benefit of loss carryback	—	—	(1.1)	—	—	(1.1)
Compensation Related (3)	(0.2)	(1.0)	(0.1)	(0.1)	(0.9)	(0.2)
Tax Reform Adjustment (4)	0.1	6.8	—	0.1	3.0	—
Other, net (5)	—	(1.1)	(3.0)	—	(0.7)	(2.5)
Effective tax rate	**32.5%**	**23.6%**	**3.8%**	**32.6%**	**20.1%**	**4.8%**

(1) Includes the effect of state flow-through ratemaking treatment. In 2016, amounts reflect a settlement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision (impacting the twelve months ended December 31, 2017), the 2017 GRC decision (impacting the twelve months ended December 31, 2018), and by the 2015 GT&S decision which impacted all periods presented. All amounts are impacted by the level of income before income taxes. The 2014 GRC, 2017 GRC, and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 2018, the amounts also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December 2017.

(3) Primarily represents adjustments to compensation as a result of the enactment of the Tax Act.

(4) Represents adjustments to deferred tax balances under Staff Accounting Bulletin No. 118 reflecting the tax rate reduction required by the Tax Act.

(5) These amounts primarily represents the impact of tax audit settlements.

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
(in millions)	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Balance at beginning of year	$ 349	$ 388	$ 468	$ 349	$ 382	$ 462
Reductions for tax position taken during a prior year	(27)	(71)	(77)	(27)	(71)	(77)
Additions for tax position taken during the current year	55	48	56	55	48	56
Settlements	—	(14)	(59)	—	(8)	(59)
Expiration of statute	—	(3)	—	—	(3)	—
Balance at end of year	**$ 377**	**$ 349**	**$ 388**	**$ 377**	**$ 349**	**$ 382**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2018 for PG&E Corporation and the Utility was $5 million.

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2018, it is reasonably possible that unrecognized tax benefits will decrease by approximately $50 million within the next 12 months.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2018, 2017, and 2016, these amounts were immaterial.

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35% to 21% beginning on January 1, 2018 and eliminated bonus depreciation for utilities. At December 31, 2017, PG&E Corporation and the Utility recorded estimated provisional amounts to reflect the effect of the Tax Act in accordance with Staff Accounting Bulletin No. 118. In 2018, PG&E Corporation and the Utility recorded an approximately $13 million tax benefit to adjust the amount recorded in 2017 for the Tax Act upon obtaining, preparing, and analyzing additional information regarding facts and circumstances that existed as of the enactment date that, if known, would have affected the income tax effects initially reported as provisional amounts.

Although the accounting under ASC 740 to reflect the Tax Act is now complete, the Treasury is still issuing interpretive guidance on various aspects of the Tax Act. If future guidance requires a change in the recorded tax amounts, any necessary change will be reflected in the period such guidance is issued.

In addition, the Utility filed the estimated revenue impact of the Tax Act with the CPUC and FERC in March and May of 2018, respectively. As of December 31, 2018, the Utility still has not received final regulatory decisions. Depending on the final regulatory outcome, an adjustment may need to be made in the period the final decisions are issued.

Tax settlements

PG&E Corporation's tax returns have been accepted through 2015 except for a few matters, the most significant of which relate to deductible repair costs for gas transmission and distribution lines of business and tax deductions claimed for regulatory fines and fees assessed as part of the Penalty Decision issued in 2015 for the San Bruno natural gas explosion in September of 2010. In February 2017, the Joint Committee of Taxation approved PG&E Corporation's settlement with the IRS related to deductible electric transmission and distribution repairs for the 2011 and 2012 tax years. The agreement provided that the methodology used in determining the deductible amount should be followed for all subsequent periods, absent any material change in facts. In November 2017, PG&E Corporation reached an agreement with the IRS on deductible generation repairs for the 2013 and 2014 tax years.

Tax years after 2007 remain subject to examination by the state of California.

Carryforwards

The following table describes PG&E Corporation's operating loss and tax credit carryforward balances:

(in millions)	December 31, 2018	Expiration Year
Federal:		
Net operating loss carryforward	$ 3,880	2031 - 2036
Tax credit carryforward	118	2029 - 2037
Charitable contribution loss carryforward	10	2020
State:		
Net operating loss carryforward	$ 58	2038
Tax credit carryforward	79	Various
Charitable contribution loss carryforward	10	2020 - 2021

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating losses, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2018 for these tax attributes.

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. PG&E Corporation does not believe that the Chapter 11 Cases resulted in loss of or limitation on the utilization of any of the tax carryforwards. PG&E Corporation will continue to monitor the status during the pendency of the Chapter 11 Cases.

NOTE 9: DERIVATIVES

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Derivatives are presented in the Utility's Consolidated Balance Sheets recorded at fair value and on a net basis in accordance with master netting arrangements for each counter-party. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Consolidated Balance Sheets at fair value.

Volume of Derivative Activity

At December 31, 2018 and 2017, respectively, the volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume	
Underlying Product	**Instruments**	**2018**	**2017**
Natural Gas (1) (MMBtus (2))	Forwards and Swaps	177,750,349	228,768,745
	Options	13,735,405	60,736,806
Electricity (Megawatt-hours)	Forwards and Swaps	3,833,490	2,872,013
	Congestion Revenue Rights (3)	340,783,089	312,272,177

(1) Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

(2) Million British Thermal Units.

(3) CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

Presentation of Derivative Instruments in the Financial Statements

At December 31, 2018, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 44	$ (1)	$ 89	$ 132
Other noncurrent assets – other	165	—	—	165
Current liabilities – other	(29)	1	7	(21)
Noncurrent liabilities – other	(90)	—	2	(88)

Total commodity risk	**$ 90**	**$ —**	**$ 98**	**$ 188**

At December 31, 2017, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 30	$ (3)	$ 10	$ 37
Other noncurrent assets – other	103	(1)	—	102
Current liabilities – other	(47)	3	13	(31)
Noncurrent liabilities – other	(66)	1	8	(57)
Total commodity risk	**$ 20**	**$ —**	**$ 31**	**$ 51**

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives instruments, including certain power purchase agreements, contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies, also known as a credit-risk-related contingent feature. In January 2019, multiple credit rating agencies downgraded the Utility below investment grade, resulting in the Utility posting $6.2 million to fully collateralize its net liability derivative positions.

NOTE 10: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets and price risk management instruments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

	Fair Value Measurements				
	At December 31, 2018				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					

Short-term investments	$ 1,593	$ —	$ —	$ —	**$ 1,593**
Nuclear decommissioning trusts					
Short-term investments	29	—	—	—	**29**
Global equity securities	1,793	—	—	—	**1,793**
Fixed-income securities	661	639	—	—	**1,300**
Assets measured at NAV	—	—	—	—	**16**
Total nuclear decommissioning trusts (2)	**2,483**	**639**	**—**	**—**	**3,138**
Price risk management instruments (Note 9)					
Electricity	—	5	203	51	**259**
Gas	—	1	—	37	**38**
Total price risk management instruments	**—**	**6**	**203**	**88**	**297**
Rabbi trusts					
Fixed-income securities	—	93	—	—	**93**
Life insurance contracts	—	67	—	—	**67**
Total rabbi trusts	**—**	**160**	**—**	**—**	**160**
Long-term disability trust					
Short-term investments	7	—	—	—	**7**
Assets measured at NAV	—	—	—	—	**155**
Total long-term disability trust	**7**	**—**	**—**	**—**	**162**
TOTAL ASSETS	**$ 4,083**	**$ 805**	**$ 203**	**$ 88**	**$ 5,350**
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	$ 4	$ 5	$ 108	$ (10)	**$ 107**
Gas	—	2	—	—	**2**
TOTAL LIABILITIES	**$ 4**	**$ 7**	**$ 108**	**$ (10)**	**$ 109**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Represents amount before deducting $408 million, primarily related to deferred taxes on appreciation of investment value.

	Fair Value Measurements				
	At December 31, 2017				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	$ 385	$ —	$ —	$ —	$ 385
Nuclear decommissioning trusts					
Short-term investments	23	—	—	—	23
Global equity securities	1,967	—	—	—	1,967
Fixed-income securities	733	562	—	—	1,295

Assets measured at NAV	—	—	—	—	18
Total nuclear decommissioning trusts (2)	**2,723**	**562**	**—**	**—**	**3,303**
Price risk management instruments (Note 9)					
Electricity	—	3	129	6	138
Gas	—	1	—	—	1
Total price risk management instruments	**—**	**4**	**129**	**6**	**139**
Rabbi trusts					
Fixed-income securities	—	72	—	—	72
Life insurance contracts	—	71	—	—	71
Total rabbi trusts	**—**	**143**	**—**	**—**	**143**
Long-term disability trust					
Short-term investments	8	—	—	—	8
Assets measured at NAV	—	—	—	—	167
Total long-term disability trust	**8**	**—**	**—**	**—**	**175**
TOTAL ASSETS	**$ 3,116**	**$ 709**	**$ 129**	**$ 6**	**$ 4,145**
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	10	15	87	(25)	87
Gas	—	1	—	—	1
TOTAL LIABILITIES	**$ 10**	**$ 16**	**$ 87**	**$ (25)**	**$ 88**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Represents amount before deducting $440 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the years ended December 31, 2018 and 2017.

Trust Assets

Assets Measured at Fair Value

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of fixed-income securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

Investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function, which reports to the Chief Financial Officer, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. See Note 9 above.

(in millions)	Fair Value at At December 31, 2018		Valuation Technique	Unobservable Input	
Fair Value Measurement	**Assets**	**Liabilities**			**Range (1)**
Congestion revenue rights	$ 203	$ 75	Market approach	CRR auction prices	$ (18.61) - 32.26
Power purchase agreements	$ —	$ 33	Discounted cash flow	Forward prices	$ 19.81 - 38.80

(1) Represents price per megawatt-hour

(in millions)	Fair Value at At December 31, 2017		Valuation Technique	Unobservable Input	
Fair Value Measurement	**Assets**	**Liabilities**			**Range (1)**
Congestion revenue rights	$ 129	$ 24	Market approach	CRR auction prices	$ (16.03) - 11.99
Power purchase agreements	$ —	$ 63	Discounted cash flow	Forward prices	$ 18.81 - 38.80

(1) Represents price per megawatt-hour

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2018 and 2017, respectively:

(in millions)	Price Risk Management Instruments 2018	2017
Asset (liability) balance as of January 1	**$ 42**	**$ 55**
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	53	(13)
Asset (liability) balance as of December 31	**$ 95**	**$ 42**

(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2018 and 2017, as they are short-term in nature or have interest rates that reset daily.

The carrying amount and fair value of PG&E Corporation's and the Utility's long-term debt instruments, excluding pollution control bonds, were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

	At December 31,			
	2018		2017	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 4)				
PG&E Corporation(1)	$ 350	$ 350	$ 350	$ 350
Utility	17,450	14,747	17,090	19,128

(1) On April 26, 2018, PG&E Corporation early redeemed its outstanding $350 million principal amount of 2.40% Senior Notes. Also, in April 2018, PG&E Corporation entered into a $350 million floating rate unsecured term loan. For more information, see Note 4.

Nuclear Decommissioning Trust Investments

The following table provides a summary of equity securities and available-for-sale debt securities:

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of December 31, 2018				
Nuclear decommissioning trusts				
Short-term investments	$ 29	$ —	$ —	$ 29
Global equity securities	568	1,246	(5)	1,809
Fixed-income securities	1,288	30	(18)	1,300
Total (1)	**$ 1,885**	**$ 1,276**	**$ (23)**	**$ 3,138**
As of December 31, 2017				
Nuclear decommissioning trusts				
Short-term investments	$ 23	$ —	$ —	$ 23
Global equity securities	524	1,463	(2)	1,985
Fixed-income securities	1,252	51	(8)	1,295
Total (1)	**$ 1,799**	**$ 1,514**	**$ (10)**	**$ 3,303**

(1) Represents amounts before deducting $408 million and $440 million at December 31, 2018 and 2017, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

(in millions)	As of December 31, 2018
Less than 1 year	$ 60
1–5 years	391
5–10 years	341
More than 10 years	508
Total maturities of fixed-income securities	**$ 1,300**

The following table provides a summary of activity for the fixed-income and equity securities:

(in millions)	2018	2017	2016
Proceeds from sales and maturities of nuclear decommissioning investments	$ 1,412	$ 1,291	$ 1,295
Gross realized gains on securities	54	53	18
Gross realized losses on securities	(24)	(11)	(26)

NOTE 11: EMPLOYEE BENEFIT PLANS

Pension Plan and Postretirement Benefits Other than Pensions ("PBOP")

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). Certain trusts underlying these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. On an annual basis, the Utility funds the pension plans up to the amount it is authorized to recover in rates, $327 million for both 2018 and 2017.

PG&E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utility use a fiscal year-end measurement date for all plans.

On February 27, 2019, PG&E Corporation and the Utility received approval from the Bankruptcy Court to maintain existing pension and other benefit plans during the pendency of the Chapter 11 Cases. (For more information see "Chapter 11 Proceedings" in Note 15 below.)

Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2018 and 2017:

Pension Plan

(in millions)	2018	2017
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 16,652**	**$ 14,729**
Actual return on plan assets	(923)	2,380
Company contributions	334	335
Benefits and expenses paid	(751)	(792)
Fair value of plan assets at end of year	**$ 15,312**	**$ 16,652**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 18,757**	**$ 17,305**
Service cost for benefits earned	514	472
Interest cost	687	714
Actuarial (gain) loss	(1,800)	1,048
Plan amendments	—	10
Benefits and expenses paid	(751)	(792)
Benefit obligation at end of year (1)	**$ 17,407**	**$ 18,757**
Funded Status:		
Current liability	$ (8)	$ (7)
Noncurrent liability	(2,087)	(2,098)
Net liability at end of year	**$ (2,095)**	**$ (2,105)**

(1) PG&E Corporation's accumulated benefit obligation was $15.8 billion and $16.8 billion at December 31, 2018 and 2017, respectively.

Postretirement Benefits Other than Pensions

(in millions)	2018	2017
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,420**	**$ 2,173**
Actual return on plan assets	(108)	298
Company contributions	31	33
Plan participant contribution	81	87
Benefits and expenses paid	(166)	(171)
Fair value of plan assets at end of year	**$ 2,258**	**$ 2,420**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,897**	**$ 1,877**
Service cost for benefits earned	66	59

Interest cost	69	77
Actuarial (gain) loss	(221)	(49)
Benefits and expenses paid	(150)	(157)
Federal subsidy on benefits paid	3	3
Plan participant contributions	81	87
Benefit obligation at end of year	**$ 1,745**	**$ 1,897**
Funded Status: (1)		
Noncurrent asset	$ 545	$ 553
Noncurrent liability	(32)	(30)
Net asset at end of year	**$ 513**	**$ 523**

(1) At December 31, 2018 and 2017, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Components of Net Periodic Benefit Cost

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan and cash balance plan. Both plans are included in "Pension Benefits" below. Post-retirement medical and life insurance plans are included in "Other Benefits" below.

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

Pension Plan

(in millions)	**2018**	**2017**	**2016**
Service cost for benefits earned (1)	$ 514	$ 472	$ 453
Interest cost	687	714	715
Expected return on plan assets	(1,021)	(770)	(828)
Amortization of prior service cost	(6)	(7)	8
Amortization of net actuarial loss	5	22	24
Net periodic benefit cost	**179**	**431**	**372**
Less: transfer to regulatory account (2)	157	(92)	(34)
Total expense recognized	**$ 336**	**$ 339**	**$ 338**

(1) A portion of service costs are capitalized pursuant to ASU 2017-07.

(2) The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

Postretirement Benefits Other than Pensions

(in millions)	2018	2017	2016
Service cost for benefits earned [1]	$ 66	$ 59	$ 52
Interest cost	69	77	76
Expected return on plan assets	(130)	(97)	(107)
Amortization of prior service cost	14	15	15
Amortization of net actuarial loss	(5)	4	4
Net periodic benefit cost	**$ 14**	**$ 58**	**$ 40**

[1] A portion of service costs are capitalized pursuant to ASU 2017-07.

Non-service costs are reflected in Other income, net on the Consolidated Statements of Income. Service costs are reflected in Operating and maintenance on the Consolidated Statements of Income.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Components of Accumulated Other Comprehensive Income

PG&E Corporation and the Utility record unrecognized prior service costs and unrecognized gains and losses related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax. In addition, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension benefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts that would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2019 are as follows:

(in millions)	Pension Plan	PBOP Plans
Unrecognized prior service cost	$ (6)	$ 14
Unrecognized net loss	3	(3)
Total	**$ (3)**	**$ 11**

There were no material differences between the estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation and the Utility.

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

	Pension Plan			PBOP Plans		
	December 31,			December 31,		
	2018	2017	2016	2018	2017	2016
Discount rate	4.35%	3.64%	4.11%	4.29 - 4.37%	3.60 - 3.67 %	4.05 - 4.19 %
Rate of future compensation increases	3.90%	3.90%	4.00%	—	—	—
Expected return on plan assets	6.00%	6.20%	5.30%	3.60 - 6.80%	3.30 - 7.10%	2.80 - 6.00%

The assumed health care cost trend rate as of December 31, 2018 was 6.5%, decreasing gradually to an ultimate trend rate in 2027 and beyond of approximately 4.5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on postretirement benefit obligation	$ 112	$ (113)
Effect on service and interest cost	9	(10)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.0% compares to a ten-year actual return of 10.0%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 1,101 Aa-grade non-callable bonds at December 31, 2018. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

Investment Policies and Strategies

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs in financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts' asset allocations are meant to manage volatility, reduce costs, and diversify its holdings. Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts' fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility, PG&E Corporation's and the Utility's trusts hold significant allocations in long maturity fixed-income investments. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, global REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Derivative instruments such as equity index futures are used to meet target equity exposure. Derivative instruments, such as equity index futures and U.S. treasury futures, are also used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are used to hedge a portion of the non U.S. dollar exposure of global equity investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

	Pension Plan			PBOP Plans		
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
Global equity securities	29 %	29 %	27 %	33 %	33 %	32 %
Absolute return	5 %	5 %	5 %	3 %	3 %	3 %
Real assets	8 %	8 %	10 %	6 %	6 %	7 %
Fixed-income securities	58 %	58 %	58 %	58 %	58 %	58 %
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2018 and 2017.

	Fair Value Measurements							
	At December 31,							
	2018				2017			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Pension Plan:								
Short-term investments	$ 333	$ 22	$ —	$ 355	$ 287	$ 424	$ —	$ 711
Global equity securities	1,145	—	—	1,145	1,292	—	—	1,292

Real assets	461	—	—	461	499	—	—	499
Fixed-income securities	1,897	5,216	8	7,121	1,916	5,520	4	7,440
Assets measured at NAV	—	—	—	6,202	—	—	—	6,818
Total	**$ 3,836**	**$ 5,238**	**$ 8**	**$ 15,284**	**$ 3,994**	**$ 5,944**	**$ 4**	**$ 16,760**
PBOP Plans:								
Short-term investments	$ 33	$ —	$ —	$ 33	$ 31	$ —	$ —	$ 31
Global equity securities	115	—	—	115	141	—	—	141
Real assets	50	—	—	50	55	—	—	55
Fixed-income securities	153	857	—	1,010	163	757	—	920
Assets measured at NAV	—	—	—	1,056	—	—	—	1,281
Total	**$ 351**	**$ 857**	**$ —**	**$ 2,264**	**$ 390**	**$ 757**	**$ —**	**$ 2,428**
Total plan assets at fair value				**$ 17,548**				**$ 19,188**

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net liabilities of $22 million and other net assets of $116 million at December 31, 2018 and 2017, respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

Short-Term Investments

Short-term investments consist primarily of commingled funds across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

Global Equity securities

The global equity category includes investments in common stock and equity-index futures. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets.

Real Assets

The real asset category includes portfolios of commodity futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets.

Fixed-Income securities

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

Investments in the trusts that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities, asset-backed securities, and private real estate funds. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

Transfers Between Levels

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No material transfers between levels occurred in the years ended December 31, 2018 and 2017.

Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for the pension plan that have been classified as Level 3 for the years ended December 31, 2018 and 2017:

(in millions)

For the year ended December 31, 2018		**Fixed-Income**
Balance at beginning of year	$	4
Actual return on plan assets:		
Relating to assets still held at the reporting date		(3)
Relating to assets sold during the period		—
Purchases, issuances, sales, and settlements:		
Purchases		6
Settlements		1
Balance at end of year	**$**	**8**

(in millions)

For the year ended December 31, 2017		**Fixed-Income**
Balance at beginning of year	$	5
Actual return on plan assets:		

Relating to assets still held at the reporting date		(1)
Relating to assets sold during the period		—
Purchases, issuances, sales, and settlements:		
Purchases		3
Settlements		(3)
Balance at end of year	**$**	**4**

There were no material transfers out of Level 3 in 2018 and 2017.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $334 million to the pension benefit plans and $31 million to the other benefit plans in 2018. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2018. The Utility's pension benefits met all the funding requirements under Employee Retirement Income Security Act. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $24 million to the pension plan and other postretirement benefit plans, respectively, for 2019.

Benefits Payments and Receipts

As of December 31, 2018, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	**Pension Plan**	**PBOP Plans**	**Federal Subsidy**
2019	778	88	(8)
2020	855	91	(9)
2021	891	94	(9)
2022	925	99	(3)
2023	957	102	(3)
Thereafter in the succeeding five years	5,136	507	(12)

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

Retirement Savings Plan

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were $105 million, $103 million, and $97 million in 2018, 2017, and 2016, respectively.

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

	Year Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 4	$ 8	$ 7
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 94	$ 65	$ 74
Utility employee benefit due to PG&E Corporation	76	73	91

At December 31, 2018 and 2017, the Utility had receivables of $33 million and $20 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $38 million and $22 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 13: WILDFIRE-RELATED CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to wildfires. A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can be reasonably estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the outcome of the following matters.

Wildfire-Related Claims

Wildfire-related claims on the Consolidated Financial Statements include amounts associated with the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire.

For the years ended December 31, 2018, 2017 and 2016, the Utility's Consolidated Income Statements include estimated losses offset by insurance recoveries as follows:

	Year Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
2015 Butte fire			
Third-Party Claims	$ —	$ 350	$ 750
Insurance recoveries	(7)	(350)	(625)
Total 2015 Butte fire	**(7)**	**—**	**125**
2017 Northern California wildfires			
Third-Party Claims	3,500	—	—
Insurance recoveries	(842)	—	—
Total 2017 Northern California wildfires	**2,658**	**—**	**—**
2018 Camp fire			
Third-Party Claims	10,500	—	—
Insurance recoveries	(1,380)	—	—
Total 2018 Camp fire	9,120	—	—
Total wildfire-related claims, net of insurance recoveries	**$ 11,771**	**$ —**	**$ 125**

In addition to the amounts shown in the table above, during the year ended December 31, 2018, the Utility incurred $245 million of legal and other costs related to the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire.

At December 31, 2018 and 2017, the Utility's Consolidated Balance Sheets include estimated liabilities as follows:

	Balance At	
(in millions)	**December 31, 2018**	**December 31, 2017**

2015 Butte fire	$	226	$	561
2017 Northern California wildfires		3,500		—
2018 Camp fire		10,500		—
Total wildfire-related claims	**$**	**14,226**	**$**	**561**

2018 Camp Fire Background

On November 8, 2018, a wildfire began near the city of Paradise, Butte County, California (the "2018 Camp fire"), which is located in the Utility's service territory. Cal Fire's Camp Fire Incident Information Website as of January 4, 2019, (the "Cal Fire website"), indicated that the 2018 Camp fire consumed 153,336 acres. On the Cal Fire website, Cal Fire reported 86 fatalities and the destruction of 13,972 residences, 528 commercial structures and 4,293 other buildings resulting from the 2018 Camp fire. On February 7, 2019, the Butte County Sheriff's Office reported that the number of fatalities resulting from the 2018 Camp fire had been reduced from 86 to 85.

Although the cause of the 2018 Camp fire is still under investigation, based on the information currently known to PG&E Corporation and the Utility and reported to the CPUC and other agencies, including the facts described below, PG&E Corporation and the Utility believe it is probable that the Utility's equipment will be determined to be an ignition point of the 2018 Camp fire.

The Utility submitted two Electric Incident Reports (the "EIRs") to the CPUC: one on November 8, 2018 and one on November 16, 2018. On December 11, 2018, the Utility publicly released a letter to the CPUC supplementing the EIRs (the "20-Day Electric Incident Report"), which stated:

- On Cal Fire's website, Cal Fire has identified coordinates for the 2018 Camp fire near Tower :27/222 on the Utility's Caribou-Palermo 115 kV Transmission Line and has identified the start time of the 2018 Camp fire as 6:33 a.m. on November 8, 2018.

- On November 8, 2018, at approximately 6:15 a.m., the Utility's Caribou-Palermo 115kV Transmission Line relayed and deenergized. At approximately 6:30 a.m. that day, a Utility employee observed fire in the vicinity of Tower :27/222, and this observation was reported to 911 by Utility employees. In the afternoon of November 8, the Utility observed damage on the line at Tower :27/222. Specifically, an aerial patrol identified that a suspension insulator supporting a transposition jumper had separated from an arm on Tower :27/222.

- On November 14, 2018, the Utility observed a broken C-hook attached to the separated suspension insulator that had connected the suspension insulator to a tower arm, along with wear at the connection point. In addition, the Utility observed a flash mark on Tower :27/222 near where the transposition jumper was suspended and damage to the transposition jumper and suspension insulator.

- In addition to the events on the Caribou-Palermo 115kV Transmission Line, on November 8, 2018, at approximately 6:45 a.m., the Utility's Big Bend 1101 12 kV Circuit experienced an outage. On November 9, 2018, a Utility employee on patrol arrived at the location of the pole with Line Recloser ("LR") 1704 on the Big Bend 1101 Circuit and observed that the pole and other equipment were on the ground with bullets and bullet holes at the break point of the pole and on the equipment. On November 12, 2018, a Utility employee was patrolling Concow Road north of LR 1704 when he observed wires down and damaged and downed poles at the intersection of Concow Road and Rim Road. At this location, the employee observed several snapped trees, with some on top of the downed wires.

The information contained in the EIRs and the 20-Day Electric Incident Report is factual and preliminary and does not reflect a determination of the causes of the 2018 Camp fire. These incidents remain under investigation by Cal Fire and the CPUC. With respect to the potential ignition point on the Utility's Big Bend 1101 12 kV Circuit, although Cal Fire has identified this location as a potential ignition point, based on the condition of the site, PG&E Corporation and the Utility have not been able to determine whether the Big Bend 1101 12 kV Circuit may be a probable ignition point for the 2018 Camp fire. Neither Cal Fire nor the CPUC has publicly issued any news releases or other determinations for the 2018 Camp fire. The timing and outcome of the investigations are uncertain. PG&E Corporation and the Utility are cooperating with Cal Fire and the CPUC.

Further, the CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating the fire. It is uncertain when the investigations will be complete and whether the SED will release any preliminary findings before its investigations are complete.

2017 Northern California Wildfires Background

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the "2017 Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the 2017 Northern California wildfires, there were 21 major fires that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The 2017 Northern California wildfires resulted in 44 fatalities.

Cal Fire has issued its determination on the causes of 19 of the 2017 Northern California wildfires, and alleged that all of these fires, with the exception of the Tubbs fire, involved the Utility's equipment. The remaining wildfires remain under Cal Fire's investigation, including the possible role of the Utility's power lines and other facilities.

During the second quarter of 2018, Cal Fire issued news releases announcing its determination on the causes of 16 of the 2017 Northern California wildfires (the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket and Atlas fires, located in Mendocino, Lake, Butte, Sonoma, Humboldt, Nevada and Napa counties). According to the Cal Fire news releases, the first four fires "were caused by trees coming into contact with power lines" and the remaining 12 fires "were caused by electric power and distribution lines, conductors and the failure of power poles." Cal Fire has not yet released its investigation reports related to the McCourtney, Lobo, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires and stated in its news releases that these investigations have been referred to the appropriate county District Attorney's offices for review "due to evidence of alleged violations of state law." The Butte County District Attorney's office has entered into a settlement agreement with the Utility, resolving the Honey, Cherokee and LaPorte fire allegations without criminal or civil charges. The timing and outcome for resolution of the remaining referrals are uncertain.

Also during the second quarter of 2018, Cal Fire released its investigation reports related to the Redwood, Cherokee, 37, Nuns and La Porte fires. Cal Fire did not refer these fires to District Attorney offices for investigation.

On October 9, 2018, Cal Fire issued a news release announcing the results of its investigation into the Cascade fire, located in Yuba County, concluding that the Cascade fire “was started by sagging power lines coming into contact during heavy winds” and that “the power line in question was owned by Pacific Gas and Electric Company.” On October 10, 2018, Cal Fire released its investigation report related to the Cascade fire.

On January 24, 2019, Cal Fire issued a news release and its investigation report into the cause of the Tubbs fire. Cal Fire has determined that the Tubbs fire was caused by a private electrical system adjacent to a residential structure.

Cal Fire has not publicly issued any news releases or other determinations for the Maacama, Pressley and Point wildfires. The timing and outcome of the Cal Fire investigation into these fires is uncertain.

Further, the SED is conducting investigations to assess the compliance of electric and communication companies’ facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. It is uncertain when the investigations will be complete and whether the SED will release any preliminary findings before its investigations are complete.

The Utility has submitted 23 electric incident reports to the CPUC associated with the 2017 Northern California wildfires where Cal Fire or the Utility has identified a site as potentially involving the Utility’s facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary and does not reflect a determination of the causes of the fires.

Third-Party Claims, Investigations and Other Proceedings Related to the 2018 Camp Fire and 2017 Northern California Wildfires

If the Utility’s facilities, such as its electric distribution and transmission lines, are determined to be the substantial cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest and attorneys’ fees without having been found negligent. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefited from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Further, California courts have determined that the doctrine of inverse condemnation is applicable regardless of whether the CPUC ultimately allows recovery by the utility for any such costs. The CPUC may decide not to authorize cost recovery even if a court decision were to determine that the Utility is liable as a result of the application of the doctrine of inverse condemnation. (See “Loss Recoveries-Regulatory Recovery” below for further information regarding potential cost recovery related to the wildfires, including in connection with SB 901.)

In addition to claims for property damage, business interruption, interest and attorneys’ fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, punitive damages and other damages under other theories of liability, including if the Utility were found to have been negligent.

Further, the Utility could be subject to material fines or penalties if the CPUC or any law enforcement agency brought an enforcement action, including a criminal proceeding, and determined that the Utility failed to comply with applicable laws and regulations.

As of January 28, 2019, PG&E Corporation and the Utility are aware of approximately 100 complaints on behalf of at least 4,200 plaintiffs related to the 2018 Camp fire, nine of which seek to be certified as class actions. The pending civil litigation against PG&E Corporation and the Utility related to the 2018 Camp fire, which is currently stayed as a result of the commencement of the Chapter 11 Cases, includes claims under multiple theories of liability, including inverse condemnation, trespass, private nuisance, public nuisance, negligence, negligence per se, negligent interference with prospective economic advantage, negligent infliction of emotional distress, premises liability, violations of the Public Utilities Code, violations of the Health & Safety Code, malice and false advertising in violation of the California Business and Professions Code. The plaintiffs principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2018 Camp fire. The plaintiffs seek damages and remedies that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, establishment of a class action medical monitoring fund, punitive damages, attorneys' fees and other damages. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

As of January 28, 2019, PG&E Corporation and the Utility are aware of approximately 750 complaints on behalf of at least 3,800 plaintiffs related to the 2017 Northern California wildfires, five of which seek to be certified as class actions. These cases have been coordinated in the San Francisco County Superior Court. As of the Petition Date, the coordinated litigation was in the early stages of discovery. A trial with respect to the Atlas fire was scheduled to begin on September 23, 2019. The pending civil litigation against PG&E Corporation and the Utility related to the 2017 Northern California wildfires, includes claims under multiple theories of liability, including inverse condemnation, trespass, private nuisance and negligence. This litigation, including the trial date with respect to the Atlas fire, currently is stayed as a result of the commencement of the Chapter 11 Cases. The plaintiffs principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2017 Northern California wildfires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees and other damages. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

Insurance carriers who have made payments to their insureds for property damage arising out of the 2017 Northern California wildfires have filed 48 subrogation complaints in the San Francisco County Superior Court as of January 28, 2019. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. As of January 28, 2019, insurance carriers have filed 37 similar subrogation complaints with respect to the 2018 Camp fire in the Sacramento County Superior Court. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

Various government entities, including Yuba, Nevada, Lake, Mendocino, Napa and Sonoma Counties and the Cities of Santa Rosa and Clearlake, also have asserted claims against PG&E Corporation and the Utility based on the damages that these government entities allegedly suffered as a result of the 2017 Northern California wildfires. Such alleged damages include, among other things, loss of natural resources, loss of public parks, property damages and fire suppression costs. The causes of action and allegations are similar to the ones made by individual plaintiffs and the insurance carriers. With respect to the 2018 Camp fire, Butte County has filed similar claims against PG&E Corporation and the Utility, and PG&E Corporation and the Utility expect additional similar claims to be made by other government entities. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

On March 16, 2018, PG&E Corporation and the Utility filed a demurrer to the inverse condemnation cause of action in the 2017 Northern California wildfires litigation. On May 21, 2018, the court overruled the motion. On July 20, 2018, PG&E Corporation and the Utility filed a writ in the Court of Appeal requesting appellate review of the trial court's decision, which was denied on September 17, 2018. On September 27, 2018, PG&E Corporation and the Utility filed a petition for review to the California Supreme Court. On November 14, 2018, the California Supreme Court denied PG&E Corporation's and the Utility's petition for review.

PG&E Corporation and the Utility expect to be the subject of numerous additional claims in connection with the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process.

PG&E Corporation and the Utility also are the subject of criminal investigations or other actions by the county District Attorneys to whom Cal Fire has referred its investigations into the McCourtney, Lobo, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires. Although the Honey fire was referred to the Butte County District Attorney’s Office, in October 2018, the Utility reached an agreement to settle any civil claims or criminal charges that could have been brought by the Butte County District Attorney in connection with the Honey fire, as well as the La Porte and Cherokee fires (which were not referred). The settlement provides for funding by the Utility for at least four years of an enhanced fire prevention and communication program, in the amount of up to $1.5 million, not recoverable in rates. On October 9, 2018, the District Attorney of Yuba County announced his decision not to pursue criminal charges at such time against PG&E Corporation or the Utility pertaining to the Cascade fire. The Office of the District Attorney of Yuba County also indicated that it “reserves the right to review any additional information or evidence that may be submitted to it prior to the expiration of the criminal statute of limitations.”

Also in October 2018, the Utility and the Sonoma, Napa, Lake, Humboldt and Nevada County District Attorneys entered into agreements under which the Utility agreed to waive any applicable statutes of limitation related to the 2017 Northern California wildfires that started in these counties for a period of six months, until April 8, 2019. PG&E Corporation and the Utility anticipate further discussions with the District Attorneys in these counties relating to the 2017 Northern California wildfires and whether any criminal or civil charges should be brought. In addition, the Butte County District Attorney’s Office and the California Attorney General’s Office have opened a criminal investigation of the 2018 Camp fire. Additional investigations and other actions may arise out of the other 2017 Northern California wildfires and the 2018 Camp fire. Such proceedings are not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

PG&E Corporation and the Utility are continuing to review the evidence concerning the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility have not yet had access to all of the evidence collected by Cal Fire as part of its investigations or to the many investigation reports prepared by Cal Fire. PG&E Corporation and the Utility and plaintiffs are in discussions with Cal Fire about access to the evidence and the remaining reports. No schedule on gaining access has been set.

Regardless of any determinations of cause by Cal Fire with respect to any pre-petition fire, ultimately PG&E Corporation's and the Utility's liability will be resolved through the Chapter 11 process, regulatory proceedings and any potential enforcement proceedings, all of which could take a number of years to resolve. The timing and outcome of these and other potential proceedings are uncertain.

Potential Losses in Connection with the 2018 Camp Fire and 2017 Northern California Wildfires

On January 28, 2019, the California Department of Insurance issued a news release announcing an update on property losses in connection with the 2018 wildfires in Southern California (which are not in the Utility's service territory) and the 2018 Camp fire, stating that, as of such date, "more than $11.4 billion in insured losses have been reported from the November 2018 fires," of which approximately $8.4 billion relates to statewide claims from the 2018 Camp fire. On September 6, 2018, the California Department of Insurance issued a news release announcing that insurers have received nearly 55,000 insurance claims totaling more than $12.28 billion in losses, of which approximately $10 billion relates to statewide claims from the 2017 Northern California wildfires.

The dollar amounts announced by the California Department of Insurance represent an aggregate amount of approximately $18.4 billion of insurance claims made as of the above dates related to the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation and the Utility expect that additional claims have been submitted and will continue to be submitted to insurers, particularly with respect to the 2018 Camp fire. These claims reflect insured property losses only. The $18.4 billion of insurance claims made as of the above dates does not account for uninsured or underinsured property losses, interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses or other costs, such as potential punitive damages, fines or penalties, or losses related to claims that have not manifested yet ("future claims"), each of which could be significant. The scope of all claims related to the 2018 Camp fire and 2017 Northern California wildfires is not known at this time because of the applicable statutes of limitations under California law.

Potential liabilities related to the 2018 Camp fire and 2017 Northern California wildfires depend on various factors, including but not limited to the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the extent to which future claims arise, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties or fines that may be imposed by governmental entities.

There are a number of unknown facts and legal considerations that may impact the amount of any potential liability. Among other things, it is uncertain at this time as to the number of wildfire-related claims that will be filed in the Chapter 11 Cases, the number of current and future claims that will be allowed by the Bankruptcy Court, how claims for punitive damages and claims by variously situated persons will be treated and whether such claims will be allowed, and the impact that historical settlement values for wildfire claims may have on the estimation of wildfire liability in the Chapter 11 Cases. If PG&E Corporation and the Utility were to be found liable for certain or all of the costs, expenses and other losses described above with respect to the 2018 Camp fire and 2017 Northern California wildfires, the amount of such liability could exceed $30 billion, which amount does not include potential punitive damages, fines and penalties or damages related to future claims. This estimate is based on a wide variety of data and other information available to PG&E Corporation and the Utility and their advisors, including various precedents involving similar claims, and accounts for property losses (including insured, uninsured and underinsured property losses), interest, attorneys' fees, fire suppression and clean-up costs, evacuation costs, personal injury or wrongful death damages, medical expenses and certain other costs. This estimate is not intended to provide an upper end of the range of potential liability arising from the 2018 Camp fire and 2017 Northern California wildfires. In certain circumstances, PG&E Corporation's and the Utility's liability could be substantially greater than such amount.

If PG&E Corporation and the Utility were to be found liable for any punitive damages or subject to fines or penalties, the amount of such punitive damages, fines and penalties could be significant. PG&E Corporation and the Utility have received significant fines and penalties in connection with past incidents. For example, in 2015, the CPUC approved a decision that imposed penalties on the Utility totaling $1.6 billion in connection with the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010 (the "San Bruno explosion"). These penalties represented nearly three times the underlying liability for the San Bruno explosion of approximately $558 million incurred for third-party claims, exclusive of shareholder derivative lawsuits and legal costs incurred. The amount of punitive damages, fines and penalties imposed on PG&E Corporation and the Utility could likewise be a significant amount in relation to the underlying liabilities with respect to the 2018 Camp fire and 2017 Northern California wildfires. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process. Such proceedings are not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

2018 Camp Fire and 2017 Northern California Wildfires Accounting Charge

Following accounting rules, PG&E Corporation and the Utility record a liability when a loss is probable and reasonably estimable. In accordance with U.S. generally accepted accounting principles, PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses, and record a charge that is the amount within the range that is a better estimate than any other amount or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events.

2018 Camp Fire

In light of the current state of the law and the information currently available to the Utility, including, among other things, the facts described in the EIRs and the 20-Day Electric Incident Report, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with the 2018 Camp fire, and accordingly PG&E Corporation and the Utility recorded a charge in the amount of $10.5 billion for the year ended December 31, 2018. This charge corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimated losses, and is subject to change based on additional information.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss related to the 2018 Camp fire and 2017 Northern California wildfires will be greater than the amount accrued, but are unable to reasonably estimate the additional loss and the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

The process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2018 Camp fire may change, which could result in material increases to the loss accrued.

The $10.5 billion charge does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, or punitive damages, if any, or any losses related to future claims for damages that have not manifested yet, each of which could be significant.

2017 Northern California Wildfires

In light of the current state of the law on inverse condemnation and the information currently available to the Utility, including, among other things, the Cal Fire determinations of cause as stated in Cal Fire's press releases and their released reports, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with 17 of the 2017 Northern California wildfires referred to as the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket, Atlas, Cascade, Point and Sonoma/Napa merged fires (which include the Nuns, Norrbom, Adobe, Partrick and Pythian fires). Accordingly, PG&E Corporation and the Utility recorded a charge in the amount of $2.5 billion during the quarter ended June 30, 2018 and a charge in the amount of $1.0 billion during the quarter ended December 31, 2018, for a total charge in the amount of $3.5 billion for the year ended December 31, 2018. This charge corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimated losses and is subject to change based on additional information. The additional charge recorded in the quarter ended December 31, 2018 resulted from additional information obtained by the Utility during that period about the fires.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss related to the 2017 Northern California wildfires and the 2018 Camp fire will be greater than the amount accrued, but are unable to reasonably estimate the additional loss and the upper end of the range because there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damage and losses, the nature, number and severity of personal injuries, and information made available through the discovery process.

The process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2017 Northern California wildfires may change, which could result in material increases to the loss accrued.

The $3.5 billion charge does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, or punitive damages, if any, or any losses related to future claims for damages that have not manifested yet, each of which could be significant.

The $3.5 billion charge also does not include any amounts in connection with the 37, Tubbs, Maacama and Pressley fires because at this time PG&E Corporation and the Utility have not concluded that a loss arising from those fires is probable. However, in the future it is possible that facts could emerge that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in the accrual of a liability at that time, the amount of which could be significant.

Loss Recoveries

PG&E Corporation and the Utility had insurance coverage for liabilities, including wildfire. Additionally, there are several mechanisms that allow for recovery of costs from customers. Potential for recovery is described below. Failure to obtain a substantial or full recovery of costs related to the 2018 Camp fire and 2017 Northern California wildfires or any conclusion that such recovery is no longer probable could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. In addition, the inability to recover costs in in a timely manner could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Insurance

PG&E Corporation and the Utility had $842 million of insurance coverage for liabilities, including wildfire events, for the period from August 1, 2017 through July 31, 2018, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. During the third quarter of 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019, comprised of $700 million for general liability (subject to an initial self-insured retention of $10 million per occurrence), and $700 million for property damages only, which property damage coverage includes an aggregate amount of approximately $200 million through the reinsurance market where a catastrophe bond was utilized. PG&E Corporation and the Utility expect to face increasing difficulty securing liability insurance in future years due to availability and to face significantly increased insurance costs.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through December 31, 2018, PG&E Corporation and the Utility recorded $1.38 billion for probable insurance recoveries in connection with the 2018 Camp fire and $842 million for probable insurance recoveries in connection with the 2017 Northern California wildfires. These amounts reflect an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. The amount of the receivable is subject to change based on additional information. PG&E Corporation and the Utility intend to seek full recovery for all insured losses and believe it is reasonably possible that they will record a receivable for the full amount of the insurance limits in the future.

If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected. Even if PG&E Corporation and the Utility were to recover the full amount of their insurance, PG&E Corporation and the Utility expect their losses in connection with the 2018 Camp fire and 2017 Northern California wildfires will greatly exceed their available insurance.

The following table presents changes in the insurance receivable for the year ended December 31, 2018. The balance for insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

(in millions)	**Insurance Receivable**
2018 Camp fire	
Accrued insurance recoveries	$ 1,380
Reimbursements	—
Balance at December 31, 2018	**$ 1,380**
2017 Northern California wildfires	
Accrued insurance recoveries	$ 842
Reimbursements	(13)
Balance at December 31, 2018	**$ 829**

Regulatory Recovery

On June 21, 2018, the CPUC issued a decision granting the Utility's request to establish a WEMA to track specific incremental wildfire liability costs effective as of July 26, 2017. The decision does not grant the Utility rate recovery of any wildfire-related costs. Any such rate recovery would require CPUC authorization in a separate proceeding. The Utility may be unable to fully recover costs in excess of insurance, if at all. Rate recovery is uncertain, therefore the Utility has not recorded a regulatory asset related to any wildfire claims costs. Even if such recovery is possible, it could take a number of years to resolve and a number of years to collect.

In addition, SB 901, signed into law on September 21, 2018, requires the CPUC to establish a customer harm threshold, directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the maximum amount that the Utility can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service (the "Customer Harm Threshold"). SB 901 also authorizes the CPUC to issue a financing order that permits recovery, through the issuance of recovery bonds (also referred to as "securitization"), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the Customer Harm Threshold. SB 901 does not authorize securitization with respect to possible 2018 Camp fire costs, as the bill does not address fires that occurred in 2018.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the Customer Harm Threshold in future applications under Section 451.2(a) of the Public Utilities Code for cost recovery of 2017 wildfire costs. In the OIR, the CPUC stated that "consistent with Section 451.2(a), the determination of what costs and expenses are just and reasonable must be made in the context of an application for the recovery of specific costs related to the 2017 wildfires." Following the CPUC's interpretation of Section 451.2 as outlined in the OIR, PG&E Corporation and the Utility believe that any securitization of costs relating to the 2017 Northern California wildfires would not occur, if at all, until (a) the Utility has paid claims relating to the 2017 Northern California wildfires, (b) the Utility has filed application for recovery of such costs and (c) the CPUC makes a determination that such costs are just and reasonable or in excess of the Customer Harm Threshold. PG&E Corporation and the Utility therefore do not expect the CPUC to permit the Utility to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis unless the CPUC alters the position expressed in the OIR.

On February 11, 2019, PG&E Corporation and the Utility filed opening comments in response to the OIR in which they argued, among other things, the CPUC should (1) promptly set a Customer Harm Threshold, or at least define the methodology for setting the Customer Harm Threshold with sufficient specificity to enable PG&E Corporation and the Utility and potential investors to anticipate that amount; (2) determine the Customer Harm Threshold based on the capital needed to resolve claims arising from both the 2018 Camp fire and 2017 Northern California wildfires to be provided for in a plan of reorganization; (3) define how the Customer Harm Threshold will be applied to any future wildfires; and (4) establish the Customer Harm Threshold based on the amount of debt PG&E Corporation and the Utility can raise. Based on assumptions set forth in the comments, PG&E Corporation and the Utility indicated that they could borrow up to approximately $3 billion to fund wildfire claims costs as part of a plan of reorganization.

Failure to obtain a substantial or full recovery of costs related to the 2018 Camp fire and 2017 Northern California wildfires or any conclusion that such recovery is no longer probable could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows.

Wildfire-Related Derivative Litigation

Two purported derivative lawsuits alleging claims for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively, naming as defendants current and certain former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation and the Utility are named as nominal defendants. These lawsuits were consolidated by the court on February 14, 2018, and are denominated *In Re California North Bay Fire Derivative Litigation*. On April 13, 2018, the plaintiffs filed a consolidated complaint. After the parties reached an agreement regarding a stay of the derivative proceeding pending resolution of the tort actions described above and any regulatory proceeding relating to the 2017 Northern California wildfires, on April 24, 2018, the court entered a stipulation and order to stay. The stay is subject to certain conditions regarding the plaintiffs' access to discovery in other actions. On January 28, 2019, the plaintiffs filed a request to lift the stay for the purposes of amending their complaint to add allegations regarding the 2018 Camp fire.

On August 3, 2018, a third purported derivative lawsuit, entitled *Oklahoma Firefighters Pension and Retirement System v. Chew, et al.*, was filed in the U.S. District Court for the Northern District of California, naming as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation is named as a nominal defendant. The lawsuit alleges claims for breach of fiduciary duties and unjust enrichment as well as a claim under Section 14(a) of the federal Securities Exchange Act of 1934 alleging that PG&E Corporation's and the Utility's 2017 proxy statement contained misrepresentations regarding the companies' risk management and safety programs. On October 15, 2018, PG&E Corporation filed a motion to stay the litigation. The hearing on this motion, previously set for January 31, 2019, was moved by stipulation of the parties and order of the court to March 7, 2019.

On October 23, 2018, a fourth purported derivative lawsuit, entitled *City of Warren Police and Fire Retirement System v. Chew, et al.,* was filed in San Francisco County Superior Court, alleging claims for breach of fiduciary duty, corporate waste and unjust enrichment. It names as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation, and names PG&E Corporation as a nominal defendant. Plaintiff filed a request with the court seeking the voluntary dismissal of this matter without prejudice on January 18, 2019.

On November 21, 2018, a fifth purported derivative lawsuit, entitled *Williams v. Earley, Jr., et al.*, was filed in federal court in San Francisco, alleging claims identical to those alleged in the *Oklahoma Firefighters Pension and Retirement System v. Chew, et al*. lawsuit listed above against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. This lawsuit includes allegations related to the 2017 Northern California wildfires and the 2018 Camp fire. This action was stayed by stipulation of the parties and order of the court on December 21, 2018, subject to resolution of the pending securities class action.

On December 24, 2018, a sixth purported derivative lawsuit, entitled *Bowlinger v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. The court scheduled an initial case management conference for March 21, 2019.

On January 25, 2019, a seventh purported derivative lawsuit, entitled *Hagberg v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants.

On January 28, 2019, an eighth purported derivative lawsuit, entitled *Blackburn v. Meserve, et al.*, was filed in federal court alleging claims for breach of fiduciary duty, unjust enrichment, and waste of corporate assets in connection with the 2017 Northern California wildfires and the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation as a nominal defendant.

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed notices in each of these proceedings on February 1, 2019, reflecting that the proceedings are automatically stayed pursuant to Section 362(a) of the Bankruptcy Code. On February 5, 2019, the plaintiff in *Bowlinger v. Chew, et al.* filed a response to the notice asserting that the automatic stay did not apply to his claims. The court has not yet acted on the plaintiff’s response.

Wildfire-Related Securities Class Action Litigation

In June 2018, two purported securities class actions were filed in the United States District Court for the Northern District of California, naming PG&E Corporation and certain of its current and former officers as defendants, entitled *David C. Weston v. PG&E Corporation, et al.* and *Jon Paul Moretti v. PG&E Corporation, et al.*, respectively. The complaints alleged material misrepresentations and omissions related to, among other things, vegetation management and transmission line safety in various PG&E Corporation public disclosures. The complaints asserted claims under Section 10(b) and Section 20(a) of the federal Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, interest, attorneys' fees and other costs. Both complaints identified a proposed class period of April 29, 2015 to June 8, 2018. On September 10, 2018, the court consolidated both cases and the litigation is now denominated *In Re PG&E Corporation Securities Litigation*. The court also appointed the Public Employees Retirement Association of New Mexico as lead plaintiff. The plaintiff filed a consolidated amended complaint on November 9, 2018. After the plaintiff requested leave to amend their complaint to add allegations regarding the 2018 Camp fire, the plaintiff filed a second amended consolidated complaint on December 14, 2018.

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed a notice on February 1, 2019, reflecting that the proceedings are automatically stayed pursuant to Section 362(a) of the Bankruptcy Code. On February 15, 2019, PG&E Corporation and the Utility filed a complaint in Bankruptcy Court against the plaintiff seeking preliminary and permanent injunctive relief to extend the stay to the claims alleged against the individual officer defendants.

On February 22, 2019, a purported securities class action was filed in the United States District Court for the Northern District of California, entitled *York County on behalf of the York County Retirement Fund, et al. v. Rambo, et al*. The complaint names as defendants certain current and former officers and directors, as well as the underwriters of 4 public offerings of notes from 2016 to 2018. Neither PG&E Corporation nor the Utility is named as a defendant. The complaint alleges material misrepresentations and omissions in connection with the note offerings related to, among other things, PG&E Corporation’s and the Utility’s vegetation management and wildfire safety measures. The complaint asserts claims under Section 11 and Section 15 of the federal Securities Act of 1933, and seeks unspecified monetary relief, attorneys’ fees and other costs, and injunctive relief. If necessary, PG&E Corporation and the Utility intend to file a complaint in Bankruptcy Court against the plaintiffs seeking preliminary and permanent injunctive relief to extend the stay to the claims alleged against the individual officer and director defendants.

Clean-up and Repair Costs

The Utility incurred costs of $354 million for clean-up and repair of the Utility’s facilities (including $183 million in capital expenditures) through December 31, 2018, in connection with the 2018 Camp fire. The Utility also incurred costs of $327 million for clean-up and repair of the Utility’s facilities (including $157 million in capital expenditures) through December 31, 2018, in connection with the 2017 Northern California wildfires. The Utility is authorized to track and seek recovery of clean-up and repair costs through CEMA. (CEMA requests are subject to CPUC approval.) The Utility capitalizes and records as regulatory assets costs that are probable of recovery. At December 31, 2018, the CEMA balance related to the 2017 Northern California wildfires was $82 million and is included in long-term regulatory assets on the Consolidated Balance Sheets. Additionally, the capital expenditures for clean-up and repair are included in property, plant and equipment at December 31, 2018.

Should PG&E Corporation and the Utility conclude that recovery of any clean-up and repair costs included in the CEMA is no longer probable, PG&E Corporation and the Utility will record a charge in the period such conclusion is reached. Failure to obtain a substantial or full recovery of these costs or any conclusion that such recovery is no longer probable, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

2015 Butte Fire

In September 2015, a wildfire (the "2015 Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the 2015 Butte fire. According to Cal Fire's report, the 2015 Butte fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the 2015 Butte fire was caused when a gray pine tree contacted the Utility's electric line, which ignited portions of the tree and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California, County of Sacramento. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council previously had authorized the coordination of all cases in Sacramento County. As of January 31, 2019, 95 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,900 individual plaintiffs representing approximately 2,000 households and their insurance companies. These complaints are part of, or were in the process of being added to, the coordinated proceeding. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. Several plaintiffs dismissed the Utility's two vegetation management contractors from their complaints. The Utility does not expect the number of claimants to increase significantly in the future, because the statute of limitations for property damage and personal injury in connection with the 2015 Butte fire has expired. Further, due to the commencement of the Chapter 11 Cases, these plaintiffs have been stayed from continuing to prosecute pending litigation and from commencing new lawsuits against PG&E Corporation or the Utility on account of pre-petition obligations. On January 30, 2019, the Court in the coordinated proceeding issued an order staying the action.

On April 28, 2017, the Utility moved for summary adjudication on plaintiffs' claims for punitive damages. The court denied the Utility's motion and the Utility filed a writ with the Court of Appeal of the State of California, Third Appellate District. The writ was granted on July 2, 2018, directing the trial court to enter summary adjudication in favor of the Utility and to deny plaintiffs' claim for punitive damages under California Civil Code Section 3294. Plaintiffs sought rehearing and asked the California Supreme Court to review the Court of Appeal's decision. Both requests were denied. Neither the trial nor appellate courts originally addressed whether plaintiffs can seek punitive damages at trial under Public Utilities Code Section 2106. However, the trial court, in November 2018, denied a motion filed by the Utility that would have confirmed that punitive damages under Public Utilities Code Section 2106 are unavailable. The Utility believes a loss related to punitive damages is unlikely, but possible.

On June 22, 2017, the Superior Court of California, County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inverse condemnation applies to the Utility with respect to the 2015 Butte fire. The court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding at the time of the ruling, others could make similar claims. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases.

On May 1, 2018, the Superior Court of California, County of Sacramento issued its ruling on the Utility's renewed motion in which the court affirmed, with minor changes, its tentative ruling dated April 25, 2018. The court determined that it is bound by earlier holdings of two appellate courts decisions, *Barham* and *Pacific Bell*. Further, the court stated that the Utility's constitutional arguments should be made to the appellate courts and suggested that, to the extent the Utility raises the public policy implications of the November 30, 2017 CPUC decision in the San Diego Gas & Electric Company cost recovery proceeding, these arguments should be addressed to the Legislature or CPUC. The Utility filed a writ with the Court of Appeal seeking immediate review of the court's decision. On June 18, 2018, after the writ was summarily denied, the Utility filed a Petition for Review with the California Supreme Court, which also was denied. On September 6, 2018, the court set a trial for some individual plaintiffs to begin on April 1, 2019. The Utility reached agreement with two plaintiffs in the litigation to stipulate to judgment against the Utility on inverse condemnation grounds. The court granted the Utility's stipulated judgment motion on November 29, 2018 and the Utility filed its appeal on December 11, 2018. As a result of the filing of the Chapter 11 Cases, these lawsuits, including the trial and the appeal from the stipulated judgment, are stayed.

In addition to the coordinated plaintiffs, Cal Fire, the California Office of Emergency Services (the "OES"), the County of Calaveras, and five smaller public entities (three fire districts, one water district and the California Department of Veterans Affairs) have brought suit or indicated that they intend to do so. The five smaller public entities filed their complaints in August 2018 and September 2018. They have been added to the coordinated proceedings. The Utility has settled the claims of the three fire protection districts.

On April 13, 2017, Cal Fire filed a complaint with the Superior Court of California, County of Calaveras, seeking to recover over $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, or violated the law, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Trees, Inc., one of the Utility's vegetation contractors. Cal Fire had requested that a trial of its claims be set in 2019, following any trial of the claims of the individual plaintiffs. On October 19, 2018, the Utility filed a motion for summary judgment arguing that Cal Fire cannot recover any fire suppression costs under the Third District Court of Appeal's decision in *Dep't of Forestry & Fire Prot. v. Howell* (2017) 18 Cal. App. 5th 154. The hearing on that motion was set for January 31, 2019, but the hearing and Cal Fire's case against the Utility are now stayed. Prior to the stay, the Utility and Cal Fire were also engaged in a mediation process.

Also, on February 20, 2018, the County of Calaveras filed suit against the Utility and the Utility's vegetation management contractors to recover damages and other costs, based on the doctrine of inverse condemnation and negligence theory of liability. The County also sought punitive damages. On March 2, 2018, the County served a mediation demand seeking in excess of $167 million, having previously indicated that it intended to bring an approximately $85 million claim against the Utility. This claim included costs that the County of Calaveras allegedly incurred or expected to incur for infrastructure damage, erosion control, and other costs. The Utility and the County of Calaveras settled the County's claims in November 2018 for $25.4 million.

Further, in May 2017, the OES indicated that it intended to bring a claim against the Utility that it estimated to be approximately $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the 2015 Butte fire. The Utility has not received any information or documentation from OES since its May 2017 statement. In June 2017, the Utility entered into an agreement with the OES that extends their deadline to file a claim to December 2020.

PG&E Corporation's and the Utility's obligations with respect to such outstanding claims are expected to be determined through the Chapter 11 process.

Estimated Losses from Third-Party Claims

In connection with the 2015 Butte fire, the Utility may be liable for property damages, business interruption, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation.

In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility is found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court would agree with the Utility.

The Utility's assessment of the estimated loss related to the 2015 Butte fire is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and certain other damages.

The Utility has determined that it is probable that it will incur a loss of $1.1 billion in connection with the 2015 Butte fire. While this amount includes the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any portion of the estimated claim from the OES. The Utility still does not have sufficient information to reasonably estimate any liability it may have for that additional claim.

The process for estimating costs associated with claims relating to the 2015 Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, management estimates and assumptions regarding the financial impact of the 2015 Butte fire may result in material increases to the loss accrued.

The following table presents changes in the third-party claims liability since December 31, 2015. The balance for the third-party claims liability is included in Wildfire-related claims in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

Loss Accrual (in millions)		
Balance at December 31, 2015	$	—
Accrued losses		750
Payments [1]		(60)
Balance at December 31, 2016		**690**
Accrued losses		350
Payments [1]		(479)
Balance at December 31, 2017		**561**
Accrued losses		—
Payments [1]		(335)
Balance at December 31, 2018	**$**	**226**

[1] As of December 31, 2018, the Utility has paid $874 million of the $904 million in settlements to date in connection with the 2015 Butte fire.

If the Utility records losses in connection with claims relating to the 2015 Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected in the reporting periods during which additional charges are recorded.

Loss Recoveries

The Utility has liability insurance from various insurers, that provides coverage for third-party liability attributable to the 2015 Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through December 31, 2018, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the 2015 Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility has received $60 million in cumulative reimbursements from the insurance policies of its vegetation management contractors (excluded from the table below), including $7 million received in the year ended December 31, 2018. Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

Insurance Receivable (in millions)		
Balance at December 31, 2015	$	—
Accrued insurance recoveries		625
Reimbursements		(50)
Balance at December 31, 2016		**575**
Accrued insurance recoveries		297
Reimbursements		(276)
Balance at December 31, 2017		**596**
Accrued insurance recoveries		—
Reimbursements		(511)
Balance at December 31, 2018	**$**	**85**

In January and February 2019, the Utility received an additional $25 million in insurance reimbursements.

NOTE 14: OTHER CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the outcome of the following matters.

Enforcement Matters

In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations. It is uncertain whether any charges will be brought against the Utility. Such proceedings are not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

CPUC and FERC Matters

Order Instituting an Investigation and Order to Show Cause into the Utility's Locate and Mark practices

On December 14, 2018, the CPUC issued an OII and order to show cause (the "OII") to assess the Utility's practices and procedures related to the locating and marking of natural gas facilities. The OII directs the Utility to show cause as to why the Commission should not find violations in this matter, and why the Commission should not impose penalties, and/or any other forms of relief, if any violations are found. The Utility also is directed in the OII to provide a report on specific matters, including that it is conducting locate and mark programs in a safe manner.

The OII cites a report by the SED dated December 6, 2018, which alleges that the Utility violated the law pertaining to the locating and marking of its gas facilities and falsified records related to its locate and mark activities between 2012 and 2017. As described in the OII, the SED cites reports issued in this matter by two consultants retained by the Utility, that (i) included certain facts and conclusions about the extent of inaccuracies in the Utility's late tickets and the reasons for the inaccuracies, and (ii) provided the Utility's late tickets counts, and identification of associated dig-ins. As a result, the OII will determine whether the Utility violated any provision of the Public Utilities Code, general orders, federal law adopted by California, other rules, or requirements, and/or other state or federal law, by its locate and mark policies, practices, and related issues, and the extent to which the Utility's practices with regard to locate and mark may have diminished system safety.

The CPUC indicates that it has not concluded that the Utility has violated the law in any instance pertaining to late tickets, locating and marking, or any matter related to either, or to any other matter raised in this OII. However, if violations are found, the CPUC will consider what monetary fines and other remedies are appropriate, will review the duration of violations and, if supported by the evidence, it will consider ordering daily fines.

On January 14, 2019, the Utility submitted responses to preliminary questions raised in the OII and separately filed an affidavit regarding the safety of the locate and mark program. On March 14, 2019, as directed by the CPUC, the Utility expects to submit a report that addresses the SED report and respond to the order to show cause. A schedule for future proceedings is expected to be established at an April 5, 2019 pre-hearing conference.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties, including fines or other remedies, on the Utility. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining penalties. The Utility is unable to predict the timing and outcome of this proceeding.

Such proceedings are likely not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have occurred or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC’s Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno’s July 2014 motion, which it filed in CPUC investigations related to the Utility’s natural gas transmission pipeline operations and practices.

On April 26, 2018, the CPUC approved the revised proposed decision issued on April 3, 2018, adopting the settlement agreement jointly submitted to the CPUC on March 28, 2017, as modified (the "settlement agreement") by the Utility, the Cities of San Bruno and San Carlos, Cal PA, the SED, and TURN.

The decision results in a total penalty of $97.5 million comprised of: (1) a $12 million payment to the California General Fund, (2) forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million), (3) a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over the Utility’s next GRC cycle (i.e., the 2020 GRC), and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above.

As a result of the CPUC's April 26, 2018 decision, on May 17, 2018, the Utility made a $12 million payment to the California General Fund and $6 million payments to each of the Cities of San Bruno and San Carlos. At December 31, 2018, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $32 million accrual for a portion of the 2018 GT&S revenue requirement reduction. In accordance with accounting rules, adjustments related to revenue requirements are recorded in the periods in which they are incurred.

The CPUC also ordered a second phase in this proceeding to determine if any of the additional communications that the Utility reported to the CPUC on September 21, 2017, violate the CPUC ex parte rules. On May 22, 2018, the assigned ALJ issued a ruling requiring the parties to meet and confer to determine if an agreement can be reached on the issues identified by the ALJ. On September 17, 2018, the parties submitted a joint status report indicating a settlement in principle could not be reached. The ALJ will hold a prehearing conference with the parties to determine if evidentiary hearings are required. The Utility is unable to predict the timing and outcome of the second phase in this proceeding.

Such proceedings are likely not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

Transmission Owner Rate Case Revenue Subject to Refund

The FERC determines the amount of authorized revenue requirements, including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. The Utility bills and records revenue based on the amounts requested in its rate case filing and records a reserve for its estimate of the amounts that are probable of refund. Rates subject to refund went into effect on March 1, 2017, and March 1, 2018, for TO18 and TO19, respectively. Rates subject to refund for TO20 will go into effect on May 1, 2019.

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case and the Utility filed initial briefs on October 31, 2018, in response to the ALJ's recommendations. The Utility expects the FERC to issue a decision in the TO18 rate case by mid-2019, however, that decision will likely be the subject of requests for rehearing and appeal. The Utility is unable to predict the timing of when a final decision will be issued. On September 21, 2018, the Utility filed an all-party settlement with FERC in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined in the TO18 final decision. The Utility is unable to predict the timing or outcome of FERC's decisions in these proceedings.

Natural Gas Transmission Pipeline Rights-of-Way

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to address a self-reported violation whereby the Utility did not properly identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

Other Matters

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed in Note 13 and above under "Enforcement and Litigation Matters") totaled $98 million at December 31, 2018 and $86 million at December 31, 2017. These amounts are included in Other current liabilities in the Consolidated Balance Sheets. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material effect on their financial condition, results of operations, liquidity, and cash flows.

2015 GT&S Rate Case Disallowance of Capital Expenditures

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted in the prior GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also established various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way balancing accounts. As a result, in 2016, the Utility incurred charges of $219 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This included $134 million for 2011 through 2014 capital expenditures in excess of adopted amounts and $44 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. The Utility would be required to take a charge in the future if the CPUC's audit of 2011 through 2014 capital spending resulted in additional permanent disallowance. The audit is still in process.

Environmental Remediation Contingencies

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Key factors that inform the development of estimated costs include site feasibility studies and investigations, applicable remediation actions, operations and maintenance activities, post-remediation monitoring, and the cost of technologies that are expected to be approved to remediate the site. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is comprised of the following:

	Balance at	
(in millions)	**December 31, 2018**	**December 31, 2017**
Topock natural gas compressor station	$ 369	$ 334
Hinkley natural gas compressor station	146	147
Former manufactured gas plant sites owned by the Utility or third parties (1)	520	320
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2)	111	115
Fossil fuel-fired generation facilities and sites (3)	137	123
Total environmental remediation liability	**$ 1,283**	**$ 1,039**

(1) Primarily driven by the following sites: Vallejo, San Francisco East Harbor, Napa, and San Francisco North Beach.

(2) Primarily driven by Geothermal landfill and Shell Pond site.

(3) Primarily driven by the San Francisco Potrero Power Plant.

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the EPA under the Federal Resource Conservation and Recovery Act in addition to other state hazardous waste laws. The Utility has a comprehensive program in place designed to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements. The Utility assesses and monitors the environmental requirements on an ongoing basis, and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at December 31, 2018, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans and the Utility's time frame for remediation. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material effect on results of operations, financial condition, liquidity, and cash flows during the period in which they are recorded. At December 31, 2018, the Utility expected to recover $930 million of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California DTSC and the U.S. Department of the Interior. On April 24, 2018, the DTSC authorized the Utility to build an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. Construction activities began in October 2018 and will continue for several years. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $303 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. The background study is expected to be finalized in 2019. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $141 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has undertaken a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $518 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites often involve long-term remediation. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $135 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Fossil Fuel-Fired Generation Sites

In 1998, the Utility divested its generation power plant business as part of generation deregulation. Although the Utility sold its fossil-fueled power plants, the Utility retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $105 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Insurance

Wildfire Insurance

In 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019, comprised of $700 million for general liability (subject to an initial self-insured retention of $10 million per occurrence), and $700 million for property damages only, which property damage coverage includes an aggregate amount of approximately $200 million through the reinsurance market where a catastrophe bond was utilized. Various coverage limitations applicable to different insurance layers could result in substantial uninsured costs in the future depending on the amount and type of damages.

PG&E Corporation's and the Utility's cost of obtaining wildfire insurance coverage has increased to $360 million, compared to the adopted approximately $50 million that the Utility is currently recovering through rates through December 31, 2019. The Utility intends to seek recovery for the full amount of premium costs paid in excess of the amount the Utility currently is recovering from customers through the end of the current GRC period, which ends on December 31, 2019.

Nuclear Insurance

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain reimbursement from the federal government up to a shared limit of $3.2 billion for each insured loss for NEIL members. In contrast, for acts of terrorism not deemed "certified" by the Secretary of the Treasury, NEIL treats all non-certified terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share a $3.2 billion policy limit amount.

In addition to the nuclear insurance the Utility maintains through the NEIL, the Utility also is a member of the EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at Diablo Canyon. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2018, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $47 million. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $3 million, as of December 31, 2018.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $14.1 billion. The Utility purchased the maximum available public liability insurance of $450 million for Diablo Canyon. The balance of the $14.1 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $275 million per nuclear incident under this program, with payments in each year limited to a maximum of $41 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $450 million per incident. In addition, the Utility has $53 million of liability insurance for Humboldt Bay Unit 3 and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents for Humboldt Bay Unit 3, covering liabilities in excess of the $53 million in liability insurance.

Resolution of Remaining 2001 Chapter 11 Disputed Claims

Various electricity suppliers filed claims in the Utility's 2001 prior proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility pursued settlements with electricity suppliers and entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties, in some instances, would be subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

At December 31, 2018 and December 31, 2017, respectively, the Consolidated Balance Sheets reflected $220 million and $243 million in net claims within Disputed claims and customer refunds related to the 2001 Chapter 11 proceeding. The Utility's obligations with respect to such claims (all of which arose prior to the initiation of the Utility's pending Chapter 11 Case on January 29, 2019), including pursuant to any prior settlements relating thereto, are expected to be determined through the proceedings of the Chapter 11 Cases.

Purchase Commitments

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2018:

	Power Purchase Agreements					
(in millions)	**Renewable Energy**	**Conventional Energy**	**Other**	**Natural Gas**	**Nuclear Fuel**	**Total**
2019	$ 2,221	$ 642	$ 108	$ 412	$ 108	$ 3,491
2020	2,183	639	83	153	151	3,209
2021	2,174	582	65	93	64	2,978
2022	1,984	511	61	93	54	2,703
2023	1,914	223	61	93	49	2,340
Thereafter	24,217	435	162	264	47	25,125
Total purchase commitments	**$ 34,693**	**$ 3,032**	**$ 540**	**$ 1,108**	**$ 473**	**$ 39,846**

Subject to certain exceptions, under the Bankruptcy Code, PG&E Corporation and the Utility may assume, assign or reject certain executory contracts and unexpired leases, subject to the approval of the Bankruptcy Court and satisfaction of certain other conditions. (For more information see "Chapter 11 Proceedings" in Note 15 below.)

Third-Party Power Purchase Agreements

In the ordinary course of business, the Utility enters into various agreements, including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

Renewable Energy Power Purchase Agreements. In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow. As of December 31, 2018, renewable energy contracts expire at various dates between 2019 and 2043.

Conventional Energy Power Purchase Agreements. The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2018, these power purchase agreements expire at various dates between 2019 and 2033.

Other Power Purchase Agreements. The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Two of these agreements are treated as capital leases. At December 31, 2018 and 2017, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $11 million and $18 million including accumulated amortization of $8 million and $143 million, respectively. The present value of the future minimum lease payments due under these agreements included $2 million and $11 million in Current Liabilities and $9 million and $7 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2018, QF contracts in operation expire at various dates between 2019 and 2049. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The costs incurred for all power purchases and electric capacity amounted to $3.1 billion in 2018, $3.3 billion in 2017, and $3.5 billion in 2016.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2019 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California to more reliably meet customers' loads.

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $0.6 billion in 2018, $0.9 billion in 2017, and $0.7 billion in 2016.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2019 and 2024 and are intended to ensure long-term nuclear fuel supply. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to $73 million in 2018, $83 million in 2017, and $100 million in 2016.

Other Commitments

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2019 and 2052. At December 31, 2018, the future minimum payments related to these commitments were as follows:

(in millions)	Operating Leases
2019	$ 44
2020	41
2021	36
2022	28

2023		19
Thereafter		121
Total minimum lease payments	**$**	**289**

Payments for other commitments related to operating leases amounted to $43 million in 2018, $45 million in 2017, and $43 million in 2016. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

NOTE 15: SUBSEQUENT EVENTS

Chapter 11 Proceedings

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. PG&E Corporation's and the Utility's Chapter 11 Cases are being jointly administered under the caption In re: PG&E Corporation and Pacific Gas and Electric Company, Case No. 19-30088 (DM).

PG&E Corporation and the Utility continue to operate their businesses as debtors in possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. As debtors in possession, PG&E Corporation and the Utility are authorized to continue to operate as ongoing businesses, and may pay all debts and honor all obligations arising in the ordinary course of their businesses after the Petition Date. However, PG&E Corporation and the Utility may not pay third-party claims or creditors on account of obligations arising before the Petition Date or engage in transactions outside the ordinary course of business without approval of the Bankruptcy Court.

Under the Bankruptcy Code, third-party actions to collect pre-petition indebtedness owed by PG&E Corporation or the Utility, as well as most litigation pending against PG&E Corporation and the Utility (including the third-party matters described in Note 13 above), are subject to an automatic stay. Absent an order of the Bankruptcy Court providing otherwise, substantially all pre-petition liabilities will be administered under a Chapter 11 plan of reorganization to be voted upon by creditors and other stakeholders, and approved by the Bankruptcy Court. However, under the Bankruptcy Code, regulatory or criminal proceedings are generally not subject to an automatic stay, and PG&E Corporation and the Utility expect these proceedings to continue during the pendency of the Chapter 11 Cases.

To assure ordinary course operations, on January 31, 2019, PG&E Corporation and the Utility received interim approval from the Bankruptcy Court on a variety of "first day" motions, including motions that authorize them to maintain their existing cash management system, to continue wage and salary payments and other benefits to their employees, to secure debtor in possession financing and other customary relief. On February 27, 2019, PG&E Corporation and the Utility received final approval of the first day motion to continue wage and salary payments and other benefits to their employees (with one limited objection with respect to a discrete matter having been preserved by the Bankruptcy Court) and certain other first day motions for customary relief. Hearings on certain other first day motions, including a hearing to consider final approval of PG&E Corporation's and the Utility's motions to continue their existing cash management system and to approve their debtor in possession financing, have not been held and no assurances can be given that the Bankruptcy Court will approve such motions on a final basis. PG&E Corporation and the Utility are unable to predict the date of the final hearing with respect to such motions, but there are hearings currently scheduled for March 12, March 13 and March 27, 2019.

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement. See Note 4 above for a description of the DIP Credit Agreement.

The commencement of the Chapter 11 Cases constituted an event of default or termination event, and caused an automatic and immediate acceleration of the Accelerated Direct Financial Obligations. Accordingly, as a result of the commencement of the Chapter 11 Cases, the principal amount of the Accelerated Direct Financial Obligations, together with accrued interest thereon, and in case of certain indebtedness, premium, if any, thereon, immediately became due and payable. However, any efforts to enforce such payment obligations are automatically stayed as of the Petition Date, and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The material Accelerated Direct Financial Obligations include the outstanding senior notes, agreements in respect of certain series of pollution control bonds, and PG&E Corporation's term loan facility, as well as short-term borrowings under PG&E Corporation's and the Utility's revolving credit facilities and the Utility's term loan facility disclosed in Note 4 above. The filing of the Chapter 11 Cases may also provide the counterparties under certain commodity and related agreements with the right to declare an event of default and to seek termination of such rights subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

Under the priority scheme established by the Bankruptcy Code, certain post-petition and secured or “priority” pre-petition liabilities need to be satisfied before general unsecured creditors and holders of PG&E Corporation's and the Utility’s equity are entitled to receive any distribution. No assurance can be given as to what values, if any, will be ascribed in the Chapter 11 Cases to the claims and interests of each of these constituencies. Additionally, no assurance can be given as to whether, when or in what form unsecured creditors and holders of PG&E Corporation’s or the Utility’s equity may receive a distribution on such claims or interests.

Under the Bankruptcy Code, PG&E Corporation and the Utility may assume, assume and assign, or reject certain executory contracts and unexpired leases, including, without limitation, leases of real property and equipment, subject to the approval of the Bankruptcy Court and to certain other conditions. Any description of an executory contract or unexpired lease in this Annual Report on Form 10-K, including, where applicable, the express termination rights thereunder or a quantification of their obligations, must be read in conjunction with, and is qualified by, any overriding rejection rights PG&E Corporation and the Utility have under the Bankruptcy Code.

As of February 28, 2019, the Utility had outstanding borrowings of $350 million under the DIP Revolving Facility and $30 million in face amount of outstanding letters of credit, with remaining availability of $1.12 billion under the DIP Revolving Facility.

US District Court Matters and Probation

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court issued a judgment of conviction against the Utility. The court sentenced the Utility to a 5-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after 3 years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service.

The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility has retained a third-party monitor at the Utility’s expense. The goal of the third-party monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations, and to maintain effective ethics, compliance and safety related incentive programs on a Utility-wide basis.

On November 27, 2018, the court overseeing the Utility's probation, issued an order requiring that the Utility, the United States Attorney's Office for the Northern District of California (the "USAO") and the third-party monitor provide written answers to a series of questions regarding the Utility's compliance with the terms of its probation, including what requirements of the Utility's probation "might be implicated were any wildfire started by reckless operation or maintenance of PG&E power lines" or "might be implicated by any inaccurate, slow, or failed reporting of information about any wildfire by PG&E." The court also ordered the Utility to provide "an accurate and complete statement of the role, if any, of PG&E in causing and reporting the recent 2018 Camp fire in Butte County and all other wildfires in California" since January 2017 ("Question 4 of the November 27 Order"). On December 5, 2018, the court issued an order requesting that the Office of the California Attorney General advise the court of its view on "the extent to which, if at all, the reckless operation or maintenance of PG&E power lines would constitute a crime under California law." The responses of the Attorney General were submitted on December 28, 2018, and the responses of the Utility, the USAO and the third-party monitor were submitted on December 31, 2018.

On January 3, 2019, the court issued a new order requiring that the Utility provide further information regarding the Atlas fire. The court noted that "[t]his order postpones the question of the adequacy of PG&E's response" to Question 4 of the November 27 Order. On January 4, 2019, the court issued another order requiring that the Utility provide "with respect to each of the eighteen October 2017 Northern California wildfires that [Cal Fire] has attributed to [the Utility's] facilities," information regarding the wind conditions in the vicinity of each fire's origin and information about the equipment allegedly involved in each fire's ignition. The responses of the Utility were submitted on January 10, 2019.

On January 9, 2019, the court ordered the Utility to appear in court on January 30, 2019, as a result of the court's finding that "there is probable cause to believe there has been a violation of the conditions of supervision" with respect to reporting requirements related to the 2017 Honey fire. In addition, on January 9, 2019, the court issued an order (the "January 9 Order") proposing to add new conditions of probation that would require the Utility, among other things, to:

- prior to June 21, 2019, "re-inspect all of its electrical grid and remove or trim all trees that could fall onto its power lines, poles or equipment in high-wind conditions, . . . identify and fix all conductors that might swing together and arc due to slack and/or other circumstances under high-wind conditions[,] identify and fix damaged or weakened poles, transformers, fuses and other connectors [and] identify and fix any other condition anywhere in its grid similar to any condition that contributed to any previous wildfires",

- "document the foregoing inspections and the work done and . . . rate each segment's safety under various wind conditions" and

- at all times from and after June 21, 2019, "supply electricity only through those parts of its electrical grid it has determined to be safe under the wind conditions then prevailing."

The Utility was ordered to show cause by January 23, 2019, as to why the Utility's conditions of probation should not be modified as proposed. The Utility's response was submitted on January 23, 2019. The court requested that Cal Fire file a public statement, and invited the CPUC to comment, by January 25, 2019. On January 30, 2019, the court found that the Utility had violated a condition of its probation with respect to reporting requirements related to the 2017 Honey fire. The court issued an order stating that a sentencing hearing on the probation violation will be set at a later date. The court also invited parties to comment by February 20, 2019, on the 2019 Wildfire Safety Plan that the Utility submitted to the CPUC on February 6, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				2,433,257
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				520,640
3	Preceding Quarter/Year to Date Changes in Fair Value				3,336,770
4	Total (lines 2 and 3)				3,857,410
5	Balance of Account 219 at End of Preceding Quarter/Year				6,290,667
6	Balance of Account 219 at Beginning of Current Year				6,290,667
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(1,479,837)
8	Current Quarter/Year to Date Changes in Fair Value				(5,797,538)
9	Total (lines 7 and 8)				(7,277,375)
10	Balance of Account 219 at End of Current Quarter/Year				(986,708)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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			2,433,257		
2			520,640		
3			3,336,770		
4			3,857,410	1,691,270,758	1,695,128,168
5			6,290,667		
6			6,290,667		
7			(1,479,837)		
8			(5,797,538)		
9			(7,277,375)	(6,818,107,469)	(6,825,384,844)
10			(986,708)		

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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)	74,125,476,600	54,086,032,049
4	Property Under Capital Leases	18,230,721	
5	Plant Purchased or Sold	-175,153	5,412
6	Completed Construction not Classified	12,823,811,035	7,129,231,035
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	86,967,343,203	61,215,268,496
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,562,027,669	1,720,845,397
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	89,529,370,872	62,936,113,893
14	Accum Prov for Depr, Amort, & Depl	37,353,599,037	26,907,643,431
15	Net Utility Plant (13 less 14)	52,175,771,835	36,028,470,462
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	36,332,965,571	26,845,549,665
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	8,525,339	
21	Amort of Other Utility Plant	1,012,108,127	62,093,766
22	Total In Service (18 thru 21)	37,353,599,037	26,907,643,431
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	37,353,599,037	26,907,643,431

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
13,916,406,240				6,123,038,311	3
				18,230,721	4
-180,565					5
5,175,470,140				519,109,860	6
					7
19,091,695,815				6,660,378,892	8
					9
					10
352,902,795				488,279,477	11
					12
19,444,598,610				7,148,658,369	13
7,703,873,367				2,742,082,239	14
11,740,725,243				4,406,576,130	15
					16
					17
7,696,385,371				1,791,030,535	18
					19
8,525,339					20
-1,037,343				951,051,704	21
7,703,873,367				2,742,082,239	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
7,703,873,367				2,742,082,239	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	261,763,030	78,340,869
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	261,763,030	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	416,084,176	106,154,666
10	SUBTOTAL (Total 8 & 9)	416,084,176	
11	Spent Nuclear Fuel (120.4)	2,265,141,307	94,857,219
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,505,050,242	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	437,938,271	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
	106,154,666	233,949,233	3
			4
			5
		233,949,233	6
			7
			8
	94,857,220	427,381,622	9
		427,381,622	10
		2,359,998,526	11
			12
-125,886,537		2,630,936,779	13
		390,392,602	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 3 Column: e

Cost of fuel inserted into reactor during 2018; cost transferred from Nuclear Fuel in Process to Nuclear Fuel in Reactor.

Schedule Page: 202 Line No.: 9 Column: e

Cost of spent fuel transferred from Nuclear Fuel in Reactor to Spent Nuclear Fuel in 2018.

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	113,935,938	24,823,199
4	(303) Miscellaneous Intangible Plant	4,126,232	1,166,068
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	118,062,170	25,989,267
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,644,205	
9	(311) Structures and Improvements	113,561,273	109,771
10	(312) Boiler Plant Equipment	276,508,417	2,442,743
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	257,380,332	
13	(315) Accessory Electric Equipment	52,595,986	29,565
14	(316) Misc. Power Plant Equipment	28,348,904	
15	(317) Asset Retirement Costs for Steam Production	96,102,035	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	833,141,152	2,582,079
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	22,726,561	
19	(321) Structures and Improvements	1,085,772,994	6,835,729
20	(322) Reactor Plant Equipment	3,517,473,860	71,354,380
21	(323) Turbogenerator Units	1,170,599,139	7,411,227
22	(324) Accessory Electric Equipment	846,769,572	21,188,894
23	(325) Misc. Power Plant Equipment	1,147,664,525	41,690,752
24	(326) Asset Retirement Costs for Nuclear Production	2,272,616,627	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	10,063,623,278	148,480,982
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	42,302,196	409,562
28	(331) Structures and Improvements	499,373,873	29,748,058
29	(332) Reservoirs, Dams, and Waterways	2,079,068,411	40,774,259
30	(333) Water Wheels, Turbines, and Generators	954,260,058	68,183,816
31	(334) Accessory Electric Equipment	271,049,293	27,932,714
32	(335) Misc. Power PLant Equipment	94,926,142	8,559,531
33	(336) Roads, Railroads, and Bridges	85,007,646	8,146,421
34	(337) Asset Retirement Costs for Hydraulic Production	7,200,427	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	4,033,188,046	183,754,361
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,207,870	
38	(341) Structures and Improvements	210,604,019	200,429
39	(342) Fuel Holders, Products, and Accessories	11,271,196	
40	(343) Prime Movers	226,088,318	803,368
41	(344) Generators	353,681,235	197,027
42	(345) Accessory Electric Equipment	212,857,732	856,942
43	(346) Misc. Power Plant Equipment	97,457,928	1,188,085
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,131,168,298	3,245,851
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	16,061,120,774	338,063,273

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	276,608,506	684,064
49	(352) Structures and Improvements	461,242,771	34,815,270
50	(353) Station Equipment	6,170,545,480	481,497,306
51	(354) Towers and Fixtures	916,974,214	47,048,198
52	(355) Poles and Fixtures	1,174,526,222	211,430,662
53	(356) Overhead Conductors and Devices	1,535,926,474	184,432,168
54	(357) Underground Conduit	504,865,156	7,335,852
55	(358) Underground Conductors and Devices	272,635,262	1,728,574
56	(359) Roads and Trails	86,759,267	7,594,898
57	(359.1) Asset Retirement Costs for Transmission Plant	3,988,851	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	11,404,072,203	976,566,992
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	175,062,439	5,593,729
61	(361) Structures and Improvements	327,090,066	742,753
62	(362) Station Equipment	3,354,258,444	191,731,907
63	(363) Storage Battery Equipment	33,232,585	264,688
64	(364) Poles, Towers, and Fixtures	4,323,200,397	542,735,774
65	(365) Overhead Conductors and Devices	4,690,443,433	257,144,056
66	(366) Underground Conduit	2,861,362,449	142,249,470
67	(367) Underground Conductors and Devices	4,554,288,320	261,215,464
68	(368) Line Transformers	3,451,398,731	365,166,596
69	(369) Services	3,272,328,566	151,958,578
70	(370) Meters	1,157,714,458	55,069,449
71	(371) Installations on Customer Premises	27,313,912	756,690
72	(372) Leased Property on Customer Premises	895,448	
73	(373) Street Lighting and Signal Systems	231,835,835	22,931,564
74	(374) Asset Retirement Costs for Distribution Plant	15,233,800	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	28,475,658,883	1,997,560,718
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	424,632	
87	(390) Structures and Improvements	11,254,863	522,272
88	(391) Office Furniture and Equipment	15,628,644	215,865
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	129,933,249	15,424,364
92	(395) Laboratory Equipment	14,556,151	1,471,911
93	(396) Power Operated Equipment	271,024	
94	(397) Communication Equipment	291,009,027	77,704,741
95	(398) Miscellaneous Equipment	70,772,401	16,144,550
96	SUBTOTAL (Enter Total of lines 86 thru 95)	533,849,991	111,483,703
97	(399) Other Tangible Property	468,499,422	
98	(399.1) Asset Retirement Costs for General Plant	7,292,156	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,009,641,569	111,483,703
100	TOTAL (Accounts 101 and 106)	57,068,555,599	3,449,663,953
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)	219,416	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	57,068,336,183	3,449,663,953

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (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
			138,759,137		3
3,389			5,288,911		4
3,389			144,048,048		5
					6
					7
			8,644,205		8
			113,671,044		9
		-989,383	277,961,777		10
					11
			257,380,332		12
			52,625,551		13
			28,348,904		14
			96,102,035		15
		-989,383	834,733,848		16
					17
			22,726,561		18
3,353,723			1,089,255,000		19
10,522,065			3,578,306,175		20
3,261,577			1,174,748,789		21
66,467			867,891,999		22
25,947,697			1,163,407,580		23
	1,092,350,056		3,364,966,683		24
43,151,529	1,092,350,056		11,261,302,787		25
					26
8,974			42,702,784		27
3,410,063			525,711,868		28
1,296,654		4,728,569	2,123,274,585		29
10,722,940			1,011,720,934		30
2,865,660			296,116,347		31
1,063,343			102,422,330		32
17,742			93,136,325		33
			7,200,427		34
19,385,376		4,728,569	4,202,285,600		35
					36
			19,207,870		37
			210,804,448		38
			11,271,196		39
		989,383	227,881,069		40
			353,878,262		41
			213,714,674		42
			98,646,013		43
					44
		989,383	1,135,403,532		45
62,536,905	1,092,350,056	4,728,569	17,433,725,767		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,490			277,291,080		48
			496,058,041		49
41,550,592	-822,172		6,609,670,022		50
2,188,965			961,833,447		51
4,322,481			1,381,634,403		52
7,297,467			1,713,061,175		53
1,024,869			511,176,139		54
343,845			274,019,991		55
			94,354,165		56
	-2,354,516		1,634,335		57
56,729,709	-3,176,688		12,320,732,798		58
					59
5,329			180,650,839		60
254,994		-4,728,569	322,849,256		61
33,300,743	-125,567		3,512,564,041		62
			33,497,273		63
33,207,217			4,832,728,954		64
147,761,741			4,799,825,748		65
59,432			3,003,552,487		66
8,883,910			4,806,619,874		67
25,838,062			3,790,727,265		68
2,107,371			3,422,179,773		69
11,503,350			1,201,280,557		70
			28,070,602		71
			895,448		72
31,017			254,736,382		73
	-8,940,961		6,292,839		74
262,953,166	-9,066,528	-4,728,569	30,196,471,338		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			424,632		86
			11,777,135		87
414,288			15,430,221		88
					89
					90
			145,357,613		91
121,553			15,906,509		92
271,024					93
463,072			368,250,696		94
1,510,994	1,694,626		87,100,583		95
2,780,931	1,694,626		644,247,389		96
			468,499,422		97
	246,166		7,538,322		98
2,780,931	1,940,792		1,120,285,133		99
385,004,100	1,082,047,632		61,215,263,084		100
					101
	-224,828		-5,412		102
					103
385,004,100	1,082,272,460		61,215,268,496		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	NONE			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	NONE			
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74001039 SAN FRAN Y (LARKIN): REPLACE 12KV SWGR	47,860,661
2	7054908 MC-P Relic- Project Management	38,252,003
3	68011748 PLO-U2:Repl Main Generator Stator	37,302,124
4	74000916 KERN PP: UPGRADE 230 KV BUS	34,011,822
5	74015944 EMBARCADERO (SF-Z) DECOUPLE BKS 1, 3, 5	24,225,606
6	7070913 DS conduct Rel studies	23,593,525
7	74001857 EL CERRITO G: 115KV BUS UPGRADE PHASE 1	22,076,849
8	74004821 VACA DIXON: REP 500 KV SERIES CAP BK 2	20,143,416
9	74000600 FULTON-FITCH MTN. RECOND 60KV LN	16,298,171
10	7021725 UNFFR Relic Routine Project Management	16,293,482
11	74000924 ESTRELLA_CPUC LIC/PER	15,863,538
12	74003442 MOSS LANDING: REPLACE 500 KV BREAKERS	14,111,604
13	74000925 MIDWAY ANDREW_CPUC LIC/PER	14,024,624
14	74001031 MIDWAY-KERN PP #2 230 KV LINE KERN AREA	13,946,561
15	74002444 GATES: REPL BK 500/230 KV TRANSFORMER	13,843,748
16	74002376 BORDEN 230 KV VOLTAGE SUPPORT (SUB)	13,574,688
17	74002462 PEASE - 115KV BUS TO BAAH RECONFIG	13,493,496
18	7026033 UNFFR Relic Aquatic Resource Stdy	12,909,427
19	74000841 HERNDON-KEARNEY 230 KV LINE RECONDUCTOR	12,236,016
20	13004820 Drum Spaulding - Developing PAD and NOI	12,088,194
21	74002892 VACA DIXON: REP 500 KV SERIES CAP BK 1	11,980,879
22	74000846 METCALF - EVERGREEN RECONDUCTORING (TL)	11,662,602
23	74001780 RIO OSO: INSTALL 230KV BAAH/GIS	11,614,759
24	74001097 COOLEY LANDING: INSTALL BK 2	11,606,728
25	74001782 RIO OSO: INSTALL 115 KV BAAH/GIS	11,559,275
26	74000662 VALLEJO B: REPLACE 4KV SWGR & BANKS	11,532,821
27	74001858 EL CERRITO G: REPL 12KV CBS W/SWGR	11,304,634
28	74001957 MONTA VISTA: UPGRADE 230 KV BUS - PH 1	11,289,147
29	74003144 BELLOTA: INSTALL 230 KV SHUNT REACTOR	11,272,940
30	74000939 WRJ NONCOMPETITIVE_CPUC LIC/PER	10,818,407
31	74001389 SMYRNA-SEMITROP-MIDWAY 115KV NERC ALERT	10,453,243
32	74001953 SAN FRAN F (MARINA): REPLACE 4KV SWGR	10,098,274
33	74003358 PIT PH 1: ADD BK 5	9,844,074
34	74011380 74011380_GREATER BAY ER STORAGE FAC SF	9,786,344
35	74000901 MARTIN BUS EXTENSION_CPUC LIC/PER	9,773,092
36	74002346 MARYSVILLE SUB: CONVERT TO RING BUS	9,559,341
37	74011760 NETWORK SCADA Y-2	9,381,992
38	68053001 COM: Integrated Video Mgt System Upgrade	9,324,636
39	74001398 60-SOUTH OF PALERMO REINFORCEMENT (PH-3)	9,058,695
40	74007941 CALTRAIN INTERCONNECTIONS SUB SITE 3	9,055,298
41	74001223 REDWOOD CITY: REP CB404,406,408,409,410	9,012,860
42	74001396 60-SOUTH OF PALERMO REINFORCEMENT (PH-2)	8,974,429
43	TOTAL	1,720,845,397

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	74000988 CASTRO VALLEY: REPLACE 12 KV SWITCHGEAR	8,788,097
2	74010530 74010530 GREATER BAY ER STORAGE FAC OAK	8,566,174
3	13003982 DS-C Relic- Cond studies for all RA	8,517,659
4	74001785 RIO OSO: INSTALL 230 KV MPAC	8,379,509
5	74001942 KERN PP 230KV MPAC	8,334,198
6	74000933 230 KV TLINE LOCKEFORD - NEW INDUSTRIAL	8,252,391
7	74001588 ORO LOMA: INSTALL 115 KV MPAC	8,203,725
8	74000981 HERNDON SUB - NORTHERN FRESNO 115KV AREA	8,201,914
9	74006580 NV_TESLA 230KV BUS DIFFERENTIAL REPLACE	7,869,354
10	74000714 (DA-CE) COLGATE-CHALLENGE RELIABILITY	7,793,112
11	7076869 Buck Rel Studies	7,549,005
12	74001786 RIO OSO: INSTALL 115 KV MPAC	7,510,911
13	74000959 MCCALL SUB - NORTHERN FRESNO 115KV AREA	7,369,704
14	74001710 SANGER: REPLACE 115 KV BUS	7,325,398
15	74000343 CALTRAIN INTERCONNECTIONS SUB SITE 1	7,142,520
16	74001391 60-SOUTH OF PALERMO REINFORCEMENT (PH-1)	6,973,678
17	74001620 Pit 3 Unit 3 Replace Rewind	6,892,123
18	74015243 TSRP-NORTH BAY SIERRA PROJECT MANAGEMENT	6,823,920
19	74009262 KASSON SUB: REPLACE BANK 1	6,221,577
20	7026032 UNFFR Relic Water Use & Qlty Stdy	6,197,315
21	74001708 SANGER: INSTALL 115 KV MPAC	6,197,049
22	74001781 RIO OSO: INSTALL BK 1 AND BK 2	6,180,150
23	74001112 RIPON NEW 115 KV LINE 2ND TAP RELIABILIT	6,097,982
24	74001713 HUNTERS POINT: 115KV GIS BAAH	6,085,776
25	7026037 UNFFR Relic Land Use/Mgt Study	5,936,003
26	74004964 SOBRANTE: ADD & REPL 14-115KV BKERS P2	5,867,022
27	7055507 DS Relic- Strategic Planning	5,736,990
28	7055646 DS Relic- Project Management	5,702,054
29	68017320 PLO-Remove Abandoned in place RO System	5,639,241
30	74003025 IGNACIO: INSTALL 230 KV SHUNT REACTOR	5,622,270
31	74001063 GATE-GREGG 230KV T-LINE CPUC LIC/PER	5,602,736
32	74016300 NETWORK SCADA Y-1	5,523,955
33	74010662 Helms - Main Crane Modification	5,416,072
34	74004615 EAGLE ROCK-FULTON-SILVERADO NERC PROJECT	5,273,864
35	74001960 MOSS LANDING: INST 500 KV CTRL BUILDING	5,229,936
36	74001853 EL CERRITO G:REPLBK4 W/BK3 115-12KV 60MV	5,039,026
37	74010941 BORDEN: INSTALL MPAC	4,980,717
38	7089447 Potter Valley Rel Studies	4,865,138
39	74003359 MARTIN: REPLACE 230 KV SHUNT REACTOR 1	4,818,696
40	7072819 Helms - Replace Liquid Rheostat	4,775,041
41	74002483 SPENCE: INSTALL BK 1	4,523,667
42	74002743 STOCKTON A WEBER	4,508,263
43	TOTAL	1,720,845,397

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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	74014700 Pit 6 U1 Replace Transformer	4,477,671
2	74009948 BELLOTA SUB: PHYSICAL SECURITY UPGRADE	4,386,447
3	68015242 PLO-COM::Rplc Secondary Chem Lab	4,310,063
4	74001472 GOLD HILL: REPLACE CB 222 242 252 212	4,300,964
5	74001436 (DA-B&M) ELECTRA-VALLEY SPRGS CAP/RECOND	4,285,069
6	74001723 PEASE - INST BANK 5	4,285,039
7	74000626 CAMANCHE TAP 115KV RECONDUCTOR	4,210,824
8	74005663 KERN PP: CONVERT 115KV BUS TO BAAH	4,102,854
9	74008620 Fordyce Dam Leakage Reduction	4,045,838
10	74006762 METCALF-SALINAS NO. 1 (IDLE) (P3)	3,914,960
11	74009504 SF M SUB, REPLACE BK 1 12KV & 4KV SWGR	3,902,068
12	74004832 WEEDPATCH 70 KV CB 42 52 62	3,888,438
13	68049386 PLO-COM: Reloc Security VIS	3,887,443
14	74001001 WHEELER RIDGE-WEEDPATCH 70 KV (KALTR)	3,867,833
15	68020200 PLO: U2: REPL CFCU CLNG COILS (2R21)2-5	3,861,388
16	74002247 ORO LOMA: REPLACE BK 2 115/70 KV	3,805,760
17	74020222 FULTON-CALISTOGA 60 KV LINE RECONDUCTORE	3,745,737
18	74000709 (DA-TRC) HUMBOLDT BAY RECOND. PROJ. 2021	3,719,903
19	74018125 SPENCE: UPGRADE TRANSMISSION 60 KV	3,695,509
20	74002930 COLUMBUS: INSTALL 2-115 KV CBS	3,682,051
21	74001175 MOSHER-LOCKFORD 60KV RECOND.	3,666,256
22	74004265 ORO LOMA: INSTALL BK 3	3,639,894
23	74011616 Helms - Rewind U2	3,637,902
24	74009760 TC Canal_Install Canal Liner 17/19	3,516,447
25	74000825 LEMOORE NAS 70 KV SCADA SW#55,65	3,397,631
26	74004888 OAKLAND D SUB: REPLACE 4KV SWITCHGEAR	3,365,135
27	74000711 NRS-SCOTT RECONDUCTORING	3,340,931
28	74001688 NC_(DA-ABB) MAPLE CREEK SUB:REACTIVE SUP	3,336,884
29	68019301 U1:Upgrade Polisher Computer Workstation	3,322,543
30	30797619 OAKLEY GENERATING STN: LAS POSITAS-NEWAR	3,305,177
31	74001432 COTTNWD-RED BLUFF - RECONDUCTOR	3,291,424
32	7049829 DC Relic Begin Prep of NOI and PAD	3,253,857
33	7026034 UNFFR Relic Terres Resources Stdy	3,250,247
34	74001453 Electra U3 New Needle, Stem & Bushings	3,244,265
35	74018362 FLINT SUB: EMER BK1 REPLACE	3,227,687
36	74004617 GEYSERS #9-LAKEVILLE NERC PROJECT	3,165,208
37	74002214 HOPLAND: REPLACE BK 2	3,119,450
38	74001179 NV_94-INDIAN FLAT SUB:REPL SW 17 W/1-70K	3,113,452
39	13006140 MC-P Relic- Conduct Relicensing Studies	3,089,012
40	74006763 METCALF-SALINAS NO. 2	3,030,268
41	74000700 TEMPLETON 230/70KV MPAC	3,022,647
42	74005020 MIDWAY: UPGRADE 230 KV BUS SECTION D	2,989,401
43	TOTAL	1,720,845,397

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	31168794 ETTM RANCHO VISTA MHP	2,959,277
2	7053945 DC Relic - Prepare Study Plans	2,939,134
3	74005023 SHAFTER SUBSTATION: BANK 1	2,938,687
4	74000731 EAST SHORE-OAKLAND J 115KV RECONDUCT(TL)	2,938,111
5	7054909 MC-P Relic- Prepare NOI and PAD	2,908,006
6	74001200 EXCHEQUER SUB TO BEAR VALLEY SUB	2,854,654
7	74001427 WEBER-SANTA FE JUNCTION 60 KV RECON	2,835,960
8	74011148 VACA DIXON: EM INSTALL STATION LIGHTING	2,782,683
9	74008580 ASHLAN: CONVERT TO 230 KV RING BUS	2,779,535
10	74005670 VALLEJO B: REPLACE 4 KV SWGR - DLINE	2,769,754
11	74004826 67-HICKS: INSTALL 230KV MPAC (CONSTR 201	2,764,927
12	74009861 BRUCE RD CHICO R20A	2,762,560
13	74001022 LERDO: REPLACE 12 KV BUS SECTION E	2,760,452
14	68044182 PLO: COM: REPL HVAC Units 501, 502, 503	2,739,325
15	74021024 MORGAN HILL SUB: 115KV BAAH CONVERSION	2,736,161
16	13008740 Battle Crk - Phase 2 License Amendment	2,732,217
17	7076872 Buck Rel Lic App	2,732,140
18	74000915 KERN 230KV AREA REIN MIDWAY-KERN 3 & 4 (	2,705,944
19	74001642 R1 MIDDLEFIELD ROAD REDWOOD CITY R20A	2,693,039
20	74015245 TSRP-NORTH BAY SIERRA ET COMM- READY SUB	2,688,328
21	13011921 NFSL Additional Design Imp	2,688,213
22	7043247 RCC Lic Imp Cold Water Feasibility Study	2,687,809
23	74001856 EL CERRITO G: 115KV BUS UPGRADE PHASE 2	2,684,935
24	74008161 2018 CARUTHERS 1102 EXTEND & REINF PH. 2	2,674,750
25	68009762 PLO-U2:Replace DG22 Exciter/Voltage Regu	2,669,044
26	74008366 MESA SUB VOLTAGE SUPPORT	2,665,296
27	74000601 FULTON-FITCH: RECONDUCTORING 60 KV	2,663,947
28	7021727 UNFFR Relic Prepare 5 Year Library	2,604,684
29	74002486 KERN PP: INSTALL 115KV MPAC BLDGS	2,597,583
30	74000936 WRJ COMPETITIVE_CPUC LIC/PER	2,577,508
31	74007560 EMBARCADERO - REPLACE 34/12KV BANK 12	2,561,630
32	74000546 KEARNEY-CARUTHERS 70 KV LINE RECONDUCTOR	2,561,447
33	30854865 NEWARK-AMES 1300FT BW 46-50 CRITTENDON	2,550,149
34	74001766 RAVENSWOOD-COOLEY LANDING 115 KV (TL)	2,532,159
35	7093246 ODN Network Segmentation	2,517,120
36	74021027 METCALF-GREEN VALLEY 115KV: LINE RECONDU	2,474,875
37	74003441 ASHLAN: INSTALL MPAC BUILDING & OPGW	2,472,488
38	74018601 GATES-TULARE LAKE 70KV EMERGENCY WORK	2,454,647
39	68019124 PLO-Com:Repl Breathing Air Compsr Ph II	2,452,174
40	13002402 DS-C Relic- Conduct Pre-App Proj Man	2,446,314
41	68000146 Lead Order-U2:Repl Boric Acid Xfer Pumps	2,443,385
42	13011869 Pit 6 Replace Stoplog Lifting Device	2,437,234
43	TOTAL	1,720,845,397

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74001334 TEMBLOR-SAN LUIS OBISPO 115KV NERC	2,430,238
2	30842587 OAKLEY GENERATING STN:COCOPP-DELTA PUMPS	2,423,395
3	74000345 CHSR INTERCONNECTIONS SUB SITES 4-7	2,383,891
4	7026036 UNFFR Relic Rec Resources Study	2,361,923
5	31214160 EM_RICHMOND Q SUB - REPL. UNIT SUBS	2,359,578
6	74001677 NV_STOCKTON A SUB- REPLACE CB 402,404	2,354,542
7	74006884 MORRO BAY SUB: UPGRADE 230KV BUS	2,345,835
8	68019302 PLO-U2:Cond. Polisher Cmptr Upgrade	2,304,229
9	74001064 GATES-GREGG PRE-BID COSTS	2,290,371
10	74000900 Bucks Creek U2 Generator Rewind	2,288,512
11	74018460 RMR: TRIMBLE-SAN JOSE B 115KV SERIES REA	2,286,635
12	68036981 PLO: COM: 500kv Road Upgrade	2,274,196
13	68050741 PLO-U1: Repl DRPI Detector/Encoder Cards	2,253,910
14	31298384 ODN SECURITY PROJECT	2,236,884
15	74000707 60 KINGSBURG-LEMOORE 70KV RECOND. PH1	2,225,234
16	74008419 Caribou 1 Crane Modernization	2,224,924
17	74001173 LODI: REPLACE CB 12 22 32	2,190,937
18	74005121 EVERGREEN SUB: 115KV BUS UPGRADE	2,190,606
19	74000341 CHSR INTERCONNECTIONS SUB SITES 8-13	2,188,887
20	74001732 VIERRA 115 KV REINFORCEMENT (T-LINE)	2,188,471
21	74007808 RICE SUB: REPLACE BANK 1	2,174,438
22	68048860 PLO - U1: Repl Plant Recorders	2,165,077
23	74008380 Cresta PH Refurbish Transformers	2,164,619
24	74008281 Bucks Cr Replace Turb Brg / Shaft	2,147,649
25	74004825 HICKS: IMPROVE 230 KV BUS RELIABILITY	2,114,460
26	13011870 Pit 7 Replace Stoplog Lifting Device	2,103,301
27	74001020 SHAFTER SUB-REPLACE CB 1101, 1102, 1103	2,093,449
28	74006361 DELEVAN: INSTALL 200 MVAR SHUNT REACTOR	2,087,161
29	74008660 2018 GATES 1110 12KV FEEDER	2,075,286
30	74001047 KERN 230KV AREA REIN MIDWAY-KERN 1 & 2 (	2,074,734
31	13009580 DeSabla Replace Governor	2,072,742
32	74015582 STUART: EM REPLACE 12/4 KV BK1	2,066,581
33	74005355 RIO OSO SUB: SVC	2,054,284
34	74008455 Cresta PH Arc Flash Remediation U1&U2	2,042,601
35	74000840 -ENG.ONLY (DA-B&M) KESWICK-TRINITY REL.	1,997,723
36	74002485 NC_PUEBLO SUB: REPLACE BK 1	1,991,741
37	74015805 LERDO: REPLACE 12 KV BUS SECTION	1,970,734
38	7026029 UNFFR Relic Prep 1st Stage Consult Pkg	1,962,278
39	74010660 Balch 2 - U2 Replace Cooling Water	1,959,326
40	68038260 PLO-COM: North Access Rd Upgrade	1,947,546
41	74001739 (CONT.EST) MAPLE CREEK-WILLOW 60KV REL.	1,944,682
42	74008524 EP BRIDGE ST COLUSA R20A	1,936,386
43	TOTAL	1,720,845,397

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74010750 MONTA VISTA: INSTALL 230KV MPAC	1,932,577
2	74001553 EP SHELL BEACH RD PISMO BEACH R20A	1,927,008
3	74012040 NICOLAUS-WILKINS SLOUGH 60KV LINE POLE	1,919,578
4	74017519 VACA DIXON: INSTALL 230 KV SMART WIRES	1,919,282
5	74011030 KERN 230KV BAAH 115KV LINE RELOCATION	1,917,488
6	7092705 Asset Data Improvement (GIS Phasing-Sub)	1,916,059
7	68021733 PLO-U1:Replace DG 1-2 Controls System	1,916,040
8	74003803 Q954 FIFTH STANDARD SOLAR (NU) GATES	1,915,635
9	74002410 Pit 5 TGB Install Inline Oil Filtration	1,901,496
10	74008358 SAN LEANDRO U: REPLACE CB 182, 372, 382	1,897,243
11	74002321 Inskip Eagle Canyon Access Safety Improv	1,895,135
12	74001792 RED BLUFF-COLEMAN REINFORCEMENT	1,894,567
13	74010413 BORDEN VOLTAGE SUPPORT - STOREY SUB	1,881,696
14	74008456 Cresta PH Repl Stoplog Hoist	1,846,138
15	7093006 WSOC (Ramp for addl functionality)	1,846,115
16	74003903 SHEPHERD 2111 AUBERRY ROAD RECON - 2018	1,820,443
17	74016583 Electra U2 Generator Rewind	1,818,114
18	74008384 Battle Cr Salmon/Steelhead Phase 2	1,810,645
19	74001704 FIREBAUGH: INSTALL 70 KV SCADA SWITCH	1,787,843
20	74004819 COTTLE: INSTALL 2 17 KV FEEDERS	1,770,652
21	68044188 PLO: COM: Upgrd Bldg 104 Entire 5th Flr	1,761,792
22	74016341 TSRP NBS IT OTHER SITES	1,760,829
23	13023101 Butte Head Dam Road Improvements 2017	1,702,945
24	74011488 VALLEYSPRINGS-MARTELL NO.2 SCADA	1,701,544
25	74005120 EVERGREEN: UPGRADE 60 KV PROTECTION	1,657,793
26	74009204 TABLE MTN:REPL 500KV TM-ROUND MTN #1 REL	1,651,955
27	74001943 WHEELER RIDGE VOLTAGE SUPPORT (SUB)	1,626,733
28	7062249 MC-P- Proj Scoping and Study Plan Devp	1,623,336
29	7070917 DS Post App filing activities	1,620,566
30	7087874 Permit Holdover Project - Shasta-Trinity	1,579,866
31	74001735 POTRERO-MISSION #1 (A-X 1) SEISMIC RETRO	1,574,099
32	74002189 FRENCH GULCH: INSTALL D-SCADA	1,573,970
33	74016584 Tiger Creek U2 Generator Rewind	1,573,569
34	74008849 CYMRIC: INSTALL MRTU	1,573,184
35	74003501 SUMMIT: REPL 60 KV SW 37 & SW OPERATOR	1,550,888
36	74009567 HERNDON: EM REPLACE CIRCUIT BREAKER 242	1,542,679
37	68035784 PLO-U2: Rewind RCP Stator S1	1,532,679
38	74000937 MERCY SPRINGS - CANAL SS T-LINE RECONDUC	1,531,312
39	74001584 STOCKTON A: REPLACE CONTROL BUILDING	1,524,445
40	74008301 Lower Bucks Dam Resurface Face	1,522,282
41	74010323 Poe PH Deck/Roof Resurface	1,505,083
42	74003484 WILSON: INSTALL STATCOM	1,504,758
43	TOTAL	1,720,845,397

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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	74015248 TSRP NBS IT NEW MPLS	1,503,871
2	74020280 OAKLAND K: EM_REPLACE ALS RTU	1,496,104
3	74009588 Pit 7 U2 Rewind	1,493,738
4	74001397 (DA-TRC)ESSEX JCT ORICK 60KV RELIABILITY	1,488,818
5	74000622 BELLOTA - WARNERVILLE RECONDUCTOR	1,485,149
6	74000505 MARTIN: 230KV BUS RETROFIT	1,472,849
7	74007647 PEASE - TLINE SUPPORT	1,470,458
8	74001098 TABLE MOUNTAIN: REPLACE 500 KV BK 1	1,470,212
9	74018320 RMR: MTN VIEW-WHISMAN-AMES PROJECT (AMES	1,466,319
10	13002403 DS-C Relic- Conduct Studies	1,465,011
11	7055645 DS Relic- Coord Study w/ NID	1,457,743
12	74001579 OAKLAND L: CUTOVER 4 KV TO 12 KV	1,449,832
13	35047949 Z-1113 CIRCUIT RECONDUCTOR	1,447,405
14	74010363 KERN PP - LIVE OAK 115KV PROJECT	1,446,453
15	74001733 POTRERO-LARKIN #2 (A-Y2) SEISMIC RETROFI	1,437,707
16	74001734 MARTIN-LARKIN #1 115 KV CABLE (H-Y 1)	1,437,233
17	74009587 Pit 1 U1 Rewind Generator	1,436,015
18	74001855 EL CERRITO G: 115KV BUS UPGRADE T-LINE	1,428,078
19	68021224 PLO- U1:Replace AFW Chem Inj Pmp	1,421,077
20	74009061 WESTPARK: INSTALL MPAC BUILDING	1,416,659
21	74008750 HP-3 GROUNDING PROJECT	1,411,402
22	74001802 PIT PH 1: REPLACE 230 KV BK 1	1,411,046
23	74003261 Caribou 1 U1 Rewind	1,410,606
24	74014522 ORO LOMA: UPGRADE 70 KV BUS	1,408,897
25	7093170 Wildfire Wire Down detection	1,398,790
26	7049828 DC Relic Project Management	1,394,967
27	31155972 OSM EBOSS COFUNDING	1,390,463
28	74004618 SILVERADO-FULTON JCT 115KV NERC	1,384,455
29	74008009 WILSON-LEGRAND 115KV LINE RECON TL - DO	1,383,073
30	74015260 CASCADE: INSTALL BK 2 PHASE 1	1,381,063
31	74011982 MISSION BLVD DIST 30 HAYWARD R20A	1,380,843
32	74001686 NC_MAPLE CREEK PROJ-BUS RECONFIGURATION	1,369,960
33	13006781 DeSabla-Centerville Proj Mgmt Post LA	1,353,139
34	74003600 Helms Replace Load Center 1, 2, 7 & 8	1,331,654
35	7089886 Kerckhoff Rel PAD and NOI	1,320,555
36	74011243 IGNACIO-MARE ISL 115KV (HWY SUB/COR SUB)	1,301,384
37	74002796 COCO: REPLACE D-SCADA	1,290,923
38	74015249 TSRP-NORTH BAY SIERRA ET MPAC/HMI SUBSTA	1,278,712
39	74009901 Rock Cr PH U1 & U2 Repl WG Seals	1,248,879
40	74010362 PILOT: SAN BRUNO INT PIPE-TYPE UG CABLE	1,232,203
41	74015247 TSRP-NORTH BAY SIERRA ET NEW COMM SYSTEM	1,231,725
42	74001486 GRIZZLY PEAK BLVD BERKELEY R20A	1,223,680
43	TOTAL	1,720,845,397

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74006664 RICE: EM REPLACE UNIT SUB 2	1,217,800
2	74010464 OLIVE SW STA-SMYRNA 115KV MAINTENANCE RE	1,201,884
3	74009501 Tiger Crk Abay LLO Gate Replace	1,197,997
4	74008922 VACA-TULUCAY-LAKEVILLE 230KV-NERC	1,196,386
5	74002547 Kings River PH - Replace Governor	1,188,342
6	74008421 Bucks Cr Modify 2 Cranes	1,180,523
7	74003069 LOS ESTEROS SHUNT REACTOR PROJECT	1,178,722
8	74003661 Bucks Creek U1 Generator Stator Rewind	1,178,121
9	74002167 HYAMPOM JCT: INSTALL T-SCADA CB 62	1,172,437
10	74001089 STOCKDALE 230 KV TAP #1 AND #2 FROM THE	1,169,293
11	31168741 ETTM MOREHEAD PARK	1,166,730
12	74004481 +MESA 1104 FEEDER - PHASE 1	1,161,207
13	74007445 Q1036 MUSTANG 2 (NU) 230 KV SS	1,154,391
14	74004508 LAKEWOOD SUB: REPLACE BANK 5	1,154,272
15	74001392 SOUTH OF PALERMO - PALERMO SUB	1,147,870
16	74002206 GLENN: REPLACE BK 1	1,147,214
17	74000665 BRIGHTON-GRAND ISLAND #1 & #2 115KV NERC	1,139,328
18	74008385 Coleman Decommission Asbury Pipe	1,136,821
19	74000733 CARIBOU-BIG BEND 115KV NERC	1,136,383
20	74014400 ASHLAN: REROUTE 230KV T-LINES	1,121,417
21	7093366 Dist Resources Planning Tools MA	1,114,320
22	7076871 Buck Rel Draft Lic App	1,113,730
23	74007447 PANOCHE-ORO LOMA 115 KV LINE RECONDUCTOR	1,108,160
24	74003620 Cresta PH Repl Tailrace Gates	1,102,409
25	74002545 Kings River - Repl Exciter	1,097,417
26	74009027 POTRERO: REPLACE SVC CONTROLLER	1,089,778
27	74003560 SKAGGS ISLAND: REM SUB	1,085,831
28	68045340 PLO: COM:ACCESS RD COMMUNICATIONS	1,081,955
29	74002818 KIRKER: INSTALL D-SCADA 2200	1,078,043
30	74003761 Rock Cr PH Repl Tailrace Gates	1,076,103
31	31234874 RELIAIBLITY 2017 - UWF VARIOUS CKTS	1,074,933
32	74004443 PITTSBURG: REPLACE CB 352 362	1,069,212
33	74002965 OAKLAND X: UPGD 115KV DIFF EDRS#: 201	1,068,652
34	74008666 EL CERRITO G: INST 12KV FDR OUTLET, PH 1	1,064,661
35	74010465 SMYRNA-SEMITROPIC-MIDWAY 115KV MAINTENAN	1,042,962
36	74001560 OAKLAND L: INSTALL 406, 407 CUTOVER 4KV	1,041,777
37	74010343 MARTIN: REPLACE 4KV SWITCHGEAR	1,041,281
38	74008383 Coleman Tailrace Barrier Trashrake	1,034,131
39	74009203 ROUND MTN: REPL 500KV RM-TAB MTN #1 REL	1,029,901
40	30978746 MUNI CENTRAL SUBWAY-CHINA TOWN STATI	1,029,226
41	74015486 ESTRELLA CPUC DATA REQUEST #3	1,028,982
42	74002176 CRESCENT MILLS: INSTALL D-SCADA CB210	1,012,873
43	TOTAL	1,720,845,397

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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	See footnote for detail.	268,814,896
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43	TOTAL	1,720,845,397

Schedule Page: 216.8 Line No.: 1 Column: b

This is the aggregate total of projects with less than $1,000,000 in actual costs in Construction Work in Progress, including credits representing preliminary billings.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	25,630,993,906	25,630,993,906		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	2,121,424,880	2,121,424,880		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Reverse Common Allocation	-149,778,194	-149,778,194		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,971,646,686	1,971,646,686		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	385,000,708	385,000,708		
13	Cost of Removal	292,499,258	292,499,258		
14	Salvage (Credit)	8,843,414	8,843,414		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	668,656,552	668,656,552		
16	Other Debit or Cr. Items (Describe, details in footnote):	-88,434,375	-88,434,375		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	26,845,549,665	26,845,549,665		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	309,485,888	309,485,888		
21	Nuclear Production	6,706,852,865	6,706,852,865		
22	Hydraulic Production-Conventional	1,403,250,911	1,403,250,911		
23	Hydraulic Production-Pumped Storage	774,777,368	774,777,368		
24	Other Production	329,161,699	329,161,699		
25	Transmission	3,155,263,008	3,155,263,008		
26	Distribution	13,577,519,257	13,577,519,257		
27	Regional Transmission and Market Operation				
28	General	589,238,669	589,238,669		
29	TOTAL (Enter Total of lines 20 thru 28)	26,845,549,665	26,845,549,665		

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

This reconciles with the cost of plant retired shown on pages 204-207, column (d), as follows:

Book cost of Depreciable Plant Retired	385,000,708
Book cost of Amortizable Plant Retired	3,392
Total	385,004,100
Book cost of Plant Retired, pages 204-207, column (d)	385,004,100
Difference	0

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

Other Debit or Cr. Items (Describe):

FAS 143 Assets Depreciation (Nuclear & Fossil)	77,880,295
Decommissioning reclass to Regulatory Liability (Nuclear & Fossil)	(20,583,693)
FIN 47 Asset Depreciation (EDP, EHP, ETP, EGP)	(6,604,973)
Capital Lease Obligations	(141,012,099)
Mirant Adjustment	2,260,506
Gain/Loss	(379,294)
Reserve Adjustment	4,883
Total	(88,434,375)

Schedule Page: 219 Line No.: 25 Column: c

FAS 109 Gross-up on Diablo Canyon Power Plant Utility Asset I is included in General Plant.

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Eureka Energy Company			
2	Common Stock	1978		1,000
3	Additional Paid in Capital			3,741,892
4	Undistributed Earnings			22,796
5				
6	SUBTOTAL			3,765,688
7				
8	Natural Gas Corporation of California			
9	Common Stock	1954		100,000
10	Additional Paid in Capital			3,037,432
11	Undistributed Earnings			-3,137,432
12				
13	SUBTOTAL			
14				
15	Pacific Energy Fuels Company			
16	Common Stock	1989		10,000
17	Additional Paid in Capital			4,698,621
18	Undistributed Earnings			-4,700,407
19				
20	SUBTOTAL			8,214
21				
22	Standard Pacific Gas Line Incorporated			
23	Common Stock	1930-32		1,200
24	Additional Paid in Capital	1954		43,473,426
25	Undistributed Earnings			-27,145,494
26	Advances: Note	05/09/1988	DEMAND	1,127,868
27	Note	09/06/1988	DEMAND	2,580,000
28	Note	12/30/1988	DEMAND	8,712,308
29	Note	08/22/1989	DEMAND	2,880,000
30	Note	10/09/1990	DEMAND	4,200,000
31	Note	02/25/1992	DEMAND	3,300,000
32	Note	12/01/1993	DEMAND	1,518,000
33				
34	SUBTOTAL			40,647,308
35				
36	Midway Power LLC			
37	Additional Paid in Capital	2008		26,085,184
38	Undistributed Earnings			-21,646,507
39				
40	SUBTOTAL			4,438,677
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	48,859,887

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
		1,000		2
		3,734,531		3
-67,037		-44,241		4
				5
-67,037		3,691,290		6
				7
				8
		100,000		9
		3,037,432		10
		-3,137,432		11
				12
				13
				14
				15
		10,000		16
		4,890,952		17
72,346		-5,102,693		18
				19
72,346		-201,741		20
				21
				22
		1,200		23
		45,889,873		24
64,526		-28,055,130		25
		1,127,868		26
		2,580,000		27
		8,712,308		28
		2,880,000		29
		4,200,000		30
		3,300,000		31
		1,518,000		32
				33
64,526		42,154,119		34
				35
				36
		26,112,410		37
-27,226		-21,673,733		38
				39
-27,226		4,438,677		40
				41
42,609		50,082,345		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	1,375,066	1,566,341	ELECTRIC
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)	98,115,315	118,788,016	ALL
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	131,373,581	122,909,574	ALL
8	Transmission Plant (Estimated)	31,138,026	42,589,220	ALL
9	Distribution Plant (Estimated)	104,997,211	158,373,602	ALL
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	365,624,133	442,660,412	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			ALL
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	366,999,199	444,226,753	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	129,839.00		13,860.00	
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	Allowances Used	12.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	129,827.00		13,860.00	
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	199.00		199.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	199.00			
40	Balance-End of Year			199.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		17		
45	Gains		17		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
13,860.00		13,860.00		360,360.00		531,779.00		1
								2
								3
				13,860.00		13,860.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
						12.00		20
								21
								22
								23
								24
								25
								26
								27
								28
13,860.00		13,860.00		374,220.00		545,627.00		29
								30
								31
								32
								33
								34
								35
199.00		199.00		9,751.00		10,547.00		36
				398.00		398.00		37
								38
				199.00		398.00		39
199.00		199.00		9,950.00		10,547.00		40
								41
								42
								43
					5		22	44
					5		22	45
								46

Schedule Page: 228 Line No.: 29 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line item on page 110. Difference is due to approximately $395,755,701 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately $430,000 in alternative fuel vehicle credits.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

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

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	NONE					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Santa Cruz 115kV Reinforcement	3,683,889	63,333			3,620,556
22	10/4/2016 (03/2016 to 12/2075)					
23						
24	DCPP Relicensing	16,403,494	2,050,437			14,353,057
25	01/01/2018 (01/2018 to 12/2025)					
26						
27	DCPP Canceled Orders	50,835,492				50,835,492
28	01/01/2018 (Pending 2020 GRC)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	70,922,875	2,113,770			68,809,105

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	(See details in foot notes)	2,610,739	186	(2,353,572)	186
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	(See details in foot notes)	1,120,039	186	(2,034,585)	186
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 2 Column: a

Order	Order Description	Balance 12/31/17	Cost Incurred	Reimbursements received	Balance 12/31/18
9715072	WL -(SIS)Interconnection Merced Irr Dist			(500.00)	(500.00)
9719582	WG Gradient Resources Project SIS	22,883.99			22,883.99
9719800	WAPA O'Neill Substation - System Impact	4,623.39			4,623.39
9719900	WG - BURNS&MCDONNELL-Cluster work	5,991.03	(473.44)		5,517.59
9722202	WG - C6 - Cluster 6 Phase 2	24,433.62			24,433.62
9724040	KMPUD Load Interconnection Study	(11,807.00)			(11,807.00)
9724300	Ntwrk Eval for Calpine 115kV Geysers Gen	(10,369.32)			(10,369.32)
9725002	WG - C8 - SM - Quail Creek Solar 1	127.91			127.91
9725844	CDWR BDCP Phase 2 sudy	703.14			703.14
9726740	WG - 2016 Reassessment Gen Interconn	(0.68)			(0.68)
9726940	WAPA - Cottonwood Olinda line work	106,088.91			106,088.91
9727720	SFPUC - Potrero Interconnection	179.06			179.06
9727980	LBNL Capacity Increase	4,653.80			4,653.80
9728340	SVP Breaker Replacement	(8,863.39)			(8,863.39)
9728360	Travis AFB Facility Study	(64,155.75)			(64,155.75)
9728526	Port of Stockton Load Increase	(21,889.59)			(21,889.59)
9728645	WG # MMA # Q720&Q1002	(0.02)			(0.02)
9729040	2016 Merced ID Load Interconnection Faci	(19,503.75)		(19,503.75)	(39,007.50)
9729280	LBNL Interconnection Capacity Increase	23,582.69		(23,583.00)	(0.31)
9729340	WG - 2017 Reassessment	301,644.22		(301,644.00)	0.22
9729546	WAPA SLTP	3,043.50			3,043.50
9729703	WG - C9P2 - Cluster 9 Phase 2	789,183.38	36,814.01	(826,010.60)	(13.21)
9729761	Port of Stockton FAS	(40,364.18)			(40,364.18)
9729808	WG - Cluster IR Review/SM for Protection	(0.20)	5,158.61		5,158.41
9729841	WG - C10P1 - Cluster 10 Phase 1	519,231.36	267,217.07	(786,448.44)	(0.01)
9729845	WG - C10 - SM - Project01	(104.94)			(104.94)
9729846	WG - C10 - SM - Project02	(127.98)			(127.98)
9729847	WG - C10 - SM - Project03	(128.64)			(128.64)
9729848	WG - C10 - SM - Project04	(242.05)			(242.05)
9729849	WG - C10 - SM - Project05	(155.86)			(155.86)
9729850	WG - C10 - SM - Project06	(257.93)			(257.93)
9729851	WG - C10 - SM - Project07	(197.01)			(197.01)
9729852	WG - C10 - SM - Project08	(247.86)			(247.86)
9729853	WG - C10 - SM - Project09	(192.47)			(192.47)
9729854	WG - C10 - SM - Project10	(237.51)			(237.51)
9729855	WG - C10 - SM - Project11	5,426.86			5,426.86
9729856	WG - C10 - SM - Project12	(134.78)			(134.78)
9729857	WG - C10 - SM - Project13	(112.86)			(112.86)
9729859	WG - C10 - SM - Project15	(186.00)			(186.00)
9729881	WG - C10 - SM - Project17	(226.49)			(226.49)
9729882	WG - C10 - SM - Project18	(145.56)			(145.56)
9729883	WG - C10 - SM - Project19	(124.42)			(124.42)
9729884	WG - C10 - SM - Project20	(237.94)			(237.94)
9729885	WG - C10 - SM - Project21	(5,962.76)			(5,962.76)
9729886	WG - C10 - SM - Project22	(170.12)			(170.12)
9729887	WG - C10 - SM - Project23	(144.19)			(144.19)
9729888	WG - C10 - SM - Project24	(133.48)			(133.48)
9729889	WG - C10 - SM - Project25	(151.47)			(151.47)
9729890	WG - C10 - SM - Project26	(249.28)			(249.28)
9729891	WG - C10 - SM - Project27	(197.01)			(197.01)
9729892	WG - C10 - SM - Project28	(271.86)			(271.86)

9729893	WG - C10 - SM - Project29	(264.84)			(264.84)
9729894	WG - C10 - SM - Project30	(112.09)			(112.09)
9729895	WG - C10 - SM - Project31	(220.00)			(220.00)
9729896	WG - C10 - SM - Project32	(220.33)			(220.33)
9729897	WG - C10 - SM - Project33	(101.95)			(101.95)
9729898	WG - C10 - SM - Project34	(79.06)			(79.06)
9729899	WG - C10 - SM - Project35	(147.21)			(147.21)
9729900	WG - C10 - SM - Project36	(269.40)			(269.40)
9729901	WG - C10 - SM - Project37	(177.25)			(177.25)
9729902	WG - C10 - SM - Project38	(258.96)	1,680.00		1,421.04
9729903	WG - C10 - SM - Project39	(70.70)			(70.70)
9729904	WG - C10 - SM - Project40	(163.29)			(163.29)
9729905	WG - C10 - SM - Project41	(195.08)			(195.08)
9729906	WG - C10 - SM - Project42	(122.16)			(122.16)
9729907	WG - C10 - SM - Project43	(309.21)			(309.21)
9729908	WG - C10 - SM - Project44	(163.08)			(163.08)
9729909	WG - C10 - SM - Project45	(242.71)			(242.71)
9729910	WG - C10 - SM - Project46	(292.32)			(292.32)
9729911	WG - C10 - SM - Project47	(438.55)			(438.55)
9729912	WG - C10 - SM - Project48	(339.34)			(339.34)
9729913	WG - C10 - SM - Project49	(265.06)			(265.06)
9729914	WG - C10 - SM - Project50	(79.39)			(79.39)
9729960	WG - C10 - SM - Project51	(9.36)			(9.36)
9729961	WG - C10 - SM - Project52	(134.78)			(134.78)
9729962	WG - C10 - SM - Project53	(102.07)			(102.07)
9729963	CAISO ISP Panoche	2,875.63		(3,136.48)	(260.85)
9730243	SFPUC - Potrero Interconnection	(100,813.68)	2,399.32	100,813.60	2,399.24
9730361	SVP Breaker Replacement Facility Study	8,269.68		(8,269.68)	-
9730681	WG - ISP - Porthos		1,680.00		1,680.00
9730823	WAPA Lemoore NAS	8,738.92	11,027.90		19,766.82
9732360	WG # Cluster 11 Phase 1		742,359.93		742,359.93
9707780	CP-Martin 115/60 kV Upgrade Project	379.02	1,343.45		1,722.47
9713955	WL - Tesla Tracy 230kV Line 1 Reloc-FAS	13,215.50			13,215.50
9722206	Trans Bay Cable Quick Start Study	3,596.35	1,667.86		5,264.21
9717187	WL - CA HiSpeed Train Interconnect Study	26,847.97	8,299.32	(11,297.12)	23,850.17
9714755	WL - KMPUD-IFAS	63,553.10			63,553.10
9731302	Swan Lake Affected Sys. Study	11,470.57	70,774.74		82,245.31
9731780	WG - 2018 Reassessment		387,072.56		387,072.56
9732200	WG # ISP-South Belridge Expansion		27,452.87		27,452.87
9732401	WG - C11 - SM - Project 01		5,691.89	(5,754.78)	(62.89)
9732402	WG - C11 - SM - Project 02		7,889.17	(7,952.05)	(62.88)
9732404	WG - C11 - SM - Project 04		6,231.20	(4,294.01)	1,937.19
9732405	WG - C11 - SM - Project 05		7,762.29	(7,825.18)	(62.89)
9732406	WG - C11 - SM - Project 06		7,200.50	(7,263.39)	(62.89)
9732407	WG - C11 - SM - Project 07		5,711.86	(5,774.75)	(62.89)
9732408	WG - C11 - SM - Project 08		8,178.59	(8,602.78)	(424.19)
9732409	WG - C11 - SM - Project 09		4,202.96	(4,265.85)	(62.89)
9732410	WG - C11 - SM - Project 10		5,437.91	(5,500.81)	(62.90)
9732411	WG - C11 - SM - Project 11		7,048.98	(6,436.84)	612.14
9732412	WG - C11 - SM - Project 12		7,057.66	(5,120.55)	1,937.11
9732413	WG - C11 - SM - Project 13		8,273.24	(8,336.13)	(62.89)
9732414	WG - C11 - SM - Project 14		5,468.32	(5,531.21)	(62.89)
9732415	WG - C11 - SM - Project 15		5,019.49	(5,082.38)	(62.89)
9732416	WG - C11 - SM - Project 16		4,546.60	(4,609.49)	(62.89)
9732417	WG - C11 - SM - Project 17		4,099.84	(4,162.74)	(62.90)

9732418	WG - C11 - SM - Project 18		4,955.96	(4,974.65)	(18.69)
9732419	WG - C11 - SM - Project 19		4,690.86	(4,753.75)	(62.89)
9732420	WG - C11 - SM - Project 20		6,610.86	(6,673.75)	(62.89)
9732421	WG - C11 - SM - Project 21		5,122.96	(5,185.85)	(62.89)
9732422	WG - C11 - SM - Project 22		5,897.47	(5,960.36)	(62.89)
9732423	WG - C11 - SM - Project 23		4,250.08	(4,312.97)	(62.89)
9732424	WG - C11 - SM - Project 24		5,274.03	(5,336.92)	(62.89)
9732425	WG - C11 - SM - Project 25		5,870.92	(3,933.81)	1,937.11
9732426	WG - C11 - SM - Project 26		4,786.84	(5,030.36)	(243.52)
9732427	WG - C11 - SM - Project 27		3,434.70	(3,497.60)	(62.90)
9732428	WG - C11 - SM - Project 28		6,053.19	(6,116.08)	(62.89)
9732429	WG - C11 - SM - Project 29		4,847.87	(4,910.76)	(62.89)
9732430	WG - C11 - SM - Project 30		4,991.41	(5,054.30)	(62.89)
9732431	WG - C11 - SM - Project 31		9,373.22	(9,616.74)	(243.52)
9732432	WG - C11 - SM - Project 32		4,304.22	(4,367.11)	(62.89)
9732433	WG - C11 - SM - Project 33		4,111.53	(4,174.43)	(62.90)
9732434	WG - C11 - SM - Project 34		4,084.00	(4,146.89)	(62.89)
9732435	WG - C11 - SM - Project 35		5,656.58	(5,900.09)	(243.51)
9732436	WG - C11 - SM - Project 36		4,675.96	(4,738.85)	(62.89)
9732437	WG - C11 - SM - Project 37		6,976.77	(7,039.66)	(62.89)
9732438	WG - C11 - SM - Project 38		6,851.40	(6,914.29)	(62.89)
9732439	WG - C11 - SM - Project 39		7,411.34	(7,474.23)	(62.89)
9732440	WG - C11 - SM - Project 40		5,254.08	(5,317.86)	(63.78)
9732441	WG - C11 - SM - Project 41		5,989.28	(5,292.87)	696.41
9732442	WG - C11 - SM - Project 42		7,262.53	(7,325.42)	(62.89)
9732443	WG - C11 - SM - Project 43		5,624.61	(5,687.49)	(62.88)
9732444	WG - C11 - SM - Project 44		6,546.73	(6,609.62)	(62.89)
9732445	WG - C11 - SM - Project 45		6,783.25	(4,846.14)	1,937.11
9732447	WG - C11 - SM - Project 47		4,935.89	(4,785.48)	150.41
9732448	WG - C11 - SM - Project 48		5,649.91	(4,712.80)	937.11
9732449	WG - C11 - SM - Project 49		5,897.73	(5,960.62)	(62.89)
9732450	WG - C11 - SM - Project 50		5,095.82	(5,158.71)	(62.89)
9732451	WG - C11 - SM - Project 51		4,857.73	(4,920.62)	(62.89)
9732452	WG - C11 - SM - Project 52		6,361.04	(6,423.93)	(62.89)
9732453	WG - C11 - SM - Project 53		5,973.87	(6,398.06)	(424.19)
9732454	WG - C11 - SM - Project 54		6,197.48	(6,260.37)	(62.89)
9732455	WG - C11 - SM - Project 55		3,599.69	(3,662.58)	(62.89)
9732560	WG - C11 - SM - Project 100		1,015.80	(1,058.13)	(42.33)
9732561	WG - C11 - SM - Project 56		5,190.29	(5,208.47)	(18.18)
9732562	WG - C11 - SM - Project 57		3,309.69	(3,372.58)	(62.89)
9732563	WG - C11 - SM - Project 58		6,229.46	(6,292.35)	(62.89)
9732564	WG - C11 - SM - Project 59		5,121.81	(5,184.70)	(62.89)
9732565	WG - C11 - SM - Project 60		10,493.02	(9,595.92)	897.10
9732566	WG - C11 - SM - Project 61		5,515.06	(5,577.94)	(62.88)
9732567	WG - C11 - SM - Project 62		6,324.27	(6,387.16)	(62.89)
9732568	WG - C11 - SM - Project 63		6,106.39	(6,169.28)	(62.89)
9732569	WG - C11 - SM - Project 64		2,000.00		2,000.00
9732570	WG - C11 - SM - Project 65		5,928.55	(5,991.44)	(62.89)
9732571	WG - C11 - SM - Project 66		8,104.68	(8,167.57)	(62.89)
9732572	WG - C11 - SM - Project 67		4,395.40	(4,458.29)	(62.89)
9732573	WG - C11 - SM - Project 68		6,727.56	(6,790.45)	(62.89)
9732574	WG - C11 - SM - Project 69		3,841.73	(3,145.32)	696.41
9732575	WG - C11 - SM - Project 70		5,008.19	(5,071.08)	(62.89)
9732576	WG - C11 - SM - Project 71		8,716.48	(8,779.37)	(62.89)
9732577	WG - C11 - SM - Project 72		5,864.44	(3,927.33)	1,937.11

9732578	WG - C11 - SM - Project 73		4,569.57	(4,632.46)	(62.89)
9732579	WG - C11 - SM - Project 74		7,831.40	(7,894.29)	(62.89)
9732580	WG - C11 - SM - Project 75		7,025.13	(7,088.02)	(62.89)
9732581	WG - C11 - SM - Project 76		143.54		143.54
9732583	WG - C11 - SM - Project 78		1,435.71	(1,478.04)	(42.33)
9732584	WG - C11 - SM - Project 79		4,587.40	(4,650.29)	(62.89)
9732586	WG - C11 - SM - Project 81		4,682.65	(3,916.84)	765.81
9732587	WG - C11 - SM - Project 82		7,937.26	(8,000.15)	(62.89)
9732588	WG - C11 - SM - Project 83		7,876.23	(7,939.12)	(62.89)
9732589	WG - C11 - SM - Project 84		5,615.59	(5,678.48)	(62.89)
9732590	WG - C11 - SM - Project 85		5,002.45	(5,065.34)	(62.89)
9732591	WG - C11 - SM - Project 86		5,277.50	(5,340.39)	(62.89)
9732592	WG - C11 - SM - Project 87		7,023.39	(7,086.28)	(62.89)
9732593	WG - C11 - SM - Project 88		7,572.21	(5,635.10)	1,937.11
9732594	WG - C11 - SM - Project 89		4,075.97	(4,138.86)	(62.89)
9732595	WG - C11 - SM - Project 90		240.00	(282.33)	(42.33)
9732681	WG # Cluster 10 Phase 2		559,394.02		559,394.02
	Total Transmission	**1,657,857.38**	**2,610,739.35**	**(2,353,571.80)**	**1,915,024.93**

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Order	Order Description	Balance 12/31/17	Cost Incurred	Reimbursements received	Balance 12/31/18
9724683	TO-Green Ridge Repowering Facilities Sty	7,404.53		(7,404.53)	-
9725281	Estrella Substation - Facilities Study	(677.55)			(677.55)
9727121	WDT Ripon Independent Study Process	(55,736.76)		55,736.76	-
9727122	WDT Ripon FCDS Full Capac Deliver Status	(13,295.97)		13,295.97	-
9727181	WDT Cabrillo Wind Energy Indep Study	7,348.06		(7,348.06)	-
9727183	R21 Verwey-Hanford Dairy Digestr Det Sty	568.76		(568.76)	-
9727300	WDT-HZI-Waste Conn Fac SLO 4-16 Indep Sy	1,446.94		(1,446.94)	-
9728500	WDT - Apple Hill ES 1 Independent Study	(58,600.74)	79.71	58,521.03	-
9728501	WDT - Apple Hill ES 2 Independent Study	(57,902.83)	79.71	57,823.12	-
9728502	WDT - Apple Hill ES 1 Deliverability Sty	1,686.69	22,311.75	(23,998.44)	-
9728503	WDT - Apple Hill ES 2 Deliverability Sty	(3,138.13)	22,311.75	(19,173.62)	-
9728663	WDT - Poco Power - Fast Track Study	1,978.90		(1,978.90)	-
9728701	WDT - 50001 SCWA North/South Cluster 10	(48,704.94)	2,543.26	46,161.68	-
9728800	R21 David Tevelde Dairy Digester Det Sty	(1,335.62)		1,335.62	-
9728963	R21 Target Corp Shafter Detailed Study	(5,991.83)		5,991.83	-
9729141	WDT - HZIU Kompogas SLO - ISP	(3,429.56)		3,429.56	-
9729180	R21 Charleston East 344360 NEM 2 Det Sty	(1,796.13)		1,796.13	-
9729240	Castroville Energy Stg 5MW Indepent Sty	(3,074.77)		3,074.77	-
9729360	WDT - SEPV Cuyama - Fast Track Study	(16.37)		16.37	-
9729460	WDT - Sirius Ph 3 Fast Track Study	1,139.84		(1,139.84)	-
9729480	R21 Maddox Dairy Ph1 Enos 347251 Det Sty	(4,246.46)		4,246.46	-
9729481	WDT - Madera 2 Fast Tack Study	1,111.41		(1,111.41)	-
9729482	WDT - Kettleman 1 Fast Track Study	(396.71)		396.71	-
9729520	R21 Berrenda Mesa Water 352031 Det Study	(45,502.87)	3,101.62	42,401.25	-
9729522	R21Beldrige Wtr Stor 352165 NEM2 Det Sty	1,110.28	2,128.90		3,239.18
9729523	R21 - SCRWA - ENOS 318636 - Detailed Sty	154.35		(154.35)	-
9729524	WDT - SEPV Cuyama Supplemental Review	(643.56)		643.56	-
9729621	QF 19C010 Humboldt Redwood Facility Sty	(6,278.37)		6,278.37	-
9729681	SPI Quincy - Facilities Study	(5,553.31)		5,553.31	-
9729700	SPI Sonora - Facilities Study	(5,503.40)		5,503.40	-
9729701	WDT - NortBelridge Comm Solar Fast Track	3,152.22		(3,152.22)	-
9729704	WDT - West Paso Community Solar Fast Trk	(396.71)		396.71	-
9729760	WDT - SEPV Cuyama System Impact Study	(4,004.83)		4,004.83	-
9729800	WDT - Cadet Community Solar Fast Track	999.25		(999.25)	-

9729801	WDT - Midway-Sunset Comm Solar Fast Trk	(17.23)		17.23	-
9729804	R21 Premier Int Hold 361723 NEM2 Det Sty	(53,617.87)	168.41	53,449.46	-
9729805	WDT - Nacimiento Interc Study 2017 Indep	2,599.12	7,176.64	(9,775.76)	-
9729806	WDT - Chevron USA Prod Co ISP	(55,768.92)	25,503.83		(30,265.09)
9729807	WDT - Dalena Farms Cluster Study	(41,293.57)		41,293.57	-
9729810	1453-WD BUCCANEER System Impact Study	(6,532.65)		6,532.65	-
9729844	WDT - SEPV Kings - Fast Track	(165.37)		165.37	-
9729861	WDT-1484-WD-North Belridge Com - Sup Rev	324.89		(324.89)	-
9729920	1452-WD Madera 2 - Independent Study	(9,618.87)		9,618.87	-
9729921	Shiloh I Wind Project Facilities Study	(1,813.36)	22,049.91		20,236.55
9729923	Exchequer RAS - CAISO Post COD	(202.13)	4,498.16		4,296.03
9729940	R21 Cache Creek Casino 366552 Det Study	(55,051.42)		55,051.42	-
9729942	R21 Kern Oil Refining (98110) Detail Sty	(5,899.35)		5,899.35	-
9729980	MMA - Q1158 Slate - ISO 51731	1,901.45	3,898.78		5,800.23
9729981	MMA-Q1036 Mustang 2-Gen-Tie-ISO 51601	1,748.70			1,748.70
9730000	MMA - Q1011 GHS Project - ISO 51541	2,861.30	720.00	(3,581.30)	-
9730003	WDT - Midway Sunset Comm Solar Supp Rev	(1,163.82)		1,163.82	-
9730060	MMA - QF Santa Clara Wind - 51155	2,791.43	10,659.21		13,450.64
9730061	MMA - Q1096 & QF Altamont Midway - 51156	2,059.42	10,387.56		12,446.98
9730062	MMA - QF Forebay Wind - 51154	1,599.42	13,303.29		14,902.71
9730065	Q877 California Flats - Roadway PEIE	(572,623.38)	56,043.47		(516,579.91)
9730066	1499-WD - Cadet Community Supp Review	(178.36)		178.36	-
9730068	1419-RD Sandridge Ptnrs NEMA2 Det Study	(3,184.01)		3,184.01	-
9730120	City of Wasco 370604 RESBCT Detailed Sty	(6,663.16)		6,663.16	-
9730121	WDT - Kent Solar Fast Track Study	672.78		(672.78)	-
9730123	R21-Mariposa Biomass Prj-Detailed Study	(6,384.40)	7,411.56	(1,027.16)	-
9730180	MMA - Q1011 GHS Project-Gen-Tie - 51541	85.85		(85.85)	-
9730181	MMA - QF Oroville Cogeneration - 51158	3,721.05	15,343.36	(19,064.41)	-
9730182	WDT - IP Cabernet - Fast Track	879.69		(879.69)	-
9730220	R21 George DeBoer Q-1432-RD Detailed Sty	(6,671.38)		6,671.38	-
9730221	R21 Henry Miller Q-1433-RD Detailed Sty	(6,414.58)		6,414.58	-
9730242	MMA - Q653F SP PVUSA - BESS-ISO 60192-C	1,254.92	2,130.61		3,385.53
9730244	R21 Rijlaarsdam NEMA 2 1483-RD (Det Sty)	(6,280.15)	673.66	5,606.49	-
9730280	MMA-Q1028&29 Ltl Bear Solar1&2-ISO 51587	460.00		(460.00)	-
9730281	WDT - CA-17-0018 SB43 MAHAL (FT)	1,204.71		(1,204.71)	-
9730304	1510-WD Semperviren 2, Shadelands - SR	235.43		(235.43)	-
9730305	WDT IP Malbec - FT	(19.39)		19.39	-
9730320	R21 1458-RD State Center Comm. Detailed	(5,197.90)		5,197.90	-
9730340	WDT - Korbel Power (ISP)	2,848.46	2,486.49	(5,334.95)	-
9730360	Kingsburg Cogen - Facility Study	1,493.72			1,493.72
9730382	WDT-Eurus Energy-Facility Mods Study	(20,499.84)		20,499.84	-
9730420	1469-RD BELRIDGE WATER/Detailed	(8,779.68)	542.86		(8,236.82)
9730421	1513-RD Sandridge Partners/Detailed	(7,015.09)		7,015.09	-
9730441	R21 - Shasta Storage 1/Detailed	(58,612.30)	8,118.89	50,493.41	-
9730481	R21 D ARRIGO BROS CO OF CALIF/Detailed	(7,366.09)	5,091.62	2,274.47	-
9730500	Kent Solar, LLC (1521-WD) - ISP	(797.93)		797.93	-
9730540	WDT Small World Trading - FT	(137.67)	482.96	(345.29)	-
9730580	WDT Semperviren 3 - FT	(261.53)		261.53	-
9730581	R21 Avalon Dairy Digester/Detailed	(8,372.10)	84.18	8,287.92	-
9730600	R21 The Wine Group LLC/Detailed	(10,000.00)		10,000.00	-
9730620	WDT Peterson Road 2/FT	1,996.99		(1,996.99)	-
9730640	WDT - 50003 SCWA R4 - Independent Study	(8,206.35)	2,062.38	6,143.97	-
9730660	WDT - CA-17-0097 SB43 Arco - ISP	1,226.45			1,226.45
9730662	R21 - Bear Creek - EDMUD - Detailed Stdy	(7,313.18)	1,742.15		(5,571.03)
9730664	WDT-CA-17-0101 SB43 Devils Den-Fst Trk	1,870.10	637.37		2,507.47
9730665	WDT-CA-17-0102 SB43 Gates-ISP	(7,157.80)	5,317.41		(1,840.39)
9730666	WDT-CA-17-0106 SB43 Coalinga 1-Fst Trk	(205.19)		205.19	-

9730667	WDT-CA-17-0122 SB43 Coalinga 2-Fst Trk	(349.19)		349.19	-
9730672	WDT - CA-17-0018 SB43 Mahal - Sup Rev	(2,181.98)		2,181.98	-
9730740	CA Department of Corrections #387295/Det	(10,000.00)	4,024.30		(5,975.70)
9730743	WDT CA-17-0100 SB43 Derrick/ISP	(9,261.82)	11,093.91		1,832.09
9730744	WDT - American Canyon Solar A/FT	337.05		(337.05)	-
9730745	WDT - American Canyon Solar B/FT	(714.84)		714.84	-
9730746	WDT - American Canyon Solar C/FT	487.28		(487.28)	-
9730760	R21 EBMUD Enos (387729) RESBCT/Detailed	(54,657.88)	848.29		(53,809.59)
9730784	WDT SEPV American Canyon/FT	206.98			206.98
9730785	WDT Palm Drive Solar A/FT	57.14		(57.14)	-
9730786	WDT Palm Drive Solar B/FT	301.72		(301.72)	-
9730800	R21 - Bangor Solar - 1402-RD - Det Stdy	(10,000.00)	510.50		(9,489.50)
9730820	WDT-CA-17-0090 SB43 Dulgarian/FT	233.16			233.16
9730822	WDT - Merced 2/FT	1,438.38		(1,438.38)	-
9730840	WDT - IP Cabernet_08_2017/FT	(217.78)	84.18	133.60	-
9730861	R21 - City Count of SF (Enos 390303)/Det	(7,995.02)	1,945.79		(6,049.23)
9730862	1529-RD City of Paso Robles/Detailed	(6,924.19)	252.59		(6,671.60)
9730880	WDT - DRES Quarry 2.3/FT	118.85	39.83		158.68
9730881	WDT - IP Merlot 1/FT	146.85		(146.85)	-
9730882	WDT - IP Merlot 2/FT	434.79		(434.79)	-
9730883	WDT - IP Merlot 3/FT	913.24		(913.24)	-
9730920	WDT-SR Sovereign Energy Semperviren 3	(2,066.74)		2,066.74	-
9730940	R21-Calcom Solar-Western Sky Dairy-DS	(849.72)			(849.72)
9730941	R21-OpTerra-S K F Sanitation District-DS	(7,099.86)		7,099.86	-
9730961	WDT - FT - San Rafael Airport Unit No. 2	690.01	425.39	(1,115.40)	-
9730962	WDT - ISP - Intersect Power - IP Porthos	(67,790.89)	240.00	67,550.89	-
9730963	WDT - FT - ZGlobal - Eagle 2 Solar	1,552.47			1,552.47
9730964	WDT - FT - Morris 385 LLC - Morris 385	1,537.23	1,139.98		2,677.21
9730966	WDT - FT - El Pomar Parners - El Pomar	830.99			830.99
9731000	WDT-SR 1561 American Canyon Solar A	(1,344.65)		1,344.65	-
9731002	WDT - SR - 1562 American Canyon Solar B	(1,779.25)		1,779.25	-
9731003	WDT - SR - 1563 American Canyon Solar C	(910.09)		910.09	-
9731020	R21-DS-MaasEn. Lakeside Energy Dairy Dig	(9,545.26)		9,545.26	-
9731040	WDT-SR-Rival Power-Peterson Road 2	532.20	956.05	(1,488.25)	-
9731060	R21 - DS - Chowchilla Dairy Power	(10,000.00)			(10,000.00)
9731061	WDT-FT-ET Solar - Midway Towers Comm Sol	(398.62)	2,104.04		1,705.42
9731062	WDT-FT-ET Solar - East Bay Community Sol	(420.55)	2,679.53		2,258.98
9731063	R21-DS-Sandridge Partners Etal-NEMA	(9,356.43)	3,738.03	5,618.40	-
9731080	MMA - QF Altamont Frick - ISO 51135-QM	562.14		(562.14)	-
9731081	WDT-SR-RenewableProp-Palm Drive Solar A	(1,316.47)		1,316.47	-
9731082	WDT-SR-RenewableProp-Palm Drive Solar B	(1,203.88)		1,203.88	-
9731120	MMA - Q965 Java Solar - ISO 51436	1,279.09	3,616.07	(4,895.16)	-
9731181	WDT-FT-CED White River 2 Battery Storage	292.10		(292.10)	-
9731182	R21 - Musco Olive Biom Gen - Fac Study	(7,870.82)	3,141.90		(4,728.92)
9731183	R21-DS-FoundationWindpower-Mann Packing	(8,222.45)	9,204.27	(981.82)	-
9731187	WDT - FT - ZGlobal - Merced 2	(1,000.00)		1,000.00	-
9731201	WDT - SR - IP Portfolio - IP Cabernet	(1,719.39)	79.71	1,639.68	-
9731202	WDT - SR - IP Portfolio - IP Merlot 1	(1,747.53)	163.91	1,583.62	-
9731203	WDT - SR - IP Portfolio - IP Merlot 2	(1,747.53)	203.76	1,543.77	-
9731204	WDT - SR - IP Portfolio - IP Merlot 3	(1,747.53)	203.76	1,543.77	-
9731205	WDT - SR - El Pomar Partners - El Pomar	(837.91)	626.82		(211.09)
9731206	WDT-SR-ForeFront Power-Ava Elizabeth	(1,360.63)	159.39	1,201.24	-
9731207	WDT-SR-ForeFront Power-Forefront C2	(841.60)	756.40	85.20	-
9731208	WDT-SR-ForeFront Power-Dulgarian	(876.35)	626.08		(250.27)
9731209	WDT - SR - San Rafael Airport Unit #2	(1,454.64)	1,386.22	68.42	-
9731210	WDT - FT - Solar Electric SEPV Cuyama 2	310.23			310.23
9731211	WDT - SR - Green Light - Eagle 2 Solar	(710.62)	956.05		245.43

9731280	R21-DS-BNB Renewable-Campbell Soup Supp	(9,660.92)	14,991.70		5,330.78
9731281	R21-DS-Renewable Solar-Danell Brothers	(8,346.32)	1,663.86		(6,682.46)
9731283	WDT - FT - SFPUC - Burton High School PV	(86.43)	79.70	6.73	-
9731287	R21-DIS-Forefront-CDCR-1569-RD	(10,000.00)	6,824.06		(3,175.94)
9731300	WDT-SR-Forefront Power-Mouren Farming	(974.16)	1,532.37		558.21
9731320	WDT - FT - EPRI - SVUSD Bus Barn Storage	524.47	3,801.86		4,326.33
9731340	R21 - DIS - West Biofuels - SunWest Bio	(9,622.20)	7,703.81		(1,918.39)
9731341	R21 - DIS - Syn Tech - Lisa Boone Harris	(10,000.00)	5,024.36		(4,975.64)
9731360	WDT-SIS-Solar Electric-SEPV Cuyama 2	(9,736.46)	6,182.86		(3,553.60)
9731380	R21-DIS-E&J Gallo Winery-Asti Pond Solar		3,187.55	(10,000.00)	(6,812.45)
9731381	R21-DIS-SunPower-EBMUD RESBCT		13,964.40	(55,000.00)	(41,035.60)
9731382	WDT-Forefront Power-Pistachio Road	(9,491.39)	4,299.55	5,191.84	-
9731383	R21-DIS-Maas Energy-Lakeshore Dairy Dig	(10,000.00)	2,706.73		(7,293.27)
9731480	WDT - FT - REP Energy - VGES 1		1,931.96	(1,931.96)	-
9731481	WDT - FT - REP Energy - VGES 2		1,931.96	(1,931.96)	-
9731482	WDT - SIS - Rival Power Peterson Road 2	(10,000.00)	4,157.48		(5,842.52)
9731484	R21 - DIS - JKB Energy-Trinitas Fund II	(9,491.39)	7,421.36		(2,070.03)
9731502	MMA-Q744 Redwood Solar (Phs4)-ISO 50857	44.05	960.00	(1,004.05)	-
9731503	R21-DIS-Concentric-South County Packing	(10,000.00)	11,099.38		1,099.38
9731504	R21-DIS-ARC Alternatives-City of Lincoln	(10,000.00)	966.79		(9,033.21)
9731507	WDT-FT-REP Energy-DRES Quarry 2.4		931.29	(1,000.00)	(68.71)
9731510	WDT-FT-Renewable Prop-Palm Drive Solar C		2,762.55	(1,000.00)	1,762.55
9731511	WDT-SR-ET Capital-Midway Towers Comm			(2,500.00)	(2,500.00)
9731517	WDT-SR-ET Capital, Inc. East Bay Com Sol			(2,500.00)	(2,500.00)
9731519	WDT-ISP-Calbio Energy-Bar20 Dairy Biogas	(10,000.00)	12,627.57		2,627.57
9731582	R21 - DIS - NRG - Calmat Co. Q#: 1593-RD	(10,000.00)	5,195.50	4,804.50	-
9731620	WDT-ISP-Calbio Energy-MaddoxDairyBiogas		5,702.06	(10,000.00)	(4,297.94)
9731621	WDT-ISP-Calbio Energy-Double Diamond		1,586.22	(10,000.00)	(8,413.78)
9731622	WDT - FT - Forefront Power - Rocha		873.01	(873.01)	-
9731623	MMA - Q1106 Fountain Wind - ISO 51770		637.71	(637.71)	-
9731624	R21-DIS--SunPower-West Valley Mission Co		3,409.23	(10,000.00)	(6,590.77)
9731626	R21-DIS-FirestoneWalker-FirestoneBrewery		4,351.51	(4,351.51)	-
9731640	WDT-SIS-Green Light Energy-Eagle 2 Solar		6,233.09	(10,000.00)	(3,766.91)
9731680	WDT-FT - DG California Solar-Lodi Solar		1,113.51	(1,000.00)	113.51
9731681	WDT-FT-DG California Solar-MendocinoSola		1,866.22	(1,866.22)	-
9731682	R21-DIS-DG Calif Solar, DPIF CA 6 Fresno		5,868.11	(10,000.00)	(4,131.89)
9731700	MMA - Q1141 Alamo Springs - ISO 51745		516.20	(516.20)	-
9731701	MMA - Q1157 Alamo Springs 2 - ISO 51708		200.45	(200.45)	-
9731702	WDT-ISP-Forefront Power-Nachtigall		2,228.73	(10,000.00)	(7,771.27)
9731703	WDT-ISP-Forefront Power-Terry		6,101.64	(6,101.64)	-
9731720	R21-DIS-ARC Alternatives-County of Kern		850.74	(10,000.00)	(9,149.26)
9731722	WDT-SR-Sonoma School-SVUSD Bus Barn Stor		1,449.01	(2,500.00)	(1,050.99)
9731723	WDT-Wireless Sur-Cenergy-NLH1 Solar-0102		1,089.84	(900.00)	189.84
9731724	WDT-ISP-Forefront Power-Broadman		4,047.67	(10,000.00)	(5,952.33)
9731740	R21-DIS-Forefront-CA Dept of Corr 23100		7,993.20	(10,000.00)	(2,006.80)
9731741	R21-DIS-Forefront-CA Dept of Corr 23104		2,815.05	(58,000.00)	(55,184.95)
9731742	R21-DIS-Forefront-CA Dept of Corr 23102		2,334.43	(56,000.00)	(53,665.57)
9731760	WDT-ISP-Forefront-Dulgarian (1589-WD)		5,220.21	(5,220.21)	-
9731761	WDT-ISP-Forefront-Forefront C2 (1587-WD)		4,431.53	(4,431.53)	-
9731762	WDT-ISP-Forefront-Ava Elizabeth 1586-WD		3,502.33	(3,502.33)	-
9731839	WDT - C9P2 - FCDS - Strauss Wind Energy		12,107.74	(12,107.74)	-
9731840	R21-DIS-Newcomb-City of Fresno(App22373)		4,120.71	(72,000.00)	(67,879.29)
9731841	WDT-EIT-Forefront-1584-WD Mouren Farming		4,754.01	(10,000.00)	(5,245.99)
9731842	MMA - Q705 - Frontier Solar - ISO 4411		964.33	(964.33)	-
9731880	MMA - Q877-CA Flats Solar 150-ISO 51211		1,925.53	(1,925.53)	-
9731881	R21-DIS-BloomEnergy-KeysightTechnologies		4,879.90	(10,000.00)	(5,120.10)
9731920	WDT-ISP-CEDWhiteRiverSolar2-WhiteRiver2		4,707.94	(10,000.00)	(5,292.06)

9731921	MMA - Collins Pine Repower - ISO 51161		9,732.02		9,732.02
9731960	WDT-SR-RenewProp-1758WD-PalmDriveSolarC		2,228.46	(2,500.00)	(271.54)
9731980	WDT-FT-OHR Energy-RuAnn Dairy Dig BioMAT		1,123.63	(1,123.63)	-
9731981	WDT-FT-Apex Energy/ZGlobal-Jade Solar		492.17	(1,000.00)	(507.83)
9732000	R21-DIS-SiliconVallCleanWater-12kVSwitch		7,313.96	(10,000.00)	(2,686.04)
9732001	WDT-FT-RenewProp-Silveira Ranch Solar C		1,434.17	(1,000.00)	434.17
9732002	WDT-FT-RenewProp-Silveira Ranch Solar D		1,604.34	(1,000.00)	604.34
9732003	MMA - Thermalito Powerplant - ISO 51162		28,978.38		28,978.38
9732020	WDT-FT-RenewProp-Silveira Ranch Solar A		1,814.76	(1,000.00)	814.76
9732021	WDT-FT-RenewProp-Silveira Ranch Solar B		1,944.67	(1,000.00)	944.67
9732022	WDT-FT - EnSync, Inc - 385 Morris		362.35	(362.35)	-
9732060	WDT-SR: Forefront Power-Rocha-1783-WD		1,768.39	(2,500.00)	(731.61)
9732080	WDT-ISP-YubaCityCogen-WaltonEnergyReliCe		1,714.74	(100,500.00)	(98,785.26)
9732081	WDT-SR: Pathion, Inc. - 1808-WD VGES 1		1,754.77	(1,754.77)	-
9732082	WDT-SR: Pathion, Inc. - 1809-WD VGES 2		2,116.36	(2,116.36)	-
9732100	WDT-ISP: PG&E CoyoteValleyEnergyStorage		14,854.92		14,854.92
9732121	R21-DIS-Forefront- UCSantaCruz App 23113		3,092.36	(10,000.00)	(6,907.64)
9732122	WDT-FT: Forefront Power - Kern Sunset		246.15	(1,000.00)	(753.85)
9732123	WDT-FT: Forefront Power - Highway 43		2,189.96	(1,000.00)	1,189.96
9732124	WDT-FT: Forefront Power - Beard		120.78	(1,000.00)	(879.22)
9732180	WDT-FCDS: Yuba City Cogen-Walton Energy		22,865.28	(50,000.00)	(27,134.72)
9732181	R21-DIS: South Corner Dairy - Q1611-RD		3,303.83	(10,000.00)	(6,696.17)
9732182	WDT-SR: DG Cali Solar - Lodi Solar		1,002.49	(2,500.00)	(1,497.51)
9732260	WDT-ISP: LightsourceRe-Sawmill One Solar		4,284.92	(4,284.92)	-
9732262	WDT-ISP: ETCap-EastBayCommSolar1624-WD		7,951.22	(10,000.00)	(2,048.78)
9732263	R21-DIS:CupertinoElec-WonderfulOrch33018		4,639.53	(10,000.00)	(5,360.47)
9732264	WDT - C9P2 - FCDS - Paso Robles 1311-WD		11,302.71	(11,302.71)	-
9732301	MMA-Q632B-Summer Wheat Solar-ISO 60126C		3,804.54	(3,804.54)	-
9732302	R21-DIS: EnableEnergy-SpecialtyGran34412		1,802.98	(10,000.00)	(8,197.02)
9732303	WDT-FT: Zero Energy - Fallon Two Rock Rd		2,540.90	(1,000.00)	1,540.90
9732304	WDT-ISP: Ormat Nevada-Pease Reliability		964.51	(10,000.00)	(9,035.49)
9732305	WDT-FCDS: Ormat Nevada-Pease Reliability		5,607.16	(50,000.00)	(44,392.84)
9732320	WDT-SR:DGCal-MendocinoSolarHearstWillits		1,830.05	(1,830.05)	-
9732380	R21-DIS: EnableEnergy-SpecialtyGran34465		7,691.45	(10,000.00)	(2,308.55)
9732383	WDT-SR: PatmarLand-RuAnnDairyDig-1864-WD		3,062.83	(3,062.83)	-
9732388	WDT-SR: Silveira Ranch Solar A		2,173.80	(2,500.00)	(326.20)
9732389	WDT-SR: Silveira Ranch Solar B		42.36	(2,500.00)	(2,457.64)
9732390	WDT-SR: Silveira Ranch Solar C		42.36	(2,500.00)	(2,457.64)
9732391	WDT-SR: Silveira Ranch Solar D		42.36	(2,500.00)	(2,457.64)
9732400	WDT-SR: Apex Energy - Jade Solar 1865-WD		3,393.36	(2,500.00)	893.36
9732460	WDT-ISP: Solvida - PutahCreekSolarFarmN			(10,000.00)	(10,000.00)
9732461	WDT-FCDS: Solvida - PutahCreekSolarFarmN		1,466.11		1,466.11
9732462	WDT-FT: BeckwourthGrid-BeckwourthGrid 1		680.67	(1,000.00)	(319.33)
9732464	R21-DS: Daisy Renew - EarlJohn App 37593		10,460.15	(10,000.00)	460.15
9732467	R21-FS: West Biofuels-SunWest Bioenergy		3,995.73	(10,000.00)	(6,004.27)
9732480	WDT-SR: Forefront Power - Kern Sunset		2,181.32	(2,500.00)	(318.68)
9732482	WDT-FT: Kent Solar, LLC - KS Energy		659.11	(1,000.00)	(340.89)
9732483	WDT-SR: Forefront Power - Highway 43		435.15	(2,500.00)	(2,064.85)
9732484	R21-DS: CalCom Solar-Moonlight App 38001		4,448.45	(10,000.00)	(5,551.55)
9732486	R21-EIT: West Coast Waste-1827-RD Gen 1		8,755.92	(10,000.00)	(1,244.08)
9732487	R21-DS: Shasta College - Q#1753-RD			(10,000.00)	(10,000.00)
9732500	WDT-CS: Calpine - Cygnus Power Bank		2,228.95	(100,000.00)	(97,771.05)
9732501	WDT-FCDS: Calpine - Cygnus Power Bank		201.27	(50,000.00)	(49,798.73)
9732503	WDT-FT: CalCom Solar - Toyon		539.89	(1,000.00)	(460.11)
9732520	R21-DS: NextEra-BigDPacBuildSMF3-Q1791RD		1,544.82	(10,000.00)	(8,455.18)
9732523	WDT-SR: Forefront Power -Beard Q1888-WD		3,167.41	(2,500.00)	667.41
9732620	WDT-CS: ScoutClean-Gonzaga Ridge Wind 3		1,881.26	(1,881.26)	-

9732621	WDT-FCDS: ScoutClean-GonzagaRidgeWind3		40.07	(40.07)	-
9732622	WDT-EIT: FFPCACommSolar Rocha - 1783WD		5,687.45	(10,000.00)	(4,312.55)
9732660	R21-DS: Ecoplexus-CANatGuard-Q1786-RD		2,458.77	(10,000.00)	(7,541.23)
9732680	R21-DS: Cupertino E-Wonderful Orch 41293		5,812.68	(10,000.00)	(4,187.32)
9732720	R21-DS: SyntechBioenergy-RiverOakOrchard		8,786.28	(10,000.00)	(1,213.72)
9732721	R21-SR: Charlies Enterprises 1909-RD			(2,500.00)	(2,500.00)
9732780	MMA-Q954-Fifth Standard Solar-ISO 51419		315.71	(315.71)	-
9732781	Repower - Kelly Ridge Powerhouse - SFWPA		11,235.19		11,235.19
9732820	WDT-CS: Origis Operating-Vaquero Storage		2,304.43	(111,000.00)	(108,695.57)
9732821	WDT-FCDS: OrigisOperating-VaqueroStorage		80.15	(50,000.00)	(49,919.85)
9732840	WDT-SIS: Forefront Power - Kern Sunset		5,922.12	(10,000.00)	(4,077.88)
9732841	WDT-SIS: Forefront Power,LLC-Highway 43		3,324.35	(10,000.00)	(6,675.65)
9732842	R21-DS: COofCali DArrigo Bros 114202422		6,204.45	(10,000.00)	(3,795.55)
9732843	WDT-FT: SFPUC-Starr King PV Installation		1,399.71	(1,000.00)	399.71
9732844	R21-DS: BessieDig-HilltopHolsteins 38098		10,440.76	(10,000.00)	440.76
9732845	WDT-SR: Zero Energy Construct-Highway 43		164.29	(2,500.00)	(2,335.71)
9732846	WDT-CS: Calpine Corp-Panthera Power Bank		2,157.94	(79,000.00)	(76,842.06)
9732847	WDT-FCDS: CalpineCorp-PantheraPowerBank		40.07	(50,000.00)	(49,959.93)
9732848	WDT-CS: Capine Corp-Riverrun Power Bank		2,149.63	(99,000.00)	(96,850.37)
9732849	WDT-FCDS: CapineCorp-Riverrun Power Bank		40.07	(50,000.00)	(49,959.93)
9732880	R21-DS: ACElectric-RogerVGroningen 45330		4,316.39	(10,000.00)	(5,683.61)
9732881	MMA-Q946-Northern Orchard Solar-ISO51400		340.67	(340.67)	-
9732882	WDT-FT: Soltage-Bradley Gillett Solar 1		1,336.47	(1,000.00)	336.47
9732883	WDT-FT:Soltage-San Ardo Pine Vly Solar 1		681.80	(1,000.00)	(318.20)
9732900	WDT-SIS: RenewableProp-SilveiraRanchSolA		9,726.88	(10,000.00)	(273.12)
9732901	WDT-SIS: RenewableProp-SilveiraRanchSolB		5,924.65	(10,000.00)	(4,075.35)
9732902	WDT-SIS: RenewableProp-SilveiraRanchSolC		5,344.25	(10,000.00)	(4,655.75)
9732904	R21-DS: PhoenixEner-NapaRecBiomass2MW		4,057.37	(10,000.00)	(5,942.63)
9732905	R21-DS: AmericanCommod-AbelRoadBioenergy		8,270.62	(10,000.00)	(1,729.38)
9732906	MMA - Q1032 Tranquility 8 - ISO 51600		1,289.99	(1,289.99)	-
9732907	WDT-FT: Engie-Hayward EBCE Array		6,423.55	(1,000.00)	5,423.55
9732908	WDT-ISP:Berry Petroleum-Berry NMW Cogens		6,517.96	(60,000.00)	(53,482.04)
9732909	R21-DS: AmericanCommod-Willows Bioenergy		5,164.10	(10,000.00)	(4,835.90)
9732940	WDT-FAS: Bar20Dairy - Bar20Dairy1754-WD			(15,000.00)	(15,000.00)
9732941	MMA - Q1011 Colinas de Oro - ISO 51541		989.45		989.45
9732960	WDT-SR: PristineSunFund6-RGA2/SH1 Solar		1,585.32	(2,500.00)	(914.68)
9732961	R21-DS: Sunpower-TheGapInc-App46139NEMMT		4,781.63	(10,000.00)	(5,218.37)
9732962	R21-DS: City of Lincoln (Airport)		7,837.43	(10,000.00)	(2,162.57)
9733020	MMA - Q1129 Luna Valley - ISO 51746		648.01	(648.01)	-
9733060	WDT-EIT/SIS: ForefrontPower-Beard1888-WD		3,504.25	(10,000.00)	(6,495.75)
9733061	WDT-SR: Kent Solar, LLC - KS Energy		1,074.41	(2,500.00)	(1,425.59)
9733080	MMA1-Q1030 South Lake Solar-ISO 51604		767.96	(767.96)	-
9733081	WDT-SR: SoltageCaDevCo-SanArdoValleySol1		2,414.51	(2,500.00)	(85.49)
9733082	WDT-SR: Soltage,LLC-BradleyGillettSolar1		2,948.40	(2,500.00)	448.40
9733083	MMA1-NoQ Moss Landing Unit 6-ISO 51164		7,571.01		7,571.01
9733160	WDT-ISP: CalpineCorporation-CalSunSolar		3,936.36	(70,000.00)	(66,063.64)
9733161	WDT-ISP: REP Energy-V7 Solar Ranch		810.11	(810.11)	-
9733164	WDT-FT: GoldenStateRenew-GSRETurkIsland		1,614.22	(1,000.00)	614.22
9733165	WDT-FT: GoldenStateRenew - GSRE-OSP		452.64	(1,000.00)	(547.36)
9733166	R21-DS:ArcAlternativesElDoradoUHSD1782RD		180.63	(10,000.00)	(9,819.37)
9733167	MMA - Q1260 NoOrchard3Solar - ISO 51919		380.06	(380.06)	-
9733168	MMA - Q1259 NoOrchard2Solar - ISO 51918		702.27	(702.27)	-
9733169	WDT-FAS: GreenLightEnergy-Eagle 2 1620WD		246.90	(15,000.00)	(14,753.10)
9733180	MMA - QF FrickSummitRepower - ISO 51135		3,308.79		3,308.79
9733181	R21-DS: Google-MFABayviewFacSolar50088		1,236.29	(10,000.00)	(8,763.71)
9733182	WDT-FT: SoltageCA-AlamedaGrantLineSolar1		520.72	(520.72)	-
9733183	WDT-ISP: ZGlobal - Jade Solar_July 2018		12,927.54	(10,000.00)	2,927.54

9733200	R21-DS: PhoenixEnergy-NorthForkComPower		21,341.75	(10,000.00)	11,341.75
9733201	R21-DS: PhoenixEnergy-BlueMountainElectr		15,279.91	(10,000.00)	5,279.91
9733240	R21-DS: West Biofuels - Hat Creek Bioene			(10,000.00)	(10,000.00)
9733300	MMA-Q1120 Chestnut Westside-ISO 51818		243.72	(243.72)	-
9733301	MMA-Q1139 Westlands Solar Blue-ISO 51815		325.86	(325.86)	-
9733302	WDT-ISPReStudy: Strauss Wind Energy, LLC		7,903.67	(30,000.00)	(22,096.33)
9733303	EGI: Forbestown PH - SFWPA - Testing		342.45		342.45
9733304	WDT-SIS:Soltage,LLC-BradleyGillettSolar1		7,766.10	(10,000.00)	(2,233.90)
9733306	R21-DS-BASSLAKEJOINTELESchApp55332RESBCT		4,661.61	(10,000.00)	(5,338.39)
9733320	R21DIS:CityofMaderaRES-BCT (App 54517)		968.23	(10,000.00)	(9,031.77)
9733321	WDT-SIS:Soltage,SanArdoPineValleySolar1		5,536.12	(10,000.00)	(4,463.88)
9733322	Rule21:DS-MMRConsWAWONAFROZENFOODS-50318		360.26	(58,000.00)	(57,639.74)
9733323	WDT-FT-SolarElectricSolution-SEPVBarbar3		1,047.59	(1,000.00)	47.59
9733340	R21:DS-EL DORADO IRRIGATION DISTRICT		2,553.19	(10,000.00)	(7,446.81)
9733341	R21DIS:CA DEPT of CORRECTIONS(App55059)		514.77	(57,000.00)	(56,485.23)
9733360	MMA - Q1027 Blackbriar - ISO 51565 - COD		322.79	(322.79)	-
9733361	MMA - NoQ# - Patterson Pass - ISO 51137		1,701.30	(981.30)	720.00
9733380	WDT-FT-WildcatRenewableRPSantaCruzSolar1		2,376.99	(1,800.00)	576.99
9733381	WDT-FT-WildcatRenewableRPSantaCruzSolar2		2,448.89	(1,800.00)	648.89
9733382	Rule21:DS-JKB EnergySierraPacificAP55806		1,854.24	(59,000.00)	(57,145.76)
9733385	WDT-FT-ApexEnergySolutionsGasCoRdSolar1		345.48	(1,000.00)	(654.52)
9733427	MMA #5 - Q1036 Mustang 2 - ISO 51601		3,256.16		3,256.16
9733428	MMA-Q1116-Ultrapower Chinese-ISO 51707		1,241.16	(1,241.16)	-
9733440	WDT-SR-GoldenStateReneEng-GSRETurkIsland			(2,500.00)	(2,500.00)
9733480	Rule21:DS-DeltaDiabloCo-Digestion1968-RD		2,901.94	(10,000.00)	(7,098.06)
9733500	MMA-Q720&1002-LassenLodgeHydro-ISO 50773		730.85	(730.85)	-
9733540	WDT-FastTrack-Universal Solar-USPPGE9918		336.42	(1,000.00)	(663.58)
9733541	WDT-FastTrack-Universal Solar-USPPGE8918		336.42	(1,000.00)	(663.58)
9733542	WDT-FastTrack-Universal SolarUSPPGE-7918		199.30	(1,000.00)	(800.70)
9733543	WDT-FastTrack-Universal Solar-USPPGE6918		120.91	(1,000.00)	(879.09)
9733545	WDT-FastTrack-Universal Solar-USPPGE4918		120.91	(1,000.00)	(879.09)
9733546	WDT-FastTrack-Universal Solar-USPPGE3918		484.90	(1,000.00)	(515.10)
9733547	WDT-Fas Track-Universal Solar-USPPGE2918		199.30	(1,000.00)	(800.70)
9733548	WDT-Fast Track-UniversalSolar-USPPGE1918		738.22	(1,000.00)	(261.78)
9733549	WDT-FT-NatelEnergyc/oKinetMurphyHydro		683.50	(1,000.00)	(316.50)
9733550	WDT-FT-RENESOLAPOWERHOL-OspreySolar		1,281.94	(1,000.00)	281.94
9733552	WDT-PS-UticaWater&Power(UWPA)-AngelPower		3,360.47	(5,000.00)	(1,639.53)
9733553	WDT-FT-ReneSolaPowerHoldingsTaylorSolar		1,332.74	(1,000.00)	332.74
9733561	R21-Detailed Study-STAMOULES PRODUCE		2,397.22	(10,000.00)	(7,602.78)
9733562	Rule21DSBerryPetroleumCompy-BerryCogen18		538.41		538.41
9733581	WDT#SR-CITYOFHAYWARDHaywardEBCEArray			(2,500.00)	(2,500.00)
9733600	MMA-Q1278-Westwood Energy Ctr-ISO 52013		1,785.60		1,785.60
9733602	WDT:FT - Pine Flat Solar 1 - Apex Energy		525.33	(1,000.00)	(474.67)
9733603	WDT:FT - Merced 3 - Apex Energy		718.49	(1,000.00)	(281.51)
9733620	WDT-FastTrack-Calcom Solar-Sycamore-Napa		4,852.66	(1,000.00)	3,852.66
9733621	WDT-SIS- Kent Solar-LLC-KS Energy		606.93		606.93
9733640	WDT-SR-RenewableRPSantaCruzSolarQ2031WDT		1,852.11	(2,500.00)	(647.89)
9733641	WDT-SR-RenewableRPSantaCruzSolar1Q2030WD		1,852.11	(2,500.00)	(647.89)
9733642	R21#Detailed Study-Superior Packing Co.		694.40	(10,000.00)	(9,305.60)
9733643	R21:DS:NextEraEnerg114971313DGCAWestside			(58,000.00)	(58,000.00)
9733660	WDT-ISP/FCDS-DGCali-YubaCityEnergyStorag		323.95	(10,000.00)	(9,676.05)
9733681	WDT:FT - Corda I - Cratus Energy Mgmt		2,076.11	(1,000.00)	1,076.11
9733682	WDT:FT - Corda II - Cratus Energy Mgmt		2,076.11	(1,000.00)	1,076.11
9733700	MMA2 - Q1141 Alamo Springs - ISO 51745		530.79		530.79
9733701	MMA2 - Q1157 Alamo Springs 2 - ISO 51708		215.98		215.98
9733702	WDT:FT - Gonzales - FFP CA Com Solar		545.12	(1,000.00)	(454.88)
9733703	WDT:FT - Washoe Ave - FFP CA Com Solar		1,640.21	(1,000.00)	640.21

9733704	WDT:SR - Osprey Solar - Renesola Power		107.69	(2,500.00)	(2,392.31)
9733705	R21-DS: WonderfulPistachios&Almonds66478			(69,000.00)	(69,000.00)
9733720	R21-DS: Wonderful Pistachios & Almonds			(10,000.00)	(10,000.00)
9733761	MMA2 - Q1106 Fountain Wind - ISO 51770		803.51		803.51
9733762	WDT:ISP - Tranquility - FFP CA Com Solar		3,029.44	(10,000.00)	(6,970.56)
9733763	WDT:ISP - Munoz - FFP CA Com Solar		1,972.59	(10,000.00)	(8,027.41)
9733764	R21-DS: WonderfulPistachios&Almonds67792		1,215.61	(10,000.00)	(8,784.39)
9733765	WDT:SR - 2040-WD - Gas Co Road Solar 1		2,660.75	(2,500.00)	160.75
9733767	R21:DS - City of San Jose (App 68019)			(78,000.00)	(78,000.00)
9733780	WDT:ISP - Leo Solar - Apex Energy		212.76	(10,000.00)	(9,787.24)
9733840	R21:DS - RWA/UCM Cogen-Merced Co RWM			(10,000.00)	(10,000.00)
9733842	R21-DS: MacphersonOil-RoundMountainSolar			(10,000.00)	(10,000.00)
9733843	WDT-SR: SycamoreGroup-SycamoreNapa2066WD			(2,500.00)	(2,500.00)
9733862	WDT–FillInStudyReneSolaPowerTaylorSolar		71.77	(2,500.00)	(2,428.23)
9733881	MMA1 - Q1239 Medeiros Solar - ISO 40030		997.51		997.51
9733900	WDT-FT-ApexEnergySolutionsPineFlatSolar2			(1,000.00)	(1,000.00)
9733901	WDT-FT-ApexEnergSolutionGasCoRoadSolar2			(1,000.00)	(1,000.00)
9733920	WDT-SR-SolarElectricSolutionSEPVBarbara3			(2,500.00)	(2,500.00)
9733921	WDT–SR-Kinet Inc-Murphys Afterbay Hydro		1,102.67	(2,500.00)	(1,397.33)
9733922	Rule21:DS-GRANITEROCKCOMPANY(App69212)			(10,000.00)	(10,000.00)
9733923	WDT:SR-Manning Avenue-FFP CA Com Solar		794.60	(2,500.00)	(1,705.40)
9733924	Rule21-DS-ChicoElectricRoplastApp#4959		75.88	(10,000.00)	(9,924.12)
9733925	WDT-FT-Apex Energy Solutions-Lara Solar		642.84	(1,000.00)	(357.16)
9733926	WDT-FT-Apex Energy Solutions-Leo Solar2		251.25	(1,000.00)	(748.75)
9733929	WDT-FT-FFPCACommunitySolarBroadman2			(1,000.00)	(1,000.00)
9733930	WDT-SR-ApexEnergySolutionsPineFlatSolar1		830.47	(2,500.00)	(1,669.53)
9733931	Rule21DS-GOLDENSTATEFC-App71807			(10,000.00)	(10,000.00)
9733941	WDT-FT-ApexEnergySolutionsPineFlatSolar3		303.48	(1,000.00)	(696.52)
9734001	WDT:SR - 2083-WD-Corda 1 - Cratus Energy			(2,500.00)	(2,500.00)
9734002	WDT:SR - 2084-WD-Corda II-Cratus Energy			(2,500.00)	(2,500.00)
9734003	WDT-FT-ApexEnergySolutionsLLCLeoSolar3			(1,000.00)	(1,000.00)
9734045	WDT:FT - WHI Solano R&D - Wind Harvest			(1,000.00)	(1,000.00)
9734101	R21:DS - Fowler Packing Co - App 76191			(10,000.00)	(10,000.00)
9734102	R21:DS - Fowler Packing Co - App 76185			(10,000.00)	(10,000.00)
9734142	MMA1 - Q1010-Dyer - ISO 51539		152.83		152.83
9731721	R21-DIS-Syntech Bioenergy-Carriere Fam F		5,908.91	(10,000.00)	(4,091.09)
9732481	R21-DS: TONY MEIRINHO DAIRY AND SONS		3,623.13		3,623.13
9732760	R21-DS: Marysville Joint Unified School		1,924.68	(10,000.00)	(8,075.32)
9733120	R21-DS: County of Kern - Industrial		695.40	(10,000.00)	(9,304.60)
9733121	R21-DS: County of Kern - Mt. Vernon		869.41	(10,000.00)	(9,130.59)
9733560	Rule21:DSFresnoUnifiedSchoolSunnysideH.S		971.61	(10,000.00)	(9,028.39)
9733580	Rule21DS-Re-evaluation-SanJoaquinCounty		1,550.07	(10,000.00)	(8,449.93)
9726820	R21-Livermore Community Solar Frm-Det St	11,106.72		(11,106.72)	-
9729922	R21 Merced County RES-BCT Detailed Study	(7,575.61)		7,575.61	-
9731460	R21-DIS-Golden State FC-Golden State		8,899.68	(10,000.00)	(1,100.32)
9731625	R21-DIS-Crimson Resources-Crimson Resour		7,064.01	(10,000.00)	(2,935.99)
9732300	R21-EIT: SynTech-1627-RD Colusa Ind Park		7,862.46	(10,000.00)	(2,137.54)
9732850	R21-DS: ACElectric-SangerColdStor1844RD		2,583.93	(2,583.93)	-
	Total Generation	**(1,621,346.18)**	**1,120,039.17**	**(2,034,585.27)**	**(2,535,892.28)**

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	AB802 Memo Account - Electric	325,759	593,605	400		919,364
2	(amortization: < 12 months)					
3	AB802 Memo Account - Gas	266,531	485,676	400		752,207
4	(amortization: < 12 months)					
5	Acc Amt - Plant RA Tax	(161,887,481)		405	3,520,572	-165,408,053
6	(amortization: 11 years)					
7	Accum Amort - URG Plant Reg Asset	3,520,575		405		3,520,575
8	(amortization: < 12 months)					
9	Accum Amort - URG Plant Reg Asset Non Current	(646,489,723)		405	42,243,000	-688,732,723
10	(amortization: 12 years)					
11	AMCDOP- Cost Adjust Mechanism	49,846,489	54,347,071	400	66,232,297	37,961,263
12	(amortization: < 12 months)					
13	Balancing Account - Utility Generation	(13,857,924)	2,346,308,203	400	2,253,502,275	78,948,004
14	(amortization: < 12 months)					
15	BCA Charge Account	440,258	3,228,320	400	2,721,930	946,648
16	(amortization: <12 months)					
17	Biomass Memo Account	357,908	51,287,488	555	22,554,764	29,090,632
18	(amortization: < 12 months)					
19	Bioram Memo Account	5,775,726	16,787,864	555	13,111,548	9,452,042
20	(amortization: < 12 months)					
21	CA Alternate Rates for Energy Program-Electric	23,438,916	516,932,147	400	497,729,243	42,641,820
22	(amortization: < 12 months)					
23	CA Alternate Rates for Energy Program-Gas	(21,906,240)	124,145,197	400	126,548,962	-24,310,005
24	(amortization: < 12 months)					
25	CA Solar Initiative Thermal Program Memo Account	6,742,115	7,446,999	400	6,190,940	7,998,174
26	(amortization: < 12 months)					
27	Catastrophic Event Memorandum Account	527,923,691	821,286,585	182.3	681,331,001	667,879,275
28	(amortization: <12 months)					
29	CEE Incentive Electric Balancing Account	2,471,330	21,457	400	3,750,049	-1,257,262
30	(amortization: < 12 months)					
31	CEE Incentive Gas Balancing Account	212,379	550,223	400	146,331	616,271
32	(amortization: < 12 months)					
33	Core Brokerage Fee	1,183,803	6,507,572	400	6,539,622	1,151,753
34	Amortization : < 12 MONTHS					
35	Core Fixed Cost Gas Balancing Account	288,383,643	2,583,642,839	400	2,538,624,137	333,402,345
36	(amortization: < 12 months)					
37	Core Pipeline Demand Charge Account	12,944,626	507,268,450	400	506,722,166	13,490,910
38	(amortization: < 12 months)					
39	Critical Docs Program memo Acct NC	6,260,968	5,760,560	182.3	3,577,132	8,444,396
40	(amortization: > 12 months)					
41	DCRBA - DCPP Employee Retention Program		66,678,204	400	33,891,874	32,786,330
42	(amortization : > 12 months)					
43	Deferred Debit - Gas Reserves (Contra Balancing Ac	(206,150,601)	338,716,664	400	466,934,661	-334,368,598
44	TOTAL	5,018,800,793	26,561,571,526		25,734,889,740	5,845,482,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	(amortization: < 12 months)					
2	Demand Response Expenditures BA - DRAM		4,773,654	182.3	18,298,415	-13,524,761
3	(amortization: > 12 months)					
4	Demand Response Expenditures B/A (DREBA)	(7,884,859)	36,450,378	400	36,287,129	-7,721,610
5	amortization: < 12 months					
6	Department of Energy Litigation Balancing Account	(15,017,083)	15,230,427	182.3	29,270,198	-29,056,854
7	(amortization: > 12 months)					
8	Diablo Canyon Seismic Studies Balancing Acct	17,360,285	4,636,128	182.3	12,723,018	9,273,395
9	(amortization: < 12 months)					
10	Diablo Canyon Retirement Bal Acct (DEPR) - NC		24,083,136	400	2,090,749	21,992,387
11	(amortization: > 12 months)					
12	Distribution Revenue Adjustment Mechanism	(71,915,222)	4,908,351,283	400	4,676,758,177	159,677,884
13	(amortization: < 12 months)					
14	Distributed Resources Plan Memorandum Acct		1,211,975	400	716,598	495,377
15	(amortization: > 12 months)					
16	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
17	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
18	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
19	Electric Balancing Account Reserve Account	(707,101,109)		400	292,898,890	-999,999,999
20	Electric Balancing Account Reserve Account		748,968,524	400	999,999,999	-251,031,475
21	Electric Balancing Account Reserve Account			400	133,840,006	-133,840,006
22	(amortization: < 12 months)					
23	Electric Hazardous Substance Balancing Account	35,775,193	75,060,107	182.3	71,623,102	39,212,198
24	(amortization: < 12 months)					
25	Electric Price Risk Management - Current	43,680,363	149,761,224	555	166,073,774	27,367,813
26	Electric Price Risk Management - NonCurrent	64,887,869	286,879,321	555	262,053,131	89,714,059
27	Electric Program Investment Charge	4,303,871	93,744,038	400	100,847,846	-2,799,937
28	(amortization: < 12 months)					
29	End-Use Customer Refund Adjustment	(18,724,310)	13,531,597	400	2,572,825	-7,765,538
30	(amortization: < 12 months)					
31	Energy Recovery Bonds Balancing Account	(3,772,785)	47,868,046	400	90,491,604	-46,396,343
32	(amortization: < 12 months)					
33	Energy Resource Recovery Account	70,591,762	3,731,544,376	400	3,855,245,475	-53,109,337
34	(amortization: < 12 months)					
35	Environmental Compliance	159,159,599	92,687,558	182.3	28,568,149	223,279,008
36	(amortization: 32 years)					
37	Environmental Compliance Non-HSM	40,989,049	4,164,084	228.4	5,883,630	39,269,503
38	(amortization: 32 years)					
39	Family Electric Rate Assistance Balancing Acct	6,396,125	5,340,841	400	6,396,125	5,340,841
40	(amortization: < 12 months)					
41	FIN 47 - Regulatory Asset	17,558,036	3,921,979	101	2,325,533	19,154,482
42	Financing Costs - Current	1,507,230		428	126,659	1,380,571
43	(amortization: < 12 months)					
44	TOTAL	5,018,800,793	26,561,571,526		25,734,889,740	5,845,482,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Financing Costs Regulatory Asset	17,025,505	126,659	428	1,495,281	15,656,883
2	(amortization: 20 years)					
3	Fire Hazard Prevention Memo Acct	1,078,845	384,213,494	182.3	76,516,282	308,776,057
4	(amortization: < 12 Months)					
5	Gas Core Firm Storage Account	2,836,042	73,689,333	400	72,263,354	4,262,021
6	(amortization: < 12 months)					
7	Gas Hazardous Substance Balancing Account	83,475,448	174,970,574	182.3	166,950,894	91,495,128
8	(amortization: < 12 months)					
9	Gas Hazardous Substance Regulatory Asset	375,144,418	213,630,555	182.3	67,790,619	520,984,354
10	(amortization: 32 years)					
11	Gas Non-Hazardous Substance Regulatory Asset	133,533,910	1,098,204	228.4	1,559,252	133,072,862
12	(amortization: 32 years)					
13	Gas Pipeline Expense and Capital Balancing Account	3,436,048	404,792	400	3,538,382	302,458
14	(amortization: <12 months)					
15	Gas Price Risk Management - Current	1,084,177	5,561,104	807	4,984,714	1,660,567
16	GPBA-Greenhouse Gas Compliance Subaccount	157,201,621	97,708,033	400	203,017,081	51,892,573
17	(amortization: < 12 months)					
18	Gas Public Purpose Program Surcharge Memo Acct	45,383,994	262,600,117	186	263,513,722	44,470,389
19	(amortization: < 12 months)					
20	Gas Transmission and Storage Memo Account (GTSMA)	180,904,540	120,214,886	400	188,206,878	112,912,548
21	(amortization: < 12 months)					
22	Gas Transmission and Storage Revenue Sharing Mech.	18,143,605	409,981,159	400	435,704,157	-7,579,393
23	(amortization: < 12 months)					
24	GPBA - GHG Operational Cost Subaccount	27,406,445	20,648,625	400	42,120,504	5,934,566
25	(amortization: < 12 months)					
26	Green Tariff Shared Renewables Bal Acct	106,047	10,165,144	400	5,772,392	4,498,799
27	(amortization: < 12 months)					
28	Greem Tariff Shared Renewables Memo Acct	4,996,470	1,545,419	400	883,302	5,658,587
29	(amortization: < 12 months)					
30	Greenhouse Gas Expense Memo Account - E	(1,892,397)	901,485	400	28,770	-1,019,682
31	Greenhouse Gas Expense Memo Account - G	334,859	889,891	400	374,120	850,630
32	(amortization: < 12 months)					
33	Hydro Licensing Balancing Account	(20,372,843)	1,304,870	182.3	28,015,544	-47,083,517
34	Hydro Pipeline Testing Memo Acct		90,115,840	182.3		90,115,840
35	(amortization: > 12 months)					
36	Integrated Distribution Energy Resources Account	71,232	151,908	400		223,140
37	(amortization: > 12 months)					
38	Land Conserv. Plan Env. Remediation Memo Acct.	746,381	1,400,211	182.3	746,382	1,400,210
39	(amortization: < 12 months)					
40	Line 407 Memo Acct NC	301,110	3,468,913	182.3	295,206	3,474,817
41	(amortization: > 12 months)					
42	Major Emergency Balancing Account	288,710	103,517,472	182.3	125,770,895	-21,964,713
43	(amortization: < 12 Months)					
44	TOTAL	5,018,800,793	26,561,571,526		25,734,889,740	5,845,482,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Miscellaneous Elec-Current-FERC Interest Bearing		57,292,448	400	1,291	57,291,157
2	(amortization: < 12 months)					
3	Miscellaneous Electric Reg Asset - Current	481,041,835	171,448,117	Various	623,567,816	28,922,136
4	(amortization: < 12 months)					
5	Miscellaneous Electric Reg Asset - NonCurrent	9,638,677	413,600,941	549	259,694,970	163,544,648
6	(amortization: 25 years)					
7	Miscellaneous Gas Reg Asset - Current	3,865,759	20,518,440	Various	443,763	23,940,436
8	(amortization: < 12 months)					
9	Mobile Home Park Balancing Account - Electric	7,093,489	37,835,958	182.3	26,368,081	18,561,366
10	(amortization: < 12 months)					
11	Mobile Home Park Balancing Account - Gas	7,269,902	37,119,683	182.3	26,764,471	17,625,114
12	(amortization: < 12 months)					
13	Modified transition cost balancing account	(10,808,975)	110,636,874	400	81,724,460	18,103,439
14	(amortization: < 12 months)					
15	Negative Ongoing Competition Transition Chrg BA	3,089,668,292	109,931,615	182.3	179,905	3,199,420,002
16	(amortization: < 12 months)					
17	New System Generation BA	(46,650,016)	321,811,469	400	156,216,930	118,944,523
18	(amortization: < 12 months)					
19	New Environmental Regulations Balancing Acct		34,249,572	182.3	23,699,624	10,549,948
20	(amortization: < 12 months)					
21	Non Current HSM BA Elec	38,439,275	57,450,004	182.3	67,007,423	28,881,856
22	(amortization: > 12 months)					
23	Non Current HSM BA Gas	89,691,641	134,050,008	182.3	156,350,654	67,390,995
24	(amortization: > 12 months)					
25	Noncurr Wildfire Exp Memo Acct - Elec		213,354,963	182.3		213,354,963
26	(amortization: > 12 months)					
27	Noncurr Wildfire Exp Memo Acct - Gas		103,948,670	182.3		103,948,670
28	(amortization: > 12 months)					
29	Nuclear Decommissioning Adjustment Mechanism	(45,752,788)	69,235,497	400	40,935,684	-17,452,975
30	(amortization: 2 years)					
31	Nuclear Regulatory Commission Rulemaking Costs BA	8,001,467	42,424,044	182.3	36,255,129	14,170,382
32	(amortization: > 12 Months)					
33	Pension Regulatory Asset	1,953,963,992	151,311,609	926	158,171,730	1,947,103,871
34	(amortization: indefinite)					
35	Procurement Energy Efficiency Rev. Adj. Mechanism	11,603,488	334,265,163	400	337,429,250	8,439,401
36	(amortization: < 12 months)					
37	Public Purpose Programs Revenue Adjustment Mech.	(26,720,208)	203,534,997	400	205,662,867	-28,848,078
38	(amortization: < 12 months)					
39	Purchased Gas Balancing Account	2,119,259	1,629,992,206	400	1,621,443,629	10,667,836
40	(amortization: < 12 months)					
41	Reg Asset - Abandoned Capital Projects	18,324,235	20,622,784	400	13,928,167	25,018,852
42	(amortization: < 12 months)					
43	Reg Asset - Mobilehome park BA - E Noncurrent	15,117,286	18,860,040	597	9,244,074	24,733,252
44	TOTAL	5,018,800,793	26,561,571,526		25,734,889,740	5,845,482,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	(amortization: < 12 months)					
2	Reg Asset - Mobilehome park BA - G Noncurrent	17,475,604	16,982,398	893	6,741,494	27,716,508
3	(amortization: < 12 months)					
4	Reg Asset - Mobilehome park BA - E Current	1,622,479	3,546,678	597	2,737,651	2,431,506
5	(amortization: < 12 months)					
6	Reg Asset - Mobilehome park BA - G Current	1,806,908	3,990,547	893	3,066,169	2,731,286
7	(amortization: < 12 months)					
8	Reg Asset - Hydro Non Current	10,758,023	107,529	400	9,107	10,856,445
9	(amortization: > 12 months)					
10	Reg Asset - Cema Elec Non Current	322,049,440	910,598,355	588	239,781,569	992,866,226
11	(amortization: > 12 months)					
12	Reg Asset - Cema Gas Non Current	26,429,472	24,417,732	388	2,128,697	48,718,507
13	(amortization: > 12 months)					
14	Reg Asset - Miscellaneous Gas - Non-Current		101,035,834	925, 408.1	70,274,180	30,761,654
15	(amortization: > 12 months)					
16	Reliability Services Balancing Account	(410,816)	69,850,963	400	125,330,531	-55,890,384
17	(amortization: < 12 months)					
18	Residential Rate Reform Memorandum Account (RRRMA)	19,253,940	18,292,957	182.3	20,910,559	16,636,338
19	(amortization: < 12 months)					
20	Tax Normalization Memo Account (TNMA)	9,965,012	9,464,934	400	4,165,656	15,264,290
21	(amortization: > 12 months)					
22	Transition Cost - Noncore Balancing Account	(2,314,575)	180,038,106	400	211,168,204	-33,444,673
23	(amortization: < 12 months)					
24	Transmission Access Charge Balancing Account	139,010,141	455,486,736	400	466,887,276	127,609,601
25	(amortization: < 12 months)					
26	Transmission Revenue Balancing Account	(101,030,150)	269,566,411	400	239,282,193	-70,745,932
27	(amortization: < 12 months)					
28	Unamortized Financial Hedging Cost	12,779,845		428	836,195	11,943,650
29	(amortization: 20 years)					
30	Unamortized Financial Hedging Cost Current	836,195		428		836,195
31	(amortization: < 12 months)					
32	URG Plant Regulatory Asset - current	42,239,000		407.4		42,239,000
33	(amortization: < 12 months)					
34	URG Plant Regulatory Asset - noncurrent	944,805,000		407.4		944,805,000
35	(amortization: 22 years)					
36	URG Plant Regulatory Asset - Tax	183,010,953		182.3		183,010,953
37	(amortization: 11 years)					
38	Vegetation Management Reg. Asset - Current	15,848,080	163,110,849	400	156,874,793	22,084,136
39	(amortization: < 12 months)					
40	Wildfires Customer Protections Memo Acct - E		2,209,780	400		2,209,780
41	(amortization: > 12 months)					
42	Wildfires Customer Protections Memo Acct - G		1,579,497	400		1,579,497
43	(amortization: > 12 months)					
44	TOTAL	5,018,800,793	26,561,571,526		25,734,889,740	5,845,482,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Miscellaneous minor items	219,928,700	359,284,630	Various	579,094,281	119,049
3						
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43						
44	TOTAL	5,018,800,793	26,561,571,526		25,734,889,740	5,845,482,579

Schedule Page: 232.1 Line No.: 16 Column: b

The FERC software will not allow the entire beginning balance of Electric Balancing Account Reserve Account of ($3,707,101,106) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 16: ($999,999,999)
Line 17: ($999,999,999)
Line 18: ($999,999,999)
Line 19: ($707,101,109)
Total ($3,707,101,106)

Schedule Page: 232.1 Line No.: 16 Column: f

The FERC software will not allow the entire ending balance of Electric Balancing Account Reserve Account of ($4,384,871,477) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 16: ($999,999,999)
Line 17: ($999,999,999)
Line 18: ($999,999,999)
Line 19: ($999,999,999)
Line 20: ($251,031,475)
Line 21: ($133,840,006)
Total ($4,384,871,477)

Schedule Page: 232.1 Line No.: 19 Column: e

The FERC software will not allow the entire credit balance of Electric Balancing Account Reserve Account of ($1,426,738,895) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 19: $292,898,890
Line 20: $999,999,999
Line 21: $133,840,006
Total $1,426,738,895

Schedule Page: 232.3 Line No.: 3 Column: d

Primarily internal labor expenses. Offset to 182.3 - Other Regulatory Assets.

Schedule Page: 232.3 Line No.: 7 Column: d

Primarily internal labor expenses. Offset to 182.3 - Other Regulatory Assets, 549 - Misc. Other Power Generation Expenses and 253 - Other Deferred Credits.

Schedule Page: 232.5 Line No.: 2 Column: d

Primarily Wildfire Expense Memo Account-Electric, Wildfire Expense Memo Account-Gas and Transmission Integrity Management Balancing Account with offsets to 400.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Undistributed Charges	-10,756,425	1,138,612,174	VARIOUS	1,147,137,951	-19,282,202
2	Customer Adv for Construction	7,277,615	1,154,553	VARIOUS	776,326	7,655,842
3	Development Costs	62,235,288	2,661,177	131	19,283,495	45,612,970
4	Payments for MLX and					
5	Non-Energy Invoices	1,370,556	724,044,888	VARIOUS	724,006,244	1,409,200
6	Payments for Main Line					
7	Extension	-6,311,326	197,112,042	VARIOUS	202,297,724	-11,497,008
8	Clearing Account for					
9	JP Morgan Chase	1,271,127	23,841,842	VARIOUS	24,006,900	1,106,069
10	Payroll Clearing Account	201,506	12,670,981,026	VARIOUS	12,670,843,910	338,622
11	Land Surplus	480,219	559,044	930.2		1,039,263
12	Credit Card Clearing Account	-275,299	8,520,349	VARIOUS	7,963,968	281,082
13	Miscellaneous minor items	58,403	131,790,040	VARIOUS	132,439,144	-590,701
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	55,551,664				26,073,137

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	04/16/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: d

Typical Accounts charged: 131, 142

Schedule Page: 233 Line No.: 2 Column: d

Typical Accounts charged: 456, 495

Schedule Page: 233 Line No.: 5 Column: d

Typical Accounts charged: 131, 143

Schedule Page: 233 Line No.: 7 Column: d

Typical Accounts charged: 131, 252

Schedule Page: 233 Line No.: 9 Column: d

Typical Accounts charged: 131, 143, 559

Schedule Page: 233 Line No.: 10 Column: d

Typical Accounts charged: 131

Schedule Page: 233 Line No.: 12 Column: d

Typical Accounts charged: 131

Schedule Page: 233 Line No.: 13 Column: c

Activity primarily reflects undistributed cash receipts.

Schedule Page: 233 Line No.: 13 Column: d

Typical Accounts charged 182.3 and 236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Environmental	-93,803,083	-42,478,580
3	Compensation	94,297,980	50,033,114
4	CIAC	-146,286,875	-121,829,617
5	Injuries and Damages	102,846,333	3,478,176,873
6	California Corporation Franchise Tax	161,001,489	145,217,541
7	Other	-170,762,620	-437,277,748
8	TOTAL Electric (Enter Total of lines 2 thru 7)	-52,706,776	3,071,841,583
9	Gas		
10	Environmental	-57,056,261	-77,136,703
11	Compensation	45,329,183	36,918,182
12	CIAC	204,929,511	168,443,372
13	Injuries and Damages	-54,950,921	-39,315,702
14	California Corporation Franchise Tax	-26,584,707	-45,289,022
15	Other	1,223,174,711	1,372,702,830
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,334,841,516	1,416,322,957
17	Other (Specify)	446,026,682	537,426,086
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,728,161,422	5,025,590,626

Notes

Line 15 - Other

Amount primarily relates to net operating loss carryforwards.

Line 17 - Other	Balance at beginning of the year	Balance at end of the year
California Corporation Franchise Tax	(42,937,411)	(24,571,408)
Compensation	3,352,706	2,353,117
Other	485,611,387	559,644,377
Total	446,026,682	537,426,086

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Pacific Gas and Electri Company's stock			
2	is wholly owned by PG&E Corporation			
3	Common	800,000,000	5.00	
4				
5	TOTAL COMMON	800,000,000	5.00	
6				
7	Registered with the American Stock Exchange			
8	Preferred, Cumulative:			
9	Redeemable: WIthout Mandatory Redemption			
10	4.36%	418,291	25.00	25.75
11	4.50%	611,142	25.00	26.00
12	4.80%	793,031	25.00	27.25
13	5.00%	1,778,172	25.00	26.75
14	5.00% - Series A	934,322	25.00	26.75
15	7.04%	3,000,000	25.00	
16	Undesignated in Class	56,180,217	25.00	
17				
18	SubTotal Redeemable Without	63,715,175		
19	Mandatory Redemption			
20				
21	Registered with the American Stock Exchange			
22	Non-Redeemable			
23	5.00%	400,000	25.00	
24	5.50%	1,173,163	25.00	
25	6.00%	4,211,662	25.00	
26				
27	SubTotal Non-Redeemable	5,784,825		
28				
29	Redeemable: With Mandatory Redemption			
30	6.30%	2,500,000	25.00	
31	6.57%	3,000,000	25.00	
32	Undesignated in Class	10,000,000	100.00	
33				
34	SubTotal Redeemable With	15,500,000		
35	Mandatory Redemption			
36				
37	TOTAL PREFERRED	85,000,000		
38				
39				
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41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
264,374,809	1,321,874,045					3
						4
264,374,809	1,321,874,045					5
						6
						7
						8
						9
418,291	10,457,275					10
611,142	15,278,550					11
793,031	19,825,775					12
1,778,172	44,454,300					13
934,322	23,358,050					14
						15
						16
						17
4,534,958	113,373,950					18
						19
						20
						21
						22
400,000	10,000,000					23
1,173,163	29,329,075					24
4,211,662	105,291,550					25
						26
5,784,825	144,620,625					27
						28
						29
						30
						31
						32
						33
						34
						35
						36
10,319,783	257,994,575					37
						38
						39
						40
						41
						42

Schedule Page: 250 Line No.: 15 Column: a

Redeemed on August 31, 2005.

Schedule Page: 250 Line No.: 30 Column: a

This was reclassifed to Other Long-Term Debt in accordance with ASC 480 in September 2003. It was shown here since it is still part of the total number of preferred shares authorized. They were fully redeemed on May 31, 2005.

Schedule Page: 250 Line No.: 31 Column: a

This was reclassifed to Other Long-Term Debt in accordance with ASC 480 in September 2003. It was shown here since it is still part of the total number of preferred shares authorized. They were fully redeemed on May 31, 2005.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid in Capital	
2	Equity Infusions from Parent Company	6,729,587,624
3	Excess Tax Benefit on Stock Based Compensation	50,960,304
4		
5		
6		
7		
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40	TOTAL	6,780,547,928

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	25,143,083
2		
3	PREFERRED, CUMULATIVE:	
4	Redeemable - $25 par value per share:	
5	4.36%	29,509
6	4.50%	387,663
7	4.80%	777,999
8	5.00%	1,758,375
9	5.00% - Series A	158,204
10		
11	Non-Redeemable - $25 par value per share:	
12	5.00%	73,717
13	5.50%	173,730
14	6.00%	449,606
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	28,951,886

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)		Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221:			
2	SENIOR NOTES & POLLUTION CONTROL BONDS:			
3	Series	Rate		
4	Series 6.05% Senior Notes due 2034	6.050%	3,000,000,000	30,717,515
5				14,640,000 D
6	Series 5.80% Senior Notes due 2037	5.800%	700,000,000	6,807,234
7				3,822,000 D
8	Series 6.35% Senior Notes due 2038	6.350%	400,000,000	3,943,976
9				568,000 D
10	Series 8.25% Senior Notes due 2018	8.250%	600,000,000	4,572,075
11				9,942,000 D
12	Series 8.25% Senior Notes due 2018	8.250%	200,000,000	1,511,598
13				-8,950,000 P
14	Series 6.25% Senior Notes due 2039	6.250%	550,000,000	5,145,853
15				6,814,500 D
16	Series 5.4% Senior Notes due 2040	5.400%	550,000,000	5,435,842
17				7,815,500 D
18	Series 5.8% Senior Notes due 2037	5.800%	250,000,000	2,562,097
19				3,862,500 D
20	Series 3.5% Senior Notes due 2020	3.500%	550,000,000	4,205,770
21				2,728,000 D
22	Series 3.5% Senior Notes due 2020	3.500%	250,000,000	1,897,267
23				6,840,000 D
24	Series 5.4% Senior Notes due 2040	5.400%	250,000,000	2,459,767
25				6,252,500 D
26	Series 4.25% Senior Notes due 2021	4.250%	300,000,000	2,270,404
27				243,000 D
28	Series 3.25% Senior Notes due 2021	3.250%	250,000,000	1,981,515
29				1,312,500 D
30	Series 4.5% Senior Notes due 2041	4.50%	250,000,000	2,576,302
31				862,500 D
32	Series 4.45% Senior Notes due 2042	4.45%	400,000,000	4,062,665
33	TOTAL		19,232,100,000	271,215,110

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			2,036,000 D
2	Series 2.45% Senior Notes due 2022 2.45%	400,000,000	3,251,743
3			1,164,000 D
4	Series 3.75% Senior Notes due 2042 3.75%	350,000,000	3,632,775
5			311,500 D
6	Series 3.25% Senior Notes due 2023 3.25%	375,000,000	2,924,964
7			1,901,250 D
8	Series 4.6% Senior Notes due 2043 4.60%	375,000,000	3,768,714
9			303,750 D
10	Series 3.85% Senior Notes due 2023 3.85%	300,000,000	2,505,170
11			543,000 D
12	Series 5.125% Senior Notes due 2043 5.125%	500,000,000	5,099,524
13			765,000 D
14	Series 3.75% Senior Notes due 2024 3.75%	450,000,000	3,672,801
15			445,500 D
16	Series 4.75% Senior Notes due 2044 4.75%	450,000,000	4,685,300
17			1,921,500 D
18	Series 3.4% Senior Notes due 2024 3.40%	350,000,000	2,788,492
19			262,500 D
20	Series 4.75% Senior Notes due 2044 4.75%	225,000,000	2,298,853
21			-13,594,500 P
22	Series 4.3% Senior Notes due 2045 4.30%	500,000,000	5,051,799
23			5,745,000 D
24	Series 3.50% Senior Notes due 2025 3.50%	400,000,000	3,471,059
25			2,540,000 D
26	Series 4.30% Senior Notes due 2045 4.30%	100,000,000	1,092,707
27			5,231,000 D
28	Series 3.50% Senior Notes due 2025 3.50%	200,000,000	1,709,814
29			-2,716,000 P
30	Series 4.25% Senior Notes due 2046 4.25%	450,000,000	4,859,582
31			8,415,000 D
32	Series 2.95% Senior Notes due 2026 2.95%	600,000,000	5,241,785
33	TOTAL	19,232,100,000	271,215,110

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			1,596,000 D
2	Series 4.00% Senior Notes due 2046 4.00%	400,000,000	4,345,973
3			7,344,000 D
4	Series 4.00% Senior Notes due 2046 4.00%	200,000,000	2,102,746
5			4,136,000 D
6	Series 3.30% Senior Notes due 2027 3.30%	400,000,000	3,306,994
7			1,420,000 D
8	Series 3.30% Senior Notes due 2027 3.30%	1,150,000,000	9,322,742
9			3,404,000 D
10	Series 3.95% Senior Notes due 2047 3.95%	850,000,000	8,803,613
11			3,706,000 D
12	Series 4.25% Senior Notes due 2023 4.25%	500,000,000	4,061,237
13			1,175,000 D
14	Series 4.65% Senior Notes due 2028 4.65%	300,000,000	2,587,341
15			852,000 D
16			
17	Pollution Control Bonds		
18	1996 Series C/E/F Various	465,000,000	2,485,410
19	1997 Series B Various	148,550,000	886,179
20	2008 Series F-G Various	95,000,000	312,026
21	2009 Series A-B Various	148,550,000	806,484
22	2010 Series E 1.75%	50,000,000	328,903
23	SUBTOTAL ACCOUNT 221	19,232,100,000	271,215,110
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	19,232,100,000	271,215,110

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
3/23/04	3/1/34	3/23/04	3/1/34	3,000,000,000	181,500,000	4
						5
3/13/07	3/1/37	3/13/07	3/1/37	700,000,000	40,600,000	6
						7
3/3/08	2/15/38	3/3/08	2/15/38	400,000,000	25,400,000	8
						9
10/21/08	10/15/18	10/21/08	10/15/18		2,154,167	10
						11
11/18/08	10/15/18	11/18/08	10/15/18		2,154,167	12
						13
3/6/09	3/1/39	3/6/09	3/1/39	550,000,000	34,375,000	14
						15
11/18/09	1/15/40	11/18/09	1/15/40	550,000,000	29,700,000	16
						17
4/1/10	3/1/37	4/1/10	3/1/37	250,000,000	14,500,000	18
						19
9/15/10	10/1/20	9/15/10	10/1/20	550,000,000	19,250,000	20
						21
11/18/10	10/1/20	11/18/10	10/1/20	250,000,000	8,750,000	22
						23
11/18/10	1/15/40	11/18/10	1/15/40	250,000,000	13,500,000	24
						25
5/13/11	5/15/21	5/13/11	5/15/21	300,000,000	12,750,000	26
						27
9/12/11	9/15/21	9/12/11	9/15/21	250,000,000	8,125,000	28
						29
12/1/11	12/15/41	12/1/11	12/15/41	250,000,000	11,250,000	30
						31
4/16/2012	4/15/42	4/16/12	4/15/42	400,000,000	17,800,000	32
				18,387,100,000	791,084,121	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (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.
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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
8/16/12	8/16/22	8/16/12	8/16/22	400,000,000	9,800,000	2
						3
8/16/12	8/16/42	8/16/12	8/16/42	350,000,000	13,125,000	4
						5
6/14/13	6/15/23	6/14/13	6/15/23	375,000,000	12,187,500	6
						7
6/14/13	6/15/43	6/14/13	6/15/43	375,000,000	17,250,000	8
						9
11/12/13	11/15/23	11/12/13	11/15/23	300,000,000	11,550,000	10
						11
11/12/13	11/15/43	11/12/13	11/15/43	500,000,000	25,625,000	12
						13
2/21/14	2/15/24	2/21/14	2/15/24	450,000,000	16,875,000	14
						15
2/21/14	2/15/44	2/21/14	2/15/44	450,000,000	21,375,000	16
						17
8/18/14	8/15/24	8/18/14	8/15/24	350,000,000	11,900,000	18
						19
8/18/14	2/15/44	8/18/14	2/15/44	225,000,000	10,687,500	20
						21
11/6/14	3/15/45	11/6/14	3/15/45	500,000,000	21,500,000	22
						23
6/12/15	6/15/25	6/12/15	6/15/25	400,000,000	14,000,000	24
						25
6/12/15	3/15/45	6/12/15	3/15/45	100,000,000	4,300,000	26
						27
11/5/15	6/15/25	11/5/15	6/15/25	200,000,000	7,000,000	28
						29
11/5/15	3/15/46	11/5/15	3/15/46	450,000,000	19,125,000	30
						31
3/1/16	3/1/26	3/1/16	3/1/26	600,000,000	17,700,000	32
				18,387,100,000	791,084,121	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12/1/16	12/1/46	12/1/16	12/1/46	400,000,000	16,000,000	2
						3
3/10/2017	12/1/2046	3/10/2017	12/1/2046	200,000,000	8,000,000	4
						5
3/10/17	3/15/27	3/10/17	3/15/27	400,000,000	13,200,000	6
						7
11/29/17	12/1/27	11/29/17	12/1/27	1,150,000,000	37,950,000	8
						9
11/29/17	12/1/47	11/29/17	12/1/47	850,000,000	33,575,000	10
						11
8/6/2018	8/1/2023	8/6/2018	8/1/2023	500,000,000	8,559,028	12
						13
8/6/2018	8/1/2028	8/6/2018	8/1/2028	300,000,000	5,618,750	14
						15
						16
						17
5/23/96	11/1/26	5/23/96	11/1/26	465,000,000	6,176,618	18
9/16/97	11/1/26	9/16/97	11/1/26	148,550,000	2,047,926	19
6/15/17	Various	6/15/17	Various	50,000,000	1,308,124	20
9/1/09	11/1/26	9/1/09	11/1/26	148,550,000	1,965,341	21
6/15/17	11/1/26	6/15/17	11/1/26	50,000,000	875,000	22
				18,387,100,000	791,084,121	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				18,387,100,000	791,084,121	33

Schedule Page: 256 Line No.: 1 Column: c

Items included under column (c) represent original issuance expense, premium or discount on issuance related to outstanding debt which are recoverable through the cost of capital mechanism. Other financing related costs which are also recoverable are reflected on page 232, Other Regulatory Assets (Account 182.3).

Schedule Page: 256 Line No.: 10 Column: i

Interest expense is different from prior year due to the repayment of debt in February 2018 (2 months of interest expense).

Schedule Page: 256 Line No.: 12 Column: i

Interest expense is different from prior year due to the repayment of debt in February 2018 (2 months of interest expense).

Schedule Page: 256.2 Line No.: 4 Column: i

Interest expense is different from prior year due to debt being issued in March 2017 (10 months of interest expense).

Schedule Page: 256.2 Line No.: 6 Column: i

Interest expense is different from prior year due to debt being issued in March 2017 (10 months of interest expense).

Schedule Page: 256.2 Line No.: 8 Column: i

Interest expense is different from prior year due to debt being issued in November 2017 (1 month of interest expense).

Schedule Page: 256.2 Line No.: 10 Column: i

Interest expense is different from prior year due to debt being issued in November 2017 (1 month of interest expense).

Schedule Page: 256.2 Line No.: 12 Column: a

Refer to Note 6 on page 109, for CPUC authorization number and date.

Schedule Page: 256.2 Line No.: 14 Column: a

Refer to Note 6 on page 109, for CPUC authorization number and date.

Schedule Page: 256.2 Line No.: 20 Column: a

In December 2018, the Utility's $45 million principal amount of 1.05% Series 2008 G Pollution Control Bonds matured and were repaid.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	-6,818,107,469
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions In Aid of Construction	238,818,033
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	-2,278,988,662
11	Provision for State Income Taxes	-1,015,977,063
12	Per attached schedule (See page 261-1)	13,175,614,895
13		
14	Income Recorded on Books Not Included in Return	
15	AFUDC - Equity and debt	181,542,106
16	Balancing Accounts	536,745,233
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Per attached schedule (See page 261-1)	2,027,348,975
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	555,723,419
28	Show Computation of Tax:	
29	Federal Tax Net Income as above $	116,701,918
30	Tax at 21% for Electric, Water. Non-Utility, and Gas	
31	Other	
32	Add: Tax on FIN 48 Interest	298,573
33	Less: Research & Development Credits	-4,187,435
34	Less: Motor Vehicle Credit	-750,000
35	Foreign Tax Credit Adjustment Resuting From Specified Liability Losk	4,236,131
36	Utilization of Net Operating Loss Carryover	-104,000,477
37		
38	Subtotal Tax	12,298,710
39	FIN 48 Tax Adjustments (Net to Gross)	
40	Total Tax	12,298,710
41		
42	Federal Income Tax Accrual	12,298,710
43		
44		

Schedule Page: 261 Line No.: 12 Column: b

Annual Report of PACIFIC GAS AND ELECTRIC COMPANY
Year Ended December 31, 2018

Deductions recorded on books not deducted on return:		Tax addback
Executive Compensation		515,207
Compensation Related Adjustments		(11,830,175)
Penalties		5,334,520
NorCal Wildfires Reserve		11,991,045,840
Butte Fire Reserve		190,137,035
Meals & Entertainment & Lobbying		20,670,644
Capitalized Interest		70,563,501
Nuclear Fuel expense		125,886,538
GHG Allowances		465,459,803
DOE Settlement		21,462,460
Nuclear Decom Trust Book Expense		49,526,692
Loss on Reacquired Debt		3,897,598
DCPP Community Payment		134,462,115
Depreciation adjustment		107,513,189
Other		969,930
Total	$	13,175,614,895

Deductions on return not charged against book income:		Tax deduct
Computer Software		(109,723,336)
Bad Debts		(8,277,830)
Fossil Decommissioning		(20,833,379)
Earnings of Subsidiaries		(69,836)
Section 263A MSCM		(150,695,799)
Repairs		(1,568,837,037)
Property Tax & State Income Tax		(74,208,732)
Environmental Cleanup		(33,906,984)
Gas Hedge Amortization		(12,660,581)
Plant Disallowance		(48,135,460)
Total	$	(2,027,348,975)

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

See footnote in row 12, column (b)

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	Federal - FICA	12,206,965		96,230,144	103,781,479	
2	Federal - Taxes on Income	301,702,762		12,298,710	188,653	-4,236,129
3	Federal - Unemployment	3,874,854		1,077,997	5,007,018	
4	Federal - Decommisioning			33,367,070	33,367,070	
5						
6	SUBTOTAL FEDERAL	317,784,581		142,973,921	142,344,220	-4,236,129
7						
8	State - Taxes on Income	111,930,507		-16,339,589	59,269,453	10,164,738
9	State - Unemployment	90,611		8,068,926	8,053,559	
10						
11	SUBTOTAL STATE TAXES	112,021,118		-8,270,663	67,323,012	10,164,738
12						
13	Ad Valorem property	1,103		470,923,474	491,853,474	20,930,000
14	Other	3,589,980		23,184,765	27,047,777	
15						
16	SUBTOTAL OTHER TAXES	3,591,083		494,108,239	518,901,251	20,930,000
17						
18						
19						
20						
21						
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23						
24						
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35						
36						
37						
38						
39						
40						
41	TOTAL	433,396,782		628,811,497	728,568,483	26,858,609

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)	
4,655,630		65,141,285			31,088,859	1
309,576,690		4,236,133			8,062,577	2
-54,167		724,845			353,152	3
		33,367,070				4
						5
314,178,153		103,469,333			39,504,588	6
						7
46,486,203		112,005,442			-128,345,031	8
105,978		5,425,546			2,643,380	9
						10
46,592,181		117,430,988			-125,701,651	11
						12
1,103		355,073,218			115,850,256	13
-273,032		15,589,436			7,595,329	14
						15
-271,929		370,662,654			123,445,585	16
						17
						18
						19
						20
						21
						22
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						34
						35
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						40
360,498,405		591,562,975			37,248,522	41

Schedule Page: 262 Line No.: 1 Column: l

The following table is included to satisfy requirements for Form 1 and Form 2 reporting of this page:

	Gas (Account 408.1, 409.1) (a)	Non_utility (Account 408.2, 409.2) (b)	Total Other (c)
Federal - FICA*	31,088,859	0	31,088,859
Federal - Taxes on Income	1	8,062,576	8,062,577
Federal - Unemployment	353,152	0	353,152
Total Federal taxes	31,442,012	8,062,576	39,504,588
State - Taxes on Income	-98,535,431	-29,809,600	-128,345,031
State - Unemployment	2,643,380	0	2,643,380
Total State	-95,892,051	-29,809,600	-125,701,651
Ad Valorem property	115,363,512	486,744	115,850,256
Other	7,595,329	0	7,595,329
Total Other	122,958,841	486,744	123,445,585

*Adjustment reflects a portion of FICA taxes paid on construction work in progress. The amount charged during the year was reduced by the amount capitalized.

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

Adjustment relates to foreign tax credit reflected in column (d)

Schedule Page: 262 Line No.: 8 Column: f

Adjustments relates to FIN48

Schedule Page: 262 Line No.: 13 Column: f

Adjustment reflects a portion of property taxes paid on construction work in progress. The amount charged during the year was reduced and capitalized to certain assets under construction.

Schedule Page: 262 Line No.: 14 Column: a

Balances primarily includes City and County of San Francisco gross receipts and payroll taxes.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	93,325,105			411.5	4,652,206	
6							
7							
8	TOTAL	93,325,105				4,652,206	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	10%	20,708,685			411.5	997,701	
12							
13	TOTAL	20,708,685				997,701	
14							
15							
16							
17							
18							
19							
20							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
88,672,899	18		5
			6
			7
88,672,899			8
			9
			10
19,710,984	22		11
			12
19,710,984			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	CIAC Deferred Revenue	150,728,145	143, 146,456	51,059,826	67,340,832	167,009,151
2						
3	Deferred Cr - Electric Reserves	44,650,027	182, 232,926	1,405	2,087,504	46,736,126
4						
5	Other	12,716,162	Various	18,799,660	19,649,646	13,566,148
6						
7						
8						
9						
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14						
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35						
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39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	208,094,334		69,860,891	89,077,982	227,311,425

Schedule Page: 269 Line No.: 1 Column: a

Activity includes ~$42 million of amortization. The deferred credit is amortized over 30 years.

Schedule Page: 269 Line No.: 5 Column: a

"Other" consists of various other deferred credits amounts with balances of less than 5% of the year end balance (< 227,311,425 * 5% = 11,365,571).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6	Settlement Regulatory Asset	307		
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	307		
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)	307		
18	Classification of TOTAL			
19	Federal Income Tax	307		
20	State Income Tax			
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
						307	6
							7
						307	8
							9
							10
							11
							12
							13
							14
							15
							16
						307	17
							18
						307	19
							20
							21

NOTES (Continued)

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	5,866,193,157	-567,068,431	-246,450,716
3	Gas	1,477,659,791	-4,695,705	-142,021,557
4	Nonutility	50,526,203		
5	TOTAL (Enter Total of lines 2 thru 4)	7,394,379,151	-571,764,136	-388,472,273
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	7,394,379,151	-571,764,136	-388,472,273
10	Classification of TOTAL			
11	Federal Income Tax	5,790,140,411	-503,086,946	-260,939,801
12	State Income Tax	1,604,238,740	-68,677,189	-127,532,472
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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
					-624,198,615	4,921,376,827	2
					1,052,105,146	2,667,090,789	3
14,757,291	-153,745,799		-166,290,765			385,320,058	4
14,757,291	-153,745,799		-166,290,765		427,906,531	7,973,787,674	5
							6
							7
							8
14,757,291	-153,745,799		-166,290,765		427,906,531	7,973,787,674	9
							10
10,113,424	-153,512,599		-175,076,548		332,934,582	6,219,630,419	11
4,643,867	-233,200		8,785,783		94,971,948	1,754,157,255	12
							13

NOTES (Continued)

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

SFAS 109 adjustment and excess deferreds adjustment due to the fed rate change - account 254.

Schedule Page: 274 Line No.: 3 Column: j

SFAS 109 adjustment and excess deferreds adjustment due to the fed rate change - account 254.

Schedule Page: 274 Line No.: 4 Column: h

SFAS 109 adjustment and excess deferreds adjustment due to the fed rate change - account 254.

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Loss on Reacquired Debt	46,351,590	17,583,231	29,197,869
4	Balancing Accounts	142,447,428	25,734,058	-81,541,543
5	Other	2,495,951	1,741,064	-14,529,089
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	191,294,969	45,058,353	-66,872,763
10	Gas			
11	Loss on Reacquired Debt	21,963,589	5,789,837	11,015,454
12	Balancing Accounts	268,468,323	23,957,685	99,713,602
13				
14	Other	-2,161,432	597,013	98,562
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	288,270,480	30,344,535	110,827,618
18	OTHER	-31,348,386		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	448,217,063	75,402,888	43,954,855
20	Classification of TOTAL			
21	Federal Income Tax	393,514,962	20,436,820	40,112,798
22	State Income Tax	54,702,101	54,966,068	3,842,057
23	Local Income Tax			

NOTES

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

ACCUMULATED 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
						34,736,952	3
					102,489,643	352,212,672	4
						18,766,104	5
							6
							7
							8
					102,489,643	405,715,728	9
							10
						16,737,972	11
					25,112,667	217,825,073	12
							13
						-1,662,981	14
							15
							16
					25,112,667	232,900,064	17
11,307,727	1,458,408					-21,499,067	18
11,307,727	1,458,408				127,602,310	617,116,725	19
							20
11,310,245	1,458,408				41,843,093	425,533,914	21
-2,518					85,759,217	191,582,811	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 4 Column: j

FERC Form 1 Pages 276-277
Dec. 31,
2018
Detail of Adjustments
Debit
(Credit)

[A]	(102,489,643)	Excess deferred adjustments due to change in fed tax rate - account 254
[B]	(25,112,667)	Excess deferred adjustments due to change in fed tax rate - account 254

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	CA Energy Systems 21st Centur B/A Elect NC	(308,024)	182.3	3,536,524	3,460,596	-383,952
2	(amortization: 5 years)					
3	California Solar Initiative	66,414,573	400	14,016,129	9,220,917	61,619,361
4	(amortization: 5 years)					
5	Demand Response Expenditures Balancing Account	57,642,744	400	69,069,154	51,492,499	40,066,089
6	Distribution Resource Plan Demo B/A Curr	107,978	400	235,686	1,067,647	939,939
7	(amortization: <12 months)					
8	DREBA Operations Balancing Account - Current	24,840,637	400	25,169,788	12,458,361	12,129,210
9	Electric Vehicle Program BA Current	(1,972,297)	400	13,432,047	18,915,509	3,511,165
10	(amortization: <12 months)					
11	Electric Price Risk Management - Current	26,867,115	555	104,655,510	120,740,007	42,951,612
12	Electric Price Risk Management - NonCurrent	101,500,411	555	375,684,882	439,345,727	165,161,256
13	Electric Program Investment Charge Balancing Acct	173,193,908	400	90,142,787	106,454,386	189,505,507
14	Engineering Critical Assessment Bal ACCT-CURRENT		400	9,848,830	73,668,433	63,819,603
15	(amortization: <12 months)					
16	FAS 109 Reg Liability	1,020,833,435	400	5,397,386,422	4,660,041,025	283,488,038
17	(amortization: >12 months)					
18	FAS 143 Regulatory Liability - Nuclear	(999,999,999)	Various			-999,999,999
19	FAS 143 Regulatory Liability - Nuclear	(574,459,931)		254,460,135	136,957,777	-691,962,289
20	FAS 143 Regulatory Liability - Fossil	(132,024,941)	Various	13,861,210		-145,886,151
21	FAS 143 Regulatory Liability - Fossil Decomm	176,633,546	228.4	7,769,312		168,864,234
22	FAS 143 Regulatory Liability-Nuclear Decomm	2,863,247,225	128	588,388,705	454,862,836	2,729,721,356
23	FIN 47 Regulatory Liability	(709,047,472)	Various	580,609,698	584,794,371	-704,862,799
24	Gas PPP Surcharge-RDD	(398,165)	400	12,095,232	12,058,377	-435,020
25	(amortization: <12 months)					
26	Gas Price Risk Management - Current	376,079	807	9,427,335	9,504,259	453,003
27	GHGRBA - Greenhouse Gas Revenue Subaccount	89,838,359	400	464,936,605	348,977,027	-26,121,219
28	(amortization: <12 months)					
29	GHGRBA - Low Carbon Fuels Stnd Rev Subaccount	18,626,564	400	17,572,385	61,611,607	62,665,786
30	(amortization: <12 months)					
31	GPBA - Greenhouse Gas Revenue Subaccount	222,829,867	400	331,869,052	109,298,352	259,167
32	(amortization: <12 months)					
33	GPBA - Low Carbon Fuels Stnd Rev Subaccount	685,998	400	443,920	391,047	633,125
34	(amortization: <12 months)					
35	Miscellaneous Electric Reg Liab - Current	80,613,478	449	99,581,295	343,955,376	324,987,559
36	(amortization: <12 months)					
37	Miscellaneous Electric Reg Liab - NonCurrent	245,025,521	549	50,428,889	355,395,957	549,992,589
38	MISCELLANEOUS GAS REG LIAB - CURRENT	9	495	61,085,215	101,987,163	40,901,957
39	Amortization : <12 MONTHS					
40	MISCELLANEOUS GAS REG LIAB - NONCURRENT	19,026,468	549	6,158,348	3,382,670	16,250,790
41	TOTAL	3,876,105,498		10,770,418,583	10,391,095,332	3,496,782,247

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Amortization : 2 YEARS					
2	NATIONAL GAS LEAK ABATEMENT PROGRAM		400	1,145,007	2,166,870	1,021,863
3	(amortization: < 12 months)					
4	NON CURRENT REG LIAB-CC8 SETTLEMENT	46,856,179	108	2,260,506		44,595,673
5	(amortization: < 12 months)					
6	Amortization : 25 YEARS					
7	NON-TARIFFED PRODUCTS AND SVCS BA-ELECTRIC	321,567	182.3	2,434,436	2,688,612	575,743
8	Amortization : < 12 MONTHS					
9	NON-TARIFFED PRODUCTS AND SVCS BA-GAS	262,995	182.3	304,707	511,842	470,130
10	Amortization : < 12 MONTHS					
11	ON BILL FINANCING BALANCING ELECTRIC	44,053,920	930.2	13,595,803	12,413,062	42,871,179
12	ON BILL FINANCING BALANCING GAS	9,541,493	930.2	2,589,677	2,387,522	9,339,338
13	PPP (PPPLIBA)-ELECTRIC	161,760,083	400	77,081,759	88,351,838	173,030,162
14	Amortization : < 12 MONTHS					
15	PPP (PPPLIBA)-GAS	57,115,769	400	59,190,195	79,331,373	77,256,947
16	Amortization : < 12 MONTHS					
17	PPP ENERGY EFFICIENCY-GAS	3,523,260	400	1,368,582	329,218	2,483,896
18	PPP SURCHARGE ENERGY EFFICIENCY - GAS	6,165,082	400	97,896,209	90,617,259	-1,113,868
19	Amortization : < 12 MONTHS					
20	PPP SURCHARGE LOW INCOME - GAS	(8,697,021)	400	79,311,319	80,449,644	-7,558,696
21	Amortization : < 12 MONTHS					
22	PPP SURCHARGE RDD - CURRENT	3,589,636	182.3	11,069,274	11,097,731	3,618,093
23	Amortization : < 12 MONTHS					
24	PROCUREMENT ENERGY EFFICIENCY	15,108,043	400	6,234,784	1,480,986	10,354,245
25	PROCUREMENT ENERGY EFFICIENCY BALANCING	121,365,565	400	363,403,980	447,494,954	205,456,539
26	Amortization : <12 MONTHS					
27	PUBL PURP PROG ENERGY EFFICIENCY BAL ACCT -	24,615,780	400	78,711,291	94,747,059	40,651,548
28	Amortization : <12 MONTHS					
29	REG LIABILITY GAS RISK MGMT - NONCURRENT	629,984	807	797,660	306,342	138,666
30	REG LIABILITY-MISC ELEC CURRENT -FERC INTEREST		400	1,686	74,837,561	74,835,875
31	Amortization : <12 MONTHS					
32	REGULATORY LIABILITY RETIREM	418,061,715	520	34,704,994	37,298,481	420,655,202
33	Amortization : INDEFINITE					
34	RULE 20A BALANCING ACCOUNT (RBA) NONCURRENT		400	18,110,041	11,472,486	-6,637,555
35	Amortization : > 12 MONTHS					
36	SELF GENERATION PROGARM-GAS	35,020,030	400	5,040,192	13,822,471	43,802,309
37	SELF GENERATION PROGRAM - ELECTRIC	180,387,537	400	22,960,873	63,388,316	220,814,980
38	SOLAR ON MULTIFAMILY AFFORDABLE HOUSING BAL		400		51,081,839	51,081,839
39	Amortization : < 12 MONTHS					
40	SW MARKETING, EDUCATION AND OUTREACH	4,349,169	400	14,652,489	11,904,138	1,600,818
41	TOTAL	3,876,105,498		10,770,418,583	10,391,095,332	3,496,782,247

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Amortization : < 12 MONTHS					
2	SW MARKETING, EDUCATION AND OUTREACH	755,732	400	1,620,822	1,321,828	456,738
3	Amortization : < 12 MONTHS					
4	TAMA - GAS	(64,490,315)	182.3	36,799,024		-101,289,339
5	Amortization : 2 YEARS					
6						
7	Miscellanous minor items	45,716,209	Various	1,237,268,178	1,191,551,974	5
8						
9						
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30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,876,105,498		10,770,418,583	10,391,095,332	3,496,782,247

Schedule Page: 278 Line No.: 18 Column: b

The FERC software will not allow the entire beginning balance of FAS 143 Regulatory Liability of ($1,574,459,929) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 18:	($999,999,999)
Line 19:	($574,459,930)
Total	($1,574,459,929)

Schedule Page: 278 Line No.: 18 Column: c

Offset to account 108 - Accumulated Depreciation, and 230 - ARO - Liability.

Schedule Page: 278 Line No.: 18 Column: f

The FERC software will not allow the entire ending balance of FAS 143 Regulatory Liability of ($1,691,962,287) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 18:	($999,999,999)
Line 19:	($691,962,288)
Total	($1,691,962,287)

Schedule Page: 278 Line No.: 23 Column: c

Offset to account 108 - Accumulated Depreciation, and 230 - ARO - Liability.

Schedule Page: 278.2 Line No.: 7 Column: c

Activity primarily related to SH FUNDED GAS TRANS SAFETY ACCOUNT offset to 182.3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	5,051,462,029	5,693,009,418
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	6,141,452,151	6,499,737,292
5	Large (or Ind.) (See Instr. 4)	1,531,576,710	1,603,479,860
6	(444) Public Street and Highway Lighting	63,885,241	69,800,620
7	(445) Other Sales to Public Authorities	2,263,228	2,175,010
8	(446) Sales to Railroads and Railways	6,151,562	6,988,161
9	(448) Interdepartmental Sales	46,634,494	44,421,522
10	TOTAL Sales to Ultimate Consumers	12,843,425,415	13,919,611,883
11	(447) Sales for Resale	326,502,665	112,554,619
12	TOTAL Sales of Electricity	13,169,928,080	14,032,166,502
13	(Less) (449.1) Provision for Rate Refunds	580,325,469	169,512,710
14	TOTAL Revenues Net of Prov. for Refunds	12,589,602,611	13,862,653,792
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,139,504	5,496,959
17	(451) Miscellaneous Service Revenues	9,362,424	9,650,326
18	(453) Sales of Water and Water Power	3,683,870	3,621,831
19	(454) Rent from Electric Property	104,364,515	86,527,942
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-262,517,205	-343,369,626
22	(456.1) Revenues from Transmission of Electricity of Others	1,845,837	2,830,782
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(400) Balancing Accounts	635,580,851	-343,783,254
26	TOTAL Other Operating Revenues	496,459,796	-579,025,040
27	TOTAL Electric Operating Revenues	13,086,062,407	13,283,628,752

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
27,485,186	29,408,850	4,798,731	4,808,753	2
				3
36,430,669	36,881,436	635,503	634,978	4
15,163,358	15,187,122	1,314	1,325	5
306,682	327,380	36,204	34,795	6
12,790	12,177	2	13	7
377,019	407,351	23	25	8
290,560	289,607			9
80,066,264	82,513,923	5,471,777	5,479,889	10
10,790,942	5,661,727			11
90,857,206	88,175,650	5,471,777	5,479,889	12
				13
90,857,206	88,175,650	5,471,777	5,479,889	14

Line 12, column (b) includes $ -1,586,893 of unbilled revenues.

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

Schedule Page: 300 Line No.: 4 Column: b

Line 4 includes all other commercial and industrial customers including irrigation pumping.

Schedule Page: 300 Line No.: 4 Column: c

Line 4 includes all other commercial and industrial customers including irrigation pumping.

Schedule Page: 300 Line No.: 5 Column: b

Line 5 includes commercial and industrial customers with demands of 1,000 Kw or greater.

Schedule Page: 300 Line No.: 5 Column: c

Line 5 includes commercial and industrial customers with demands of 1,000 Kw or greater.

Schedule Page: 300 Line No.: 10 Column: b

Column (b) includes California Department of Water Resources ("DWR") revenues of $410,485,871 which was deducted from Line 21 below.

Schedule Page: 300 Line No.: 10 Column: c

Column (b) includes California Department of Water Resources ("DWR") revenues of $315,481,524 which was deducted from Line 21 below.

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

This consists of :

1	NSF fees and rent charges to customers' refundable deposits	1,510,591
2	NRD Revenue	2,501,467
3	MLX billings to electric residential customers	3,271,478
4	MLX billings to electric non-residential customers	927,612
5	Reimbursable third-party labor requested on behalf of customers	1,151,276
	Total	9,362,424

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

This consists of :

NSF fees and rent charges to customers' refundable deposits	1,682,640
NRD Revenue	2,746,217
MLX billings to electric residential customers	3,199,430
MLX billings to electric non-residential customers	1,024,123
Reimbursable third-party labor requested on behalf of customers	997,916
Total	

9,650,326

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

This consists of :

Unbilled revenues	(1,586,893)
Reimbursement to the Utility for costs spent on customer projects	26,889,727
Reimbursement to the Utility for costs spent on customer billing	7,448,792
Reimbursement fees paid to the CPUC based on sales	(36,570,942)
Employee transfer fees	341,127
Other revenue-damage claim	2,321,285
Recreational Facilities Revenue	1,402,622
Revenue assigned - base	(23,988,441)
Pass-through franchise fees and uncollectible revenue	23,988,441
Transition Cost Revenue Account for non-bypassable charges	38,531,280
Fees for utility energy service contracts	51,290,247
Other electric revenues not classified elsewhere	57,148,118
MCI rights of way	691,661
DWR	(410,485,871)
Miscellaneous (items under $250,000)	61,641
Total	(262,517,206)

The DWR revenues of $410,485,871 represents amount passed through to the DWR. The Utility acts as a pass-through entity for DWR charges collected from the Utility's customers. Although charges for the DWR are included in total electric revenues, the Utility deducts pass through amounts from electric revenues. These pass-through revenues are excluded from the Utility's electric revenues in its Statement of Income.

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

This consists of :

Unbilled revenues	(75,837,834)
Reimbursement to the Utility for costs spent on customer projects	50,772,932
Reimbursement to the Utility for costs spent on customer billing	5,342,943
Reimbursement fees paid to the CPUC based on sales	(34,903,166)
Employee transfer fees	2,649,724
Other revenue-damage claim	1,699,240
Recreational Facilities Revenue	1,249,347
Revenue assigned - base	(21,785,055)
Pass-through franchise fees and uncollectible revenue	21,785,055
Transition Cost Revenue Account for non-bypassable charges	33,987,442
Fees for utility energy service contracts	29,088,601
Other electric revenues not classified elsewhere	52,392,084
MCI rights of way	691,661
DWR	(410,341,937)
Miscellaneous (items under $250,000)	117,981
Total	(343,090,982)

The DWR revenues of $410,341,937 represents amount passed through to the DWR. The Utility acts as a pass-through entity for DWR charges collected from the Utility's customers. Although charges for the DWR are included in total electric revenues, the Utility deducts pass through amounts from electric revenues. These pass-through revenues are excluded from the Utility's electric revenues in its Statement of Income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	NONE				
2					
3					
4					
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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	440 Residential Sales:					
2	E1 Individually Metered	17,536,596	3,579,290,436	3,260,752	5,378	0.2041
3	EL1 Residential Care Program S	6,516,017	811,459,315	1,104,132	5,901	0.1245
4	E6 Residential Time-of-Use Servic	413,028	85,107,830	91,148	4,531	0.2061
5	EL6 Residential Care Time-of-U	34,294	4,244,198	5,863	5,849	0.1238
6	E7 Time-of-Use	-22	-3,366	-4	5,500	0.1530
7	EL7 Residential Care Program T		-2			
8	E8 Seasonal Service Option	-151	-43,600	-1	151,000	0.2887
9	EL8 Residential Seasonal Care	-20	-3,490			0.1745
10	ETOUA Residential Time-of-Use Ser	436,367	98,086,586	120,799	3,612	0.2248
11	EL-TOUA Residential Care Time-of-	77,881	9,086,571	16,774	4,643	0.1167
12	ETOUB Residential Time-of-Use Ser	614,416	135,391,113	50,137	12,255	0.2204
13	EL-TOUB Residential Care Time-of-	88,230	11,543,587	8,776	10,054	0.1308
14	ETOUC Residential Time-of-Use Ser	400,015	93,699,020	64,638	6,189	0.2342
15	EL-TOUC Residential Care Time-of-	48,514	5,983,417	10,268	4,725	0.1233
16	ETOUP Residential Time-of-Use Ser	1	63			0.0630
17	EA9 Experimental TOU Service for					
18	EB9 Experimental TOU Service for		-18			
19	ECLSD		752			
20	EVA Residential TOU Service for P	644,051	112,516,469	45,594	14,126	0.1747
21	EVB Residential TOU Service for P	1,308	189,092	426	3,070	0.1446
22	EM Master-Metered Multi-family Se	211,513	39,491,286	15,939	13,270	0.1867
23	EML Multifamily CARE Program - Ma	26,273	3,049,414	182	144,357	0.1161
24	EMTOU Residential Time of Use Ser	1,079	448,975	287	3,760	0.4161
25	ES Multi-family Service	24,341	3,811,479	281	86,623	0.1566
26	ESL Multifamily CARE Program Serv	26,656	3,821,936	287	92,878	0.1434
27	ESR RV Park and Residential Marin	1,810	325,544	24	75,417	0.1799
28	ESRL RV Park and Residential Mari	8,702	1,358,660	85	102,376	0.1561
29	ET Mobilehome Park Service	14,344	2,157,266	251	57,147	0.1504
30	ETL Low-Income Mobile Home	357,532	50,007,682	2,065	173,139	0.1399
31	MIS-RS	44	18			0.0004
32	SE1 Standby - Individually Metere	107	23,706	4	26,750	0.2216
33	SEM1 Standby - Master-Metered Mul	2,260	361,345	10	226,000	0.1599
34	STOUS Standby - TOU Secondary -		56,745	14		
35	UNCLASSIFIED					
36	Total Residential	27,485,186	5,051,462,029	4,798,731	5,728	0.1838
37						
38						
39						
40						
41	TOTAL Billed	80,066,264	13,169,928,080	5,471,777	14,633	0.1645
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	80,066,264	13,169,928,080	5,471,777	14,633	0.1645

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	442 Commercial and Industrial Sal					
4	A1 Small General Service	1,062,816	195,948,995	46,613	22,801	0.1844
5	A1F Small General Service	71,322	15,595,784	17,439	4,090	0.2187
6	A1X Small General Service	5,651,396	1,166,006,444	369,060	15,313	0.2063
7	A15 Small General Service	446	247,635	396	1,126	0.5552
8	A6 Time-of-Use	1,339,517	260,231,066	26,662	50,241	0.1943
9	A10 Medium General	8,431,271	1,449,532,884	43,336	194,556	0.1719
10	E19 500 to 999 Kw Demand	13,389,196	1,780,218,556	28,022	477,810	0.1330
11	E20 1000 Kw Demand or More	13,229,175	1,300,572,321	1,013	13,059,403	0.0983
12	E37 1000 Kw Demand or More	24,413	2,813,007	27	904,185	0.1152
13	AG1 Agricultural Power	78,531	22,137,091	4,617	17,009	0.2819
14	AG4 TOU Agricultural Power	1,244,290	339,525,584	54,970	22,636	0.2729
15	AG5 Large TOU Agricultural Power	4,871,556	853,210,492	27,401	177,788	0.1751
16	AGICE Agricultural Internal Combu	5,249	702,053	117	44,863	0.1337
17	AGR Split-Wk TOU Agricultural Pow	38,611	10,469,135	1,958	19,720	0.2711
18	AGV Short-Pk TOU Agricultural Pow	31,230	7,743,085	1,300	24,023	0.2479
19	MIS-RS	4	-3,029			-0.7573
20	OL1 Outdoor Area Lighting Service	8,978	2,649,296	13,024	689	0.2951
21	SA1 Standby & General Service	88	20,618	5	17,600	0.2343
22	SA6 Standby & Small TOU	-8,111	1,397,130	18	-450,611	-0.1723
23	SA10 Standby & Alt. Rate for Med-	14,014	2,043,821	24	583,917	0.1458
24	SE19 Standby & 500 to 999 Kw	108,088	16,702,169	73	1,480,658	0.1545
25	SE20 Standby & 1000 Kw Demand	1,543,627	166,833,988	94	16,421,564	0.1081
26	SE37 Standby - Med Gen	25,004	3,273,616	1	25,004,000	0.1309
27	STOUP Standby - TOU Primary	16,379	10,474,652	232	70,599	0.6395
28	STOUS Standby - TOU Secondary -	2,091	2,469,785	154	13,578	1.1812
29	STOUT Standby - TOU Transformer	413,987	62,152,276	260	1,592,258	0.1501
30	UNCLASSIFIED	859	60,407	1	859,000	0.0703
31						
32						
33						
34	Total Commercial and Industrial	51,594,027	7,673,028,861	636,817	81,019	0.1487
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	80,066,264	13,169,928,080	5,471,777	14,633	0.1645
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	80,066,264	13,169,928,080	5,471,777	14,633	0.1645

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4	444 Public Street and Highway Lig					
5	LS1-A Utility-Owned Street & High	13,501	8,198,329	5,739	2,353	0.6072
6	LS1-B Utility-Owned Street & High	27	7,016	6	4,500	0.2599
7	LS1-C Utility-Owned Street & High	4,548	2,686,673	546	8,330	0.5907
8	LS1-D Utility-Owned Street & High	7,777	3,341,493	1,024	7,595	0.4297
9	LS1-E Utility-Owned Street & High	9,129	8,001,758	1,745	5,232	0.8765
10	LS1-F Utility-Owned Street & High	4,368	2,529,399	1,627	2,685	0.5791
11	LS2-A Customer-Owned Street & Hig	214,319	29,083,083	9,382	22,844	0.1357
12	LS2-C Customer-Owned Street & Hig	1,945	457,139	392	4,962	0.2350
13	LS3 Cust-Owned Street & Highway L	7,915	1,134,781	1,403	5,641	0.1434
14	LS3-F Cust-Owned Street & Highway	4,017	663,555	2,167	1,854	0.1652
15	TC1 Traffic Control Service	37,945	7,531,226	11,591	3,274	0.1985
16	TC1F Traffic Control Service	1,191	250,789	582	2,046	0.2106
17						
18	Total Public Street and Highway	306,682	63,885,241	36,204	8,471	0.2083
19						
20	445 Other Sales to Public Authori					
21	Special Contracts	12,790	2,263,228	2	6,395,000	0.1770
22	Total Other Sales to Public Aut	12,790	2,263,228	2	6,395,000	0.1770
23						
24	446 Sales to Railroads and Railwa					
25	Special Contracts	377,019	6,151,562	23	16,392,130	0.0163
26	Total Sales to Railroads and Ra	377,019	6,151,562	23	16,392,130	0.0163
27						
28	448 Interdepartmental Sales	290,560	46,634,494			0.1605
29	Total Interdepartmental Sales	290,560	46,634,494			0.1605
30						
31	Total Sales to					
32	Ultimate Consumers					
33						
34	447 Sales for Resale					
35	Special Contracts		326,502,665			
36						
37						
38						
39						
40						
41	TOTAL Billed	80,066,264	13,169,928,080	5,471,777	14,633	0.1645
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	80,066,264	13,169,928,080	5,471,777	14,633	0.1645

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RQ Sales:					
2	Silicon Valley Power	RQ	248	0.4	17.7	17.7
3		RQ	114	0.0	0.0	0.0
4	California Independent System Operator	RQ	6	N/A	N/A	N/A
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**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
1,843	1,071	39,544		40,615	2
					3
10,789,099		344,976,739	-18,514,689	326,462,050	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
10,790,942	1,071	345,016,283	-18,514,689	326,502,665	
0	0	0	0	0	
10,790,942	**1,071**	**345,016,283**	**-18,514,689**	**326,502,665**	

Schedule Page: 310 Line No.: 2 Column: a

- Sales represent the Grizzly Power Sale.
- Silicon Valley Power was formally the City of Santa Clara.

The Rate Schedule for Grizzly was changed in FERC Docket No. ER17-1752-000.

Schedule Page: 310 Line No.: 3 Column: a

The ETC between PG&E and CCSF terminated on July 1, 2015, pursuant to Section 9.26.2 of the CCSF Interconnection Agreement (IA), Rate Schedule FERC No. 114.

Schedule Page: 310 Line No.: 4 Column: a

Represents amounts included in ISO Settlement Statement on page 397.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	55,323	1,413
5	(501) Fuel	207,064,898	176,832,878
6	(502) Steam Expenses	16,174	10,249
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	388,314	651,480
11	(507) Rents		
12	(509) Allowances	35,626,112	27,272,848
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	243,150,821	204,768,868
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	129,982	17,771
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant	1,478,290	1,669,805
18	(513) Maintenance of Electric Plant	19,232,845	-11,150,358
19	(514) Maintenance of Miscellaneous Steam Plant	1,691,099	4,324,333
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,532,216	-5,138,449
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	265,683,037	199,630,419
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	4,025,966	6,147,760
25	(518) Fuel	129,114,087	124,868,867
26	(519) Coolants and Water	37,292,499	30,611,193
27	(520) Steam Expenses	38,815,499	38,190,638
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	1,867,685	1,998,438
31	(524) Miscellaneous Nuclear Power Expenses	338,894,022	164,674,710
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	550,009,758	366,491,606
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	2,782,594	3,239,200
36	(529) Maintenance of Structures	3,442,055	1,104,975
37	(530) Maintenance of Reactor Plant Equipment	26,816,759	29,240,710
38	(531) Maintenance of Electric Plant	36,172,375	42,948,466
39	(532) Maintenance of Miscellaneous Nuclear Plant	-83,619,837	57,119,138
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	-14,406,054	133,652,489
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	535,603,704	500,144,095
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	448,001	2,199,949
45	(536) Water for Power	2,190,879	2,128,801
46	(537) Hydraulic Expenses	1,449,339	1,317,581
47	(538) Electric Expenses	26,715,623	29,079,473
48	(539) Miscellaneous Hydraulic Power Generation Expenses	60,364,066	65,379,284
49	(540) Rents	796,739	785,420
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	91,964,647	100,890,508
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,648,157	2,542,935
54	(542) Maintenance of Structures	2,122,736	5,802,047
55	(543) Maintenance of Reservoirs, Dams, and Waterways	23,269,718	35,462,156
56	(544) Maintenance of Electric Plant	19,942,182	21,197,455
57	(545) Maintenance of Miscellaneous Hydraulic Plant	5,923,153	8,679,202
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	52,905,946	73,683,795
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	144,870,593	174,574,303

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	593,029	186,426
63	(547) Fuel		
64	(548) Generation Expenses	10,644,381	11,035,728
65	(549) Miscellaneous Other Power Generation Expenses	939,016	-3,161,565
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	12,176,426	8,060,589
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	161,732	59,192
70	(552) Maintenance of Structures	2,848,377	2,735,312
71	(553) Maintenance of Generating and Electric Plant	7,166,782	5,487,309
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	5,692,471	2,924,933
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	15,869,362	11,206,746
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	28,045,788	19,267,335
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	3,496,844,586	3,852,611,625
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	314,924,584	277,460,451
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	3,811,769,170	4,130,072,076
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	4,785,972,292	5,023,688,228
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,738,383	2,652,100
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	32,099,953	28,980,843
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	23,000,855	26,125,073
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	8,859,349	10,285,155
93	(562) Station Expenses	7,988,173	6,400,713
94	(563) Overhead Lines Expenses	13,924,543	6,577,810
95	(564) Underground Lines Expenses	180,771	1,495,308
96	(565) Transmission of Electricity by Others	949,485	13,665,066
97	(566) Miscellaneous Transmission Expenses	99,690,874	83,829,810
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	192,432,386	180,011,878
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,184,331	832,264
102	(569) Maintenance of Structures	703,947	645,279
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	22,519,226	21,874,666
108	(571) Maintenance of Overhead Lines	129,824,961	96,349,282
109	(572) Maintenance of Underground Lines	1,699,411	192,100
110	(573) Maintenance of Miscellaneous Transmission Plant	725,484	1,070,803
111	TOTAL Maintenance (Total of lines 101 thru 110)	156,657,360	120,964,394
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	349,089,746	300,976,272

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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	13,832,809	14,650,908
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	13,832,809	14,650,908
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)	13,832,809	14,650,908
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,428,597	4,382,277
135	(581) Load Dispatching		
136	(582) Station Expenses	2,238,385	2,196,251
137	(583) Overhead Line Expenses	30,749,818	20,503,087
138	(584) Underground Line Expenses	30,333,882	30,005,042
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	1,646,498	1,691,253
141	(587) Customer Installations Expenses	15,512,197	14,004,409
142	(588) Miscellaneous Expenses	240,620,319	37,055,570
143	(589) Rents	666,513	78,291
144	TOTAL Operation (Enter Total of lines 134 thru 143)	324,196,209	109,916,180
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,165,788	4,493,803
147	(591) Maintenance of Structures	2,824,259	2,542,906
148	(592) Maintenance of Station Equipment	26,624,095	26,724,342
149	(593) Maintenance of Overhead Lines	751,642,765	528,832,572
150	(594) Maintenance of Underground Lines	38,420,026	41,892,183
151	(595) Maintenance of Line Transformers	1,817,300	2,125,962
152	(596) Maintenance of Street Lighting and Signal Systems	1,738,254	2,056,782
153	(597) Maintenance of Meters	7,806,252	7,058,358
154	(598) Maintenance of Miscellaneous Distribution Plant	733,849	680,573
155	TOTAL Maintenance (Total of lines 146 thru 154)	832,772,588	616,407,481
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	1,156,968,797	726,323,661
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	6,941,089	12,819,397
160	(902) Meter Reading Expenses	5,761,047	6,183,670
161	(903) Customer Records and Collection Expenses	163,431,605	156,058,369
162	(904) Uncollectible Accounts	26,821,384	42,122,468
163	(905) Miscellaneous Customer Accounts Expenses	-675,994	-1,226,397
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	202,279,131	215,957,507

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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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	442,540,037	512,432,586
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	404,461	471,252
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	442,944,498	512,903,838
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	961,730	1,194,885
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	961,730	1,194,885
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	216,675,790	304,370,923
182	(921) Office Supplies and Expenses	-10,731,390	55,729,129
183	(Less) (922) Administrative Expenses Transferred-Credit	36,224,106	50,102,503
184	(923) Outside Services Employed	276,922,321	162,252,920
185	(924) Property Insurance	10,118,251	14,161,414
186	(925) Injuries and Damages	12,202,690,726	190,423,721
187	(926) Employee Pensions and Benefits	273,560,929	384,675,276
188	(927) Franchise Requirements	89,640,572	102,108,129
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		121,950
192	(930.2) Miscellaneous General Expenses	11,017,410	6,306,443
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	13,033,670,503	1,170,047,402
195	Maintenance		
196	(935) Maintenance of General Plant	4,725,363	8,482,612
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	13,038,395,866	1,178,530,014
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	19,990,444,869	7,974,225,313

Schedule Page: 320 Line No.: 76 Column: b

Of the year end balance, ($220,207) relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 76 Column: c

Of the year end balance, $204,601 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: b

Of the year end balance, $0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: c

Of the year end balance, $0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: b

Of the quarter end balance, $0 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: c

Of the quarter end balance, $0 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: b

Of the quarter end balance, $0 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: c

Of the quarter end balance, $693 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: b

Of the quarter end balance, $185,192 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: c

Of the quarter end balance, $196,979 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: b

Of the quarter end balance, $0 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: c

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	QUALIFYING FACILITIES (QF's)			0.00000	0.00000	
2	RENEWABLES:			0.00000	0.00000	
3	BIOGAS-CITY OF WATSONVILLE	LU		0.00000	0.05920	N/A
4	MONTEREY REGIONAL WATER	LU		0.00000	0.21390	N/A
5	WASTE MANAGEMENT RENEWABLE	LU		0.00000	4.93400	N/A
6	BIOMASS-WHEELABRATOR SHASTA	LU		49.68000	34.28670	N/A
7	HYDRO-CHARCOAL RAVINE	LU		0.00000	0.00050	N/A
8	EIF HAYPRESS LLC LWR	LU		0.00000	1.54350	N/A
9	EIF HAYPRESS LLC MDL	LU		0.00000	2.07830	N/A
10	EL DORADO MONTGOMERY CREEK	LU		0.00000	1.49590	N/A
11	FIVE BEARS HYDROELECTRIC	LU		0.00000	0.21400	N/A
12	GANSNER HYDRO	LU		0.00000	0.04580	N/A
13	HAT CREEK HEREFORD RANCH	LU		0.00000	0.01480	N/A
14	HYDRO PARTNERS CLOVER CREEK	LU		0.00000	0.83990	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	HYDRO SIERRA DEADWOOD CREEK	LU		0.00000	0.77700	N/A
2	HYPOWER INC.	LU		0.00000	5.16950	N/A
3	INDIAN VALLEY HYDRO	LU		0.00000	1.19990	N/A
4	JAMES B. PETER	LU		0.00000	0.00000	N/A
5	JAMES CRANE HYDRO	LU		0.00000	0.00050	N/A
6	KINGS RIVER HYDRO	LU		0.00000	0.34220	N/A
7	LOFTON RANCH	LU		0.00000	0.12570	N/A
8	MALACHA HYDRO L.P.	LU		0.00000	25.40150	N/A
9	NELSON CREEK POWER	LU		0.00000	0.28000	N/A
10	OLCESE WATER DISTRICT	LU		0.00000	4.37530	N/A
11	OLSEN POWER PARTNERS	LU		0.00000	1.75250	N/A
12	ORANGE COVE IRRIGATION DISTRICT	LU		0.00000	0.46400	N/A
13	SANTA CLARA VALLEY WATER DIST.	LU		0.00000	0.35320	N/A
14	SCHAADS HYDRO	LU		0.00000	0.11320	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	SNOW MOUNTAIN BURNEY CREEK	LU		0.00000	1.24890	N/A
2	SNOW MOUNTAIN COVE	LU		0.00000	2.51720	N/A
3	SNOW MT. PONDEROSA BAILEY CREEK	LU		0.00000	0.54500	N/A
4	SUTTER'S MILL SHAMROCK UTILITIES	LU		0.00000	0.00000	N/A
5	SWISS AMERICA	LU		0.00000	0.03110	N/A
6	TOM BENNINGHOVEN	LU		0.00000	0.00740	N/A
7	SOLAR-VILLA SORRISO SOLAR	LU		0.00000	0.00080	N/A
8	WIND-DONALD R. CHENOWETH	LU		0.00000	0.00070	N/A
9	EDF RENEWABLE WINDFARM V, INC (70	LU		0.00000	0.00000	N/A
10	EDF RENEWABLE INC 70 MW C	LU		0.00000	1.67040	N/A
11	EDF RENEWABLE INC 10 MW	LU		0.00000	0.00000	N/A
12	INTERNATIONAL TURBINE RESEARCH	LU		0.00000	6.66540	N/A
13	THERMAL:			0.00000	0.00000	
14	COGEN-1080 CHESTNUT CORP.	LU		0.00000	0.00170	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	AIRPORT CLUB	LU		0.00000	0.00210	N/A
2	ARDEN WOOD BENEVOLENT ASSOC.	LU		0.00000	0.00010	N/A
3	BERKELEY COGENERATION	LU		22.47000	2.40700	N/A
4	CALPINE KING CITY COGEN	LU		111.00000	121.05810	N/A
5	CHEVRON RICHMOND REFINERY	LU		0.00000	2.78330	N/A
6	COUNTY OF SANTA CRUZ (WATER ST.	LU		0.00000	0.00000	N/A
7	CROCKETT COGEN	LU		240.00000	239.77570	N/A
8	ECO SERVICES OPERATIONS LLC	LU		0.00000	0.36770	N/A
9	FRESNO COGENERATION PARTNERS, LP	LU		33.00000	21.42570	N/A
10	FRITO-LAY COGEN	LU		0.00000	0.52310	N/A
11	GREATER VALLEJO RECREATION DIST.	LU		0.00000	0.00380	N/A
12	GREENLEAF UNIT 1	LU		49.20000	48.04160	N/A
13	GREENLEAF UNIT 2	LU		49.20000	47.43360	N/A
14	HAYWARD AREA RECREATION AND PARK	LU		0.00000	0.04570	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	NIHONMACHI TERRACE	LU		0.00000	0.00130	N/A
2	ORINDA SENIOR VILLAGE	LU		0.00000	0.00140	N/A
3	PE KES KINGSBURG LLC	LU		34.50000	13.49420	N/A
4	PHILLIPS 66	LU		0.00000	8.16550	N/A
5	SATELLITE SENIOR HOMES	LU		0.00000	0.00470	N/A
6	SRI INTERNATIONAL	LU		0.00000	1.79630	N/A
7	YUBA CITY COGEN	LU		46.00000	42.79940	N/A
8	EOR-AERA ENERGY LLC COALINGA	LU		0.00000	1.81400	N/A
9	AERA ENERGY SOUTH BELRIDGE	LU		0.00000	1.33030	N/A
10	BERRY PETROLEUM CO - TANNEHILL	LU		0.00000	12.11800	N/A
11	CHEVRON USA TAFT/CADET	LU		0.00000	2.06630	N/A
12	CHEVRON USA CYMRIC	LU		0.00000	5.28770	N/A
13	CHEVRON USA COALINGA	LU		0.00000	3.41930	N/A
14	CHEVRON USA INC EASTRIDGE	LU		0.00000	11.35430	N/A
	Total					

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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1	CHEVRON USA INC SE KERN RIVER	LU		0.00000	7.94880	N/A
2	CHEVRON MCKITTRICK FHP	LU		0.00000	3.49840	N/A
3	COALINGA COGENERATION COMPANY	LU		37.70000	0.00000	N/A
4	FREEPORT MCMORAN DOME	LU		0.00000	1.83950	N/A
5	SENTINEL PEAK RESOURCES	LU		0.00000	1.83950	N/A
6	WESTERN POWER & STEAM INC	LU		17.75000	18.28810	N/A
7						
8	BILATERALS			0.00000	0.00000	
9	2041 ALVARES PRISTINE SUN			0.00000	0.00000	
10	2056 JARDINE PRISTINE SUN			0.00000	0.00000	
11	2059 SCHERZ			0.00000	0.00000	
12	2065 ROGERS PRISTINE SUN			0.00000	0.00000	
13	2081 TERZIAN			0.00000	0.00000	
14	2094 BUZZELLE PRISTINE SUN			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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1	2096 COTTON PRISTINE SUN			0.00000	0.00000	
2	2097 HELTON PRISTINE SUN			0.00000	0.00000	
3	2102 CHRISTENSEN PRISTINE SUN			0.00000	0.00000	
4	2103 HILL PRISTINE SUN			0.00000	0.00000	
5	2105 HART (Oroville Solar)			0.00000	0.00000	
6	2113 FITZJARRELL PRISTINE SUN			0.00000	0.00000	
7	2125 JARVIS PRISTINE SUN			0.00000	0.00000	
8	2127 HARRIS PRISTINE SUN			0.00000	0.00000	
9	2154 FOOTE (Oroville Solar)			0.00000	0.00000	
10	2158 STROING PRISTINE SUN			0.00000	0.00000	
11	2179 SMOTHERMAN			0.00000	0.00000	
12	2184 GRUBER (ENERPARC)			0.00000	0.00000	
13	2192 RAMIREZ (Oroville Solar)			0.00000	0.00000	
14	2018 REC Sales Oct-Dec Accrual			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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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	3 PHASES 2017 REC SALE			0.00000	0.00000	
2	3 PHASES RENEWABLES INC			0.00000	0.00000	
3	ABEC #2 LLC			0.00000	0.00000	
4	ABEC #3 LLC			0.00000	0.00000	
5	ABEC #4 LLC			0.00000	0.00000	
6	ABEC BIDART OLD RIVER			0.00000	0.00000	
7	ABEC BIDART-STOCKDALE LLC			0.00000	0.00000	
8	AGUA CALIENTE SOLAR			0.00000	0.00000	
9	ALAMO SOLAR			0.00000	0.00000	
10	ALGONQUIN SANGER POWER LLC			0.00000	0.00000	
11	ALGONQUIN SKIC 20 SOLAR, LLC			0.00000	0.00000	
12	ALPAUGH 50, LLC			0.00000	0.00000	
13	ALPAUGH NORTH, LLC			0.00000	0.00000	
14	Anahau Energy, LLC EEI Master			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	ANGELS POWERHOUSE			0.00000	0.00000	
2	APEX 646-460			0.00000	0.00000	
3	ARBUCKLE MOUNTAIN HYDRO			0.00000	0.00000	
4	ARLINGTON WIND POWER PROJECT			0.00000	0.00000	
5	ASPIRATION SOLAR G			0.00000	0.00000	
6	ATWELL ISLAND			0.00000	0.00000	
7	AV SOLAR RANCH ONE			0.00000	0.00000	
8	AVENAL SOLAR PROJECT A			0.00000	0.00000	
9	AVENAL SOLAR PROJECT B			0.00000	0.00000	
10	BADGER CREEK LIMITED			0.00000	0.00000	
11	BAKER CREEK HYDROELECTRIC			0.00000	0.00000	
12	BAKERSFIELD 111 LLC			0.00000	0.00000	
13	BAKERSFIELD INDUSTRIAL 1			0.00000	0.00000	
14	BAKERSFIELD PV 1			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	BAYSHORE SOLAR A			0.00000	0.00000	
2	BAYSHORE SOLAR B			0.00000	0.00000	
3	BAYSHORE SOLAR C			0.00000	0.00000	
4	BEAR CREEK SOLAR LLC			0.00000	0.00000	
5	BEAR MOUNTAIN LIMITED			0.00000	0.00000	
6	BGC BROKERAGE			0.00000	0.00000	
7	BIG CREEK WATER WORKS			0.00000	0.00000	
8	BLACKSPRING RIDGE 1A			0.00000	0.00000	
9	BLACKSPRING RIDGE 1B			0.00000	0.00000	
10	BLAKE'S LANDING FARMS INC			0.00000	0.00000	
11	BONNEVILLE POWER ADMINSTRATION			0.00000	0.00000	
12	BP Energy Company			0.00000	0.00000	
13	BPA TSA			0.00000	0.00000	
14	BROWNS VALLEY IRRIGATION DIST			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.
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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	BUCKEYE HYDROELECTRIC PROJECT			0.00000	0.00000	
2	BURNEY FOREST PRODUCTS			0.00000	0.00000	
3	CALAVERAS PUBLIC UTILI. DIST. 1			0.00000	0.00000	
4	CALAVERAS PUBLIC UTILI. DIST. 2			0.00000	0.00000	
5	CALAVERAS PUBLIC UTILI. DIST. 3			0.00000	0.00000	
6	CALPINE ENERGY - AGNEWS, INC			0.00000	0.00000	
7	CALPINE ENERGY EEI			0.00000	0.00000	
8	CALPINE GEYSERS (200/425 MW)			0.00000	0.00000	
9	CALPINE GEYSERS RETAINED ASSET			0.00000	0.00000	
10	CALPINE LOS ESTEROS UPGRADE			0.00000	0.00000	
11	CALPINE PEAKERS			0.00000	0.00000	
12	CALPINE RUSSELL CITY			0.00000	0.00000	
13	CALRENEW CLEANTECH			0.00000	0.00000	
14	CAMS DOUBLE C LIMITED			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.
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1	CAMS HIGH SIERRA LIMITED			0.00000	0.00000	
2	CAMS KERN FRONT LIMITED			0.00000	0.00000	
3	CASTELANELLI BROS BIOGAS			0.00000	0.00000	
4	CASTOR SOLAR PROJECT			0.00000	0.00000	
5	CE of Montana			0.00000	0.00000	
6	CED CORCORAN SOLAR 3 LLC			0.00000	0.00000	
7	CED WHITE RIVER SOLAR, LLC			0.00000	0.00000	
8	CEDAR FLAT (Shamrock Utilities)			0.00000	0.00000	
9	CHALK CLIFF LIMITED			0.00000	0.00000	
10	CID SOLAR LLC RAM 2			0.00000	0.00000	
11	CITY OF SAN JOSE					
12	CITY OF SJ"			0.00000	0.00000	
13	CITY OF SANTA CLARA SVP MUNI			0.00000	0.00000	
14	CITY OF VERNON			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.
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1	CLEAN PWR ALLIANCE			0.00000	0.00000	
2	CLEANPOWERSF			0.00000	0.00000	
3	CLOVER FLAT LFG			0.00000	0.00000	
4	CLOVER LEAF (Shamrock Utilities)			0.00000	0.00000	
5	CLOVERDALE SOLAR 1, LLC			0.00000	0.00000	
6	COLUMBIA SOLAR ENERGY LLC			0.00000	0.00000	
7	COPPER MOUNTAIN 10			0.00000	0.00000	
8	COPPER MOUNTAIN SOLAR 2 (SEMPRA)			0.00000	0.00000	
9	COPPER MOUNTAIN SOLAR 48			0.00000	0.00000	
10	CORAM BRODIE WIND			0.00000	0.00000	
11	CORCORAN SOLAR			0.00000	0.00000	
12	DELANO PV 1 LLC			0.00000	0.00000	
13	DESERT CENTER SOLAR FARM			0.00000	0.00000	
14	DIGGER CREEK HYDRO			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	DIRECT ENERGY BUSINESS MARKETING			0.00000	0.00000	
2	DTE STOCKTON			0.00000	0.00000	
3	DTE SUNSHINE GAS LANDFILL			0.00000	0.00000	
4	EAST BAY COMMUNITY ENERGY			0.00000	0.00000	
5	EAST BAY COMMUNITY ENERGY			0.00000	0.00000	
6	ECOS ENERGY LLC KETTLEMAN SOLAR			0.00000	0.00000	
7	EDF TRADING - BU			0.00000	0.00000	
8	EDF TRADING 2017 REC SALE			0.00000	0.00000	
9	EDF Trading EEI			0.00000	0.00000	
10	EIF PANOCHE (FIREBAUGH)			0.00000	0.00000	
11	EL DORADO IRRIGATION DISTRICT			0.00000	0.00000	
12	ENERPARC CA1 LLC			0.00000	0.00000	
13	EQUUS ENERGY BROKER			0.00000	0.00000	
14	ETIWANDA POWER PLANT			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	EURUS (AVENAL PARK, LLC)			0.00000	0.00000	
2	EURUS (SAND DRAG, LLC)			0.00000	0.00000	
3	EURUS (SUN CITY PROJECT, LLC)			0.00000	0.00000	
4	Exelon			0.00000	0.00000	
5	EXELON GENERATION COMPANY			0.00000	0.00000	
6	EXELON GENERATION WSPP			0.00000	0.00000	
7	FALL RIVER MILLS A ACHOMAWI			0.00000	0.00000	
8	FALL RIVER MILLS B AHJUMAWI			0.00000	0.00000	
9	FPL Energy Power Marketing Inc.			0.00000	0.00000	
10	FRESH AIR ENERGY IV SONORA 1			0.00000	0.00000	
11	FRESNO SOLAR SOUTH			0.00000	0.00000	
12	FRESNO SOLAR WEST			0.00000	0.00000	
13	GAS TRANSPORT ASSOC WITH PANOCHE			0.00000	0.00000	
14	GENESIS SOLAR ENERGY PROJECT			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	GEYSERS 50/250/425 MW			0.00000	0.00000	
2	GLOBAL AMPERSAND, CHOWCHILLA			0.00000	0.00000	
3	GLOBAL AMPERSAND, EL NIDO			0.00000	0.00000	
4	GOOSE VALLEY FARMING, LLC			0.00000	0.00000	
5	GREEN LIGHT ENERGY SIRUIS SOLAR			0.00000	0.00000	
6	GREEN LIGHT MADERA 1			0.00000	0.00000	
7	GWF HANFORD			0.00000	0.00000	
8	GWF HENRIETTA			0.00000	0.00000	
9	GWF TRACY REPOWERING PPA			0.00000	0.00000	
10	HALKIRK I WIND PROJECT			0.00000	0.00000	
11	HATCHET RIDGE WIND LLC			0.00000	0.00000	
12	HENRIETTA SOLAR			0.00000	0.00000	
13	HIGH PLAINS RANCH II			0.00000	0.00000	
14	HIGH PLAINS RANCH III			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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

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

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

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

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

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	HOLLISTER SOLAR ECOS ENERGY			0.00000	0.00000	
2	IBERDROLA KLONDIKE (AKA PPM			0.00000	0.00000	
3	IBERDROLA RENEWABLES (AKA PPM			0.00000	0.00000	
4	ICE Broker Agreement			0.00000	0.00000	
5	IVANPAH UNIT 1			0.00000	0.00000	
6	IVANPAH UNIT 3			0.00000	0.00000	
7	JACKSON VALLEY IRRIGATION DIST			0.00000	0.00000	
8	KANSAS			0.00000	0.00000	
9	KEKAWAKA CREEK HYDRO RAM 4			0.00000	0.00000	
10	KENT SOUTH - PV 2			0.00000	0.00000	
11	KERN RIVER COGEN (KRCC)			0.00000	0.00000	
12	KINGSBURG 1 TULARE PV II LLC			0.00000	0.00000	
13	KINGSBURG 2 TULARE PV II LLC			0.00000	0.00000	
14	KINGSBURG 3 TULARE PV II LLC			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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	KLONDIKE WIND IIIA POWER			0.00000	0.00000	
2	LA JOYA DEL SOL 1			0.00000	0.00000	
3	LASSEN STATION			0.00000	0.00000	
4	LEMOORE PV 1, LLC			0.00000	0.00000	
5	LIVE OAK LIMITED			0.00000	0.00000	
6	LOST CREEK 1			0.00000	0.00000	
7	LOST CREEK 2			0.00000	0.00000	
8	Macquarie Futures			0.00000	0.00000	
9	MACQUARIE FUTURES USA - EGS-FCM			0.00000	0.00000	
10	MADERA CHOWCHILLA - SITE 1923			0.00000	0.00000	
11	MADERA CHOWCHILLA SITE 1174			0.00000	0.00000	
12	MADERA CHOWCHILLA SITE 1302			0.00000	0.00000	
13	MADERA CHOWCHILLA SITE 980			0.00000	0.00000	
14	MAMMOTH G1 (ORMAT) - RAM 2			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	MAMMOTH G3 (M3 ORMAT) - RAM 1			0.00000	0.00000	
2	MANTECA LAND 1			0.00000	0.00000	
3	MARIN CLEAN ENERGY - BU			0.00000	0.00000	
4	MARIN CLEAN ENERGY EEI			0.00000	0.00000	
5	MARIPOSA ENERGY, LLC			0.00000	0.00000	
6	MARSH LANDING			0.00000	0.00000	
7	MATTHEWS DAM HYDRO			0.00000	0.00000	
8	MBCPA - BU			0.00000	0.00000	
9	MCFADDEN HYDRO FACILITY			0.00000	0.00000	
10	MCKITTRICK LIMITED			0.00000	0.00000	
11	MERCED 1			0.00000	0.00000	
12	MERCED IRRIGATION DISTRICT			0.00000	0.00000	
13	MERCED SOLAR ECOS ENERGY			0.00000	0.00000	
14	MESQUITE SOLAR			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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	MIDWAY SUNSET COGENERATION			0.00000	0.00000	
2	MILL SULPHUR CREEK PROJECT			0.00000	0.00000	
3	MISSION SOLAR ECOS ENERGY			0.00000	0.00000	
4	MOJAVE SOLAR			0.00000	0.00000	
5	MONTEREY BAY COMMUNITY POWER			0.00000	0.00000	
6	MORELOS SOLAR LLC - RAM 3			0.00000	0.00000	
7	Morgan Stanley			0.00000	0.00000	
8	MORGAN STANLEY CAPITAL GROUP EEI			0.00000	0.00000	
9	MT. POSO (RED HAWK)			0.00000	0.00000	
10	NCPA			0.00000	0.00000	
11	NEXTERA DIABLO WINDS			0.00000	0.00000	
12	NEXTERA MONTEZUMA WIND			0.00000	0.00000	
13	NEXTERA MONTEZUMA WIND II			0.00000	0.00000	
14	NICKEL 1 NLH1 SOLAR			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.
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1	NID CHICAGO PARK			0.00000	0.00000	
2	NID NORTH COMBIE FIT			0.00000	0.00000	
3	NID SCOTTS FLAT			0.00000	0.00000	
4	NID SOUTH COMBIE FIT			0.00000	0.00000	
5	NID-DUTCH FLATS, ROLLINS, BOWMAN			0.00000	0.00000	
6	NORTH SKY RIVER ENERGY CENTER			0.00000	0.00000	
7	NORTH STAR SOLAR			0.00000	0.00000	
8	NRG ALPINE SOLAR			0.00000	0.00000	
9	NRG POWER MARKETING LLC			0.00000	0.00000	
10	NRG SOLAR KANSAS SOUTH			0.00000	0.00000	
11	OAKLEY EXECUTIVE LLC			0.00000	0.00000	
12	OLD RIVER ONE LLC - RAM 3			0.00000	0.00000	
13	ORION SOLAR I LLC			0.00000	0.00000	
14	OROVILLE COGEN TOLLING			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	ORTIGALITA POWER COMPANY LLC			0.00000	0.00000	
2	PACIFICORP TSA			0.00000	0.00000	
3	PCWA LINCOLN HYDRO			0.00000	0.00000	
4	PEACOCK SOLAR PROJ - GREEN LIGHT			0.00000	0.00000	
5	PENINSULA 2017 REC SALE			0.00000	0.00000	
6	PENINSULA CLEAN ENERGY			0.00000	0.00000	
7	PENINSULA CLEAN ENERGY EEI			0.00000	0.00000	
8	PILOT POWER GROUP INC			0.00000	0.00000	
9	PIONEER COMM ENERGY			0.00000	0.00000	
10	PLACER COUNTY WATER AGENCY			0.00000	0.00000	
11	PORTAL RIDGE SOLAR C PROJECT			0.00000	0.00000	
12	POTRERO HILL ENERGY PRODCERS LLC			0.00000	0.00000	
13	POWEREX SHAPING FIRMING			0.00000	0.00000	
14	PUTAH CREEK SOLAR FARMS			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.

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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	REDWOOD 4 SOLAR FARM			0.00000	0.00000	
2	RIPON COGENERATION LLC			0.00000	0.00000	
3	RISING TREE WIND FARM II LLC - RAM 4			0.00000	0.00000	
4	ROCK CREEK HYDRO			0.00000	0.00000	
5	SALMON CREEK HYDROELECTRIC			0.00000	0.00000	
6	SAN JOSE CLEAN ENERGY			0.00000	0.00000	
7	SAN JOSE WATER COX AVE HYDRO			0.00000	0.00000	
8	SAN LUIS BYPASS			0.00000	0.00000	
9	SANTA MARIA II LFG POWER PLANT			0.00000	0.00000	
10	SEMPRA GENERATION EEI			0.00000	0.00000	
11	SEMPRA MESQUITE SOLAR			0.00000	0.00000	
12	SHAFTER SOLAR LLC RAM 3			0.00000	0.00000	
13	SHELL ENERGY NORTH AMERICA			0.00000	0.00000	
14	SHILOH I WIND			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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	SHILOH I WIND PROJECT LLC			0.00000	0.00000	
2	SHILOH II WIND (AKA ENXCO)			0.00000	0.00000	
3	SHILOH II WIND PROJECT			0.00000	0.00000	
4	SHILOH III (ENXCO)			0.00000	0.00000	
5	SHILOH III WIND PROJECT			0.00000	0.00000	
6	SHILOH IV			0.00000	0.00000	
7	SIERRA GREEN ENERGY LLC			0.00000	0.00000	
8	SIERRA PACIFIC INDUSTRIES			0.00000	0.00000	
9	SIERRA PACIFIC POWER TSA			0.00000	0.00000	
10	SILICON VALLEY CLEAN ENERGY			0.00000	0.00000	
11	SILICON VALLEY CLEAN ENERGY EEI			0.00000	0.00000	
12	SILVER SPRINGS			0.00000	0.00000	
13	SMUD WSPP			0.00000	0.00000	
14	SO CAL EDISON EEI AGREEMENT			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:

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SONOMA CLEAN POWER AUTHORITY			0.00000	0.00000	
2	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
3	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
4	SOUTH SUTTER WATER DISTRICT			0.00000	0.00000	
5	SR Solis Oro Loma Teresina Solar Proje			0.00000	0.00000	
6	SR Solis Oro Loma Teresina Solar Proje			0.00000	0.00000	
7	STARWOOD POWER MIDWAY, LLC			0.00000	0.00000	
8	SUN HARVEST SOLAR, LLC (NDP1)			0.00000	0.00000	
9	SUNRAY 2			0.00000	0.00000	
10	SUNRISE POWER COMPANY LLC			0.00000	0.00000	
11	SUTTERS MILL HYDROELECTRIC PLANT			0.00000	0.00000	
12	TESORO REFINING & MARKETING LLC			0.00000	0.00000	
13	THE ENERGY AUTHORITY - BU			0.00000	0.00000	
14	THE ENERGY AUTHORITY EEI			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.
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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	THREE FORKS			0.00000	0.00000	
2	TOPAZ SOLAR FARM			0.00000	0.00000	
3	TORO SLO LANDFILL			0.00000	0.00000	
4	TRANQUILLITY 8 AMARILLO			0.00000	0.00000	
5	TRANSALTA ENREGY MARKETING US			0.00000	0.00000	
6	TUNNEL HILL HYDRO			0.00000	0.00000	
7	TWIN VALLEY HYDRO			0.00000	0.00000	
8	VANTAGE WIND (POWEREX S&F)			0.00000	0.00000	
9	VANTAGE WIND ENERGY LLC			0.00000	0.00000	
10	VASCO WINDS (NEXTERA)			0.00000	0.00000	
11	VINTNER SOLAR PROJECT			0.00000	0.00000	
12	WADHAM ENERGY LP			0.00000	0.00000	
13	WATER WHEEL RANCH			0.00000	0.00000	
14	WECC WREGIS Fees			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	WEST ANTELOPE - RAM 1			0.00000	0.00000	
2	WESTERN ANTELOPE BLUE SKY RANCH			0.00000	0.00000	
3	WESTLANDS SOLAR FARMS LLC			0.00000	0.00000	
4	WESTSIDE SOLAR			0.00000	0.00000	
5	WHEELABRATOR SHASTA BIOMASS			0.00000	0.00000	
6	WHEELABRATOR SHASTA BIORAM			0.00000	0.00000	
7	WHITE RIVER SOLAR 2			0.00000	0.00000	
8	WHITE RIVER SOLAR CED			0.00000	0.00000	
9	WIND RESOURCE 1 (CALWIND) - RAM 1			0.00000	0.00000	
10	WIND RESOURCE 2 (CALWIND) - RAM 2			0.00000	0.00000	
11	WOLFSEN BYPASS FIT			0.00000	0.00000	
12	WOODLAND BIOMASS			0.00000	0.00000	
13	WOODMERE SOLAR RAM 4			0.00000	0.00000	
14	YCWA MINI HYDRO			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.
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1	YOLO COUNTY GRASSLAND 3			0.00000	0.00000	
2	YOLO COUNTY GRASSLAND 4			0.00000	0.00000	
3	ZERO WASTE ENERGY DEVELOPMENT			0.00000	0.00000	
4						
5						
6	Pipeline charges			0.00000	0.00000	
7	RUBY PIPELINE			0.00000	0.00000	
8	WILLIAMS FIELD SERVICES -			0.00000	0.00000	
9	SOUTHERN CA GAS - BU			0.00000	0.00000	
10						
11	Other charges			0.00000	0.00000	
12	Irrigation districts			0.00000	0.00000	
13	Liberty Utilities			0.00000	0.00000	
14	ISO charges for storage cost			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.
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1	ISO charges (net of storage cost but			0.00000	0.00000	
2	Gas purchases, storage cost & forex			0.00000	0.00000	
3	CARB fees			0.00000	0.00000	
4	Consultancy fees			0.00000	0.00000	
5	Gas Hedges & brokers fees			0.00000	0.00000	
6	RECS from customers			0.00000	0.00000	
7						
8	Rounding issues in columns I					
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
27			82	1,337		1,419	3
487			2,872	16,633		19,505	4
2,580			5,758	94,512		100,270	5
1,192			-21,870	27,851		5,981	6
3			14	114		128	7
6,622			124,678	237,373		362,051	8
9,363			167,766	334,978		502,744	9
5,233			64,650	706,165		770,815	10
282			1,868	10,020		11,888	11
108			553	3,834		4,387	12
13,108			356,938	555,063		912,001	13
1,317			5,373	41,539		46,912	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,906			23,431	62,643		86,074	1
28,312			295,160	914,232		1,209,392	2
2,385			20,215	81,525		101,740	3
26			103	804		907	4
4			10	150		160	5
1,406			38,356	55,517		93,873	6
964			6,059	33,463		39,522	7
47,753			1,538,760	1,867,768		3,406,528	8
974			12,540	35,810		48,350	9
23,754			198,636	903,579		1,102,215	10
6,098			60,387	204,655		265,042	11
3,853			82,535	143,847		226,382	12
2,089				77,630		77,630	13
365			1,954	12,605		14,559	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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.

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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)	
3,386			36,361	124,070		160,431	1
9,196			143,057	698,793		841,850	2
1,779			28,766	43,574		72,340	3
-61			-139	-2,273		-2,412	4
212			1,823	7,631		9,454	5
49			225	1,794		2,019	6
7			25	246		271	7
6			21	223		244	8
-1,144			-1,361	-41,924		-43,285	9
3,541			92,854	133,606		226,460	10
782			1,523	26,570		28,093	11
10,720			257,011	392,665		649,676	12
							13
15			58	564		622	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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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)	
17			50	626		676	1
1			4	36		40	2
8,799			60,237	147,916		208,153	3
393,881			24,936,469	14,695,346		39,631,815	4
1,156			2,639	55,392		58,031	5
				-7		-7	6
1,393,652			52,220,644	56,180,444		108,401,088	7
357			1,029	13,330		14,359	8
1,683			7,305,734	199,384		7,505,118	9
632			3,859	24,677		28,536	10
36			109	1,269		1,378	11
73,004			9,042,139	3,506,775		12,548,914	12
224,224			10,015,038	8,021,211		18,036,249	13
407			1,240	15,020		16,260	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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13			40	487		527	1
14			40	546		586	2
4,443			8,851,300	311,365		9,162,665	3
22,202			127,965	870,675		998,640	4
2				57		57	5
7,129			16,348	278,781		295,129	6
10,655			10,444,146	484,681		10,928,827	7
5,484			27,182	230,290		257,472	8
4,852			22,710	169,664		192,374	9
90,144			675,895	3,464,323		4,140,218	10
4,239			36,949	166,985		203,934	11
21,550			135,086	825,170		960,256	12
11,252			112,038	420,854		532,892	13
14,725			78,562	584,295		662,857	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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4,078			34,728	155,547		190,275	1
19,701				1,260,401		1,260,401	2
			150,000			150,000	3
7,808			40,555	279,581		320,136	4
82			-2,957	42,290		39,333	5
134,424			1,548,892	5,100,979		6,649,871	6
							7
							8
552				78,789		78,789	9
2,240				313,368		313,368	10
1,014				143,118		143,118	11
533				73,308		73,308	12
1,459				208,583		208,583	13
590				79,616		79,616	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,889				283,192		283,192	1
241				29,133		29,133	2
2,183				311,460		311,460	3
590				86,747		86,747	4
1,105				81,335		81,335	5
601				81,154		81,154	6
542				79,124		79,124	7
2,633				389,800		389,800	8
493				64,740		64,740	9
1,166				166,623		166,623	10
560				82,424		82,424	11
3,422				344,700		344,700	12
1,028				136,445		136,445	13
-1,001,962				-16,795,368		-16,795,368	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-13,721				-226,397		-226,397	1
			-970,300			-970,300	2
2,629				524,367		524,367	3
14,907				2,733,671		2,733,671	4
2,574				523,641		523,641	5
11,883				1,727,324		1,727,324	6
849				151,259	-404	150,855	7
727,004				127,047,414		127,047,414	8
52,717				4,549,112		4,549,112	9
			8,168,240			8,168,240	10
48,129				4,275,544		4,275,544	11
120,849				20,121,508		20,121,508	12
48,144				7,658,962		7,658,962	13
			-5,291,500			-5,291,500	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,831				641,616		641,616	1
1,804				234,362		234,362	2
30				2,392		2,392	3
223,688				22,757,238		22,757,238	4
22,418				1,484,040		1,484,040	5
39,526				6,563,130		6,563,130	6
603,741				92,957,348	-3,000,000	89,957,348	7
17,391				970,391		970,391	8
16,977				951,949		951,949	9
8,098			3,903,454	155,570		4,059,024	10
3,250				331,687		331,687	11
2,963				388,561		388,561	12
2,201				158,494		158,494	13
10,763				440,110		440,110	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
59,488				3,317,811		3,317,811	1
60,813				3,364,350		3,364,350	2
58,844				3,279,556		3,279,556	3
3,316				495,458		495,458	4
38,833			3,903,454	573,310		4,476,764	5
					16,170	16,170	6
6,338				565,095		565,095	7
				15,019,220		15,019,220	8
				16,224,527		16,224,527	9
172				13,725		13,725	10
				554,313		554,313	11
107,913			-253,600	9,316,573		9,062,973	12
					5,161	5,161	13
3,251				258,571		258,571	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	
1,486				141,061		141,061	1
					-9,300	-9,300	2
483				47,119		47,119	3
291				28,176		28,176	4
126				12,235		12,235	5
16,289			5,895,251	308,486		6,203,737	6
			-1,023,500			-1,023,500	7
180,250				16,462,518		16,462,518	8
					18,344	18,344	9
365,125			67,348,231	7,760,890		75,109,121	10
89,971			31,239,530	3,670,844		34,910,374	11
1,342,740			144,530,861	20,638,030		165,168,891	12
9,899				2,229,862		2,229,862	13
26,511			5,096,356	549,529	-17,252	5,628,633	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
28,158			5,073,452	598,394	-19,528	5,652,318	1
18,988			5,094,374	692,762	-14,072	5,773,064	2
906				86,857		86,857	3
2,619				336,201		336,201	4
			-348,250			-348,250	5
52,178				2,554,984		2,554,984	6
1,332				177,441		177,441	7
993				100,890		100,890	8
16,765			3,885,559	305,254		4,190,813	9
52,849				5,657,262		5,657,262	10
							11
			-240,540			-240,540	12
			-699,750			-699,750	13
			-126,500			-126,500	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
			-338,919			-338,919	1
			-5,275,400			-5,275,400	2
5,199				519,391	-2,787	516,604	3
716				75,797		75,797	4
2,601				383,147		383,147	5
38,127				3,780,655	-200,000	3,580,655	6
20,587				3,349,717		3,349,717	7
373,073				48,359,434		48,359,434	8
99,882				16,243,373		16,243,373	9
275,443				31,679,368		31,679,368	10
50,114				7,500,814		7,500,814	11
2,186				158,367		158,367	12
737,230				116,803,579		116,803,579	13
3,033				307,728		307,728	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
			-2,219,750			-2,219,750	1
372,295				48,523,322		48,523,322	2
149,138				17,988,201		17,988,201	3
-378,778			-20,935,413	-1,738,591		-22,674,004	4
-156,222				-717,059		-717,059	5
2,223				321,462		321,462	6
			364,500			364,500	7
				283,357		283,357	8
			6,142,972			6,142,972	9
636,160			55,634,546	5,567,591		61,202,137	10
59,377				5,878,544		5,878,544	11
3,594				530,100		530,100	12
					5,040	5,040	13
50,133				2,199,661		2,199,661	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (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)	
10,443				2,637,099		2,637,099	1
35,044				8,767,139		8,767,139	2
36,799				9,206,217		9,206,217	3
60,000				2,347,484		2,347,484	4
-250,000				-4,000,000		-4,000,000	5
125,876			-7,857,450	6,122,882		-1,734,568	6
3,458				509,515		509,515	7
3,437				507,643		507,643	8
			-250,250			-250,250	9
3,596				504,882		504,882	10
3,031				394,508		394,508	11
3,221				416,989		416,989	12
				1,484,416		1,484,416	13
621,742				133,270,780	-2,360,000	130,910,780	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,003,824			10,862,500	154,438,678		165,301,178	1
69,781				7,830,172		7,830,172	2
67,970				7,527,476		7,527,476	3
281				25,477		25,477	4
1,448				185,492		185,492	5
2,863				161,114		161,114	6
15,604			8,369,979	216,350		8,586,329	7
32,573			8,308,350	565,484		8,873,834	8
911,735			66,895,676	10,746,212		77,641,888	9
				16,851,744	842,587	17,694,331	10
242,474				25,781,312		25,781,312	11
252,661				26,281,045		26,281,045	12
553,146				72,823,849	-7,650,000	65,173,849	13
111,253				15,587,362	-1,350,000	14,237,362	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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.

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,076				545,335		545,335	1
202,019				11,818,140		11,818,140	2
19,953				5,732,398		5,732,398	3
					107,450	107,450	4
239,049				39,116,577	-1,000,000	38,116,577	5
277,399				45,559,054	-1,100,000	44,459,054	6
801				72,409		72,409	7
52,264				5,395,223		5,395,223	8
7,513				500,535		500,535	9
52,614				4,553,039		4,553,039	10
732,322			22,109,935	26,651,081		48,761,016	11
2,831				398,845		398,845	12
2,924				407,285		407,285	13
1,419				198,547		198,547	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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.

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
228,990				17,943,046		17,943,046	1
3,098				398,205		398,205	2
3,406				357,114		357,114	3
3,552				480,912		480,912	4
25,146			3,891,874	465,701		4,357,575	5
5,523				563,961		563,961	6
2,537				257,917		257,917	7
					862,471	862,471	8
					830,992	830,992	9
1,474				129,456		129,456	10
1,379				122,358		122,358	11
825				73,792		73,792	12
3,915				347,870		347,870	13
56,816				4,871,902		4,871,902	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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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)	
85,693				7,774,977		7,774,977	1
1,888				146,515		146,515	2
			-220,000			-220,000	3
			-9,966,458			-9,966,458	4
112,215			29,859,433	2,029,011		31,888,444	5
203,650			118,582,704	5,463,398		124,046,102	6
4,398				468,161		468,161	7
			-84,990			-84,990	8
-3,223				303,561		303,561	9
30,290			3,867,158	324,473		4,191,631	10
5,332				210,100		210,100	11
				-135,965		-135,965	12
2,678				345,193		345,193	13
30,332				3,962,762		3,962,762	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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.

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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)	
838,496			14,312,723	-4,858,988		9,453,735	1
1,142				118,605		118,605	2
2,708				348,718		348,718	3
602,251				120,925,541	-6,227,437	114,698,104	4
			-11,484,910			-11,484,910	5
38,517				3,500,901		3,500,901	6
20,000				879,072		879,072	7
103,029			183,750	3,039,010		3,222,760	8
242,938				32,289,860	-350,000	31,939,860	9
			-1,481,500			-1,481,500	10
61,538				3,435,835		3,435,835	11
95,498				9,645,261	-320,000	9,325,261	12
214,040				21,837,602		21,837,602	13
2,830				377,148		377,148	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
119,406				10,784,248		10,784,248	1
1,494				160,739		160,739	2
4,321				383,752		383,752	3
5,576				520,804		520,804	4
136,247				12,333,536		12,333,536	5
441,975				38,407,665		38,407,665	6
154,435				19,914,450		19,914,450	7
162,698				23,738,562		23,738,562	8
			-35,468			-35,468	9
48,988				4,657,853		4,657,853	10
2,219				317,895		317,895	11
50,330				4,251,478		4,251,478	12
29,115				3,698,712		3,698,712	13
206			1,110,435	-1,900		1,108,535	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				-3		-3	1
					7,891	7,891	2
1,329				144,031		144,031	3
1,817				243,159		243,159	4
							5
			-541,750			-541,750	6
			-4,390,484			-4,390,484	7
			-837,750			-837,750	8
			-1,898,700			-1,898,700	9
375,067				592,893		592,893	10
30,107				1,942,471		1,942,471	11
63,121				7,869,023		7,869,023	12
				1,553,805		1,553,805	13
4,706				559,128		559,128	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
50,557				3,059,308		3,059,308	1
3,463			2,014,950	44,227		2,059,177	2
56,129				3,451,960		3,451,960	3
1,538				131,064		131,064	4
1,765				195,997		195,997	5
			-157,040			-157,040	6
291				35,294		35,294	7
807				84,869		84,869	8
5,574				555,481		555,481	9
			-39,000			-39,000	10
392,125				61,771,043		61,771,043	11
50,794				4,831,287		4,831,287	12
-500			402,240	-6,978		395,262	13
178,304				9,869,468		9,869,468	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,183				352,559		352,559	1
39,527				3,434,919		3,434,919	2
345,755				30,478,099		30,478,099	3
9,190				1,054,521		1,054,521	4
268,922				30,867,189		30,867,189	5
293,263				26,407,778		26,407,778	6
134				16,140		16,140	7
335,550				32,140,793	-634,866	31,505,927	8
					24,030	24,030	9
-200,000				-3,390,000		-3,390,000	10
			-10,635,980			-10,635,980	11
1,890				198,672		198,672	12
			-4,318,830			-4,318,830	13
			-1,510,000			-1,510,000	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
			-1,945,305			-1,945,305	1
234,421			3,376,794	9,033,377		12,410,171	2
17,463			242,902	1,016,177		1,259,079	3
28				2,342		2,342	4
26,244				1,291,908		1,291,908	5
26,032				1,280,840		1,280,840	6
49,957			13,465,564	785,524		14,251,088	7
3,060				303,138		303,138	8
59,938				3,578,614		3,578,614	9
			14,767,200			14,767,200	10
723				75,003		75,003	11
90,266			779,462	4,937,060		5,716,522	12
			-89,920			-89,920	13
			-1,213,300			-1,213,300	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,210				519,304		519,304	1
1,646,016				217,496,672	731	217,497,403	2
10,244				1,143,956		1,143,956	3
60,257				3,659,933		3,659,933	4
538,274			-549,550	20,874,970		20,325,420	5
2,424				237,217		237,217	6
1,449				166,971		166,971	7
			-193,088	9,315,820		9,122,732	8
243,974				24,998,512	-1,524,000	23,474,512	9
233,730				25,248,586		25,248,586	10
3,679				538,161		538,161	11
57,290				4,881,747		4,881,747	12
1,817				195,412		195,412	13
				117,491		117,491	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	
39,130				3,413,748		3,413,748	1
53,901				3,693,052		3,693,052	2
43,794				5,747,956		5,747,956	3
53,328				3,351,144		3,351,144	4
					-3,300	-3,300	5
					-6,000	-6,000	6
49,361				4,874,910		4,874,910	7
49,923				7,689,785		7,689,785	8
14,005				1,041,388		1,041,388	9
47,599				3,557,582		3,557,582	10
2,892				289,593		289,593	11
190,679				19,358,392		19,358,392	12
35,627				2,574,253		2,574,253	13
1,161				126,572		126,572	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	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.
2,049				259,464		259,464	1
2,199				279,869		279,869	2
4,380				570,019	-1,643	568,376	3
							4
							5
							6
					12,686,997	12,686,997	7
					6,325	6,325	8
					10,762	10,762	9
							10
							11
-7,707					9,010,298	9,010,298	12
5,040					862,378	862,378	13
					-220,207	-220,207	14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,863,083					257,845,224	257,845,224	1
					99,908,760	99,908,760	2
					620,611	620,611	3
					338,215	338,215	4
					18,364,404	18,364,404	5
							6
							7
					1,906	1,906	8
							9
							10
							11
							12
							13
							14
31,325,610			701,694,986	2,418,783,649	376,365,951	3,496,844,586	

Schedule Page: 326.28 Line No.: 8 Column: a

The original entries in column l were in two decimal places, which the FERC software rounds automatically to whole numbers. The entry here is an adjustment to present the correct total.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1				
2	TRANSMISSION AGENCY OF			
3	NORTHERN CALIFORNIA (TANC)	Various	Various	LFP
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)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						1
						2
143	Midway	Various	233	366,570	359,638	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
			233	**366,570**	**359,638**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
	1,845,837		1,845,837	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	**1,845,837**	**0**	**1,845,837**	

Schedule Page: 328 Line No.: 3 Column: a

Other Charges represent booking estimate adjustments. In September 2003 the Utility changed billing methodology using energy as billing determinants rather than contract demand. The change was pursuant to the TO6 Settlement Agreement under FERC Docket No. ER03-666-000.

Transmission is provided under the Midway Transmission Service.

Recorded here are the Midway Transmission Service data for TANC members which include Modesto Irrigation District, Sacramento Municipal Utility District, City of Redding, and the Turlock Irrigation District.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1	NONE				
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 PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	CALIFORNIA-OREGON							
2	TRANSMISSION PROJECT	OS					351,510	351,510
3	PACIFICORP	OS			149,118		89,102	238,220
4	SACRAMENTO MUNICIPAL							
5	UTILITY DISTRICT	OS						
6	WESTERN AREA POWER							
7	ADMINISTRATION	OS			2,256			2,256
8	CALIFORNIA-OREGON							
9	INTERTIE	OS					357,499	357,499
10	OTHER	OS						
11								
12								
13								
14								
15								
16								
	TOTAL				151,374		798,111	949,485

Schedule Page: 332 Line No.: 2 Column: g

Represents payments for operations and maintenance costs.

Schedule Page: 332 Line No.: 3 Column: e

Represents payments for lease of transmission capacity.

Schedule Page: 332 Line No.: 3 Column: g

Represents payments for operations and maintenance costs.

Schedule Page: 332 Line No.: 7 Column: e

Represents payments for lease of transmission capacity.

Schedule Page: 332 Line No.: 9 Column: g

Represents payments for administrative costs of scheduling services provided by the California Independent Systems Operator (CAISO).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	7
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	
6	Clearing Account Adjustments	935,948
7	Intervenor Compensation	6,062,538
8	MCI-PG&E Exchange Rights	691,661
9	Bank Service Fees	3,097,911
10	Consulting Serv, Outside Attorney Fees, Contracts	220,882
11	Union Negotiation Adjustment	164,631
12	Non-PO Credit Memo's	-49,525
13	Misc cash receipt (recovery of unclaimed funds)	-86,289
14	Write off from miscellaneous reconciliations	-20,072
15	Other miscellaneous adjustments	-282
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46	TOTAL	11,017,410

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,613,762		2,613,762
2	Steam Production Plant	20,001,934				20,001,934
3	Nuclear Production Plant	263,150,322			38,731,572	301,881,894
4	Hydraulic Production Plant-Conventional	75,375,746			4,752,000	80,127,746
5	Hydraulic Production Plant-Pumped Storage	12,377,607			2,280,000	14,657,607
6	Other Production Plant	47,195,594				47,195,594
7	Transmission Plant	305,450,082				305,450,082
8	Distribution Plant	1,217,489,436				1,217,489,436
9	Regional Transmission and Market Operation					
10	General Plant	30,605,965				30,605,965
11	Common Plant-Electric	149,778,194		177,029,941		326,808,135
12	TOTAL	2,121,424,880		179,643,703	45,763,572	2,346,832,155

B. Basis for Amortization Charges

The basis used to compute the charges is the ending plant balance. The basis is different from the preceding year due to net plant additions throughout the year. The rates have been updated in accordance with 2017 GRC authorized rates.

The rates used to compute amortization charges for 'Intangible Plant – Electric' (Account 404) are as follows:
EIP30201 Intangible Plant: Franchise 2.19%; EIP30301 Intangible Plant: USBR 0%; EIP30303 Intangible Plant: Software 2.11%

The rates used to compute amortization charges for 'Common Plant – Electric' (Account 404) are as follows:
CMP30302 Intangible Plant: Software 21.45%; CMP30304 Intangible Plant: Software 6.61%

For FERC reporting purposes, common amortization expense is allocated to electric and gas amortization as common amortization expense is not reported on the FERC forms. The rate used to allocate the common amortization expense to electric is 64.65%.

Amortization of the Other Electric Plant (Account 405) - These amortization amounts represent the 2017 GRC authorized amounts to record for the recovery of the URG regulatory asset. In connection with the Chapter 11 Settlement Agreement, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities or recovery period, consistent with the period over which the related revenues are recognized.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Prod - Fossil						
13	310.02	4,801			2.18	SQ	
14	311	113,671	75.00		3.46	R1	19.70
15	312	277,962	50.00		3.69	R1	18.90
16	313						
17	314	257,380	40.00		3.56	R2.5	19.30
18	315	52,626	45.00		3.55	R2.5	19.70
19	316	28,349	40.00		3.77	S0.5	18.20
20	Subtotal	734,789					
21							
22	Hydraulic Production						
23	330	17,311			1.90	SQ	
24	331	525,846	80.00	-2.00	1.72	R2	13.80
25	332	2,124,218	120.00	-3.00	1.60	R2.5	18.30
26	333	1,007,802	81.00	-3.00	3.10	R1	14.60
27	334	296,609	65.00	-6.00	3.03	R1.5	15.70
28	335	102,422	60.00	-9.00	3.39	S0.5	15.60
29	336	93,136	88.00	-2.00	2.48	S1.5	17.10
30	Subtotal	4,167,344					
31							
32	Nuclear Prod - Diablo						
33	321	1,085,290	100.00	-1.00	1.55	R1	6.30
34	322	3,569,330	65.00	-1.00	2.70	S1	5.90
35	323	1,172,601	50.00	-1.00	1.54	S2	5.60
36	324	844,039	75.00		1.60	R1.5	6.10
37	325	1,152,130	50.00	-1.00	5.69	S1	6.20
38	Subtotal	7,823,390					
39							
40	Other Production						
41	340.02	3,121			0.64	SQ	
42	341	210,804	59.00		3.69	R1,SQ	19.60
43	342	11,271	50.00		3.69	R1	19.00
44	343	227,881	40.00		3.57	R2.5	19.50
45	344	353,878	27.00		4.35	R2.5,SQ	18.40
46	345	213,715	31.00		5.71	R2.5,S2.5,SQ	15.60
47	346	98,646	35.00		3.84	S0.5,SQ	18.30
48	Subtotal	1,119,316					
49							
50	Transmission						

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	350.02	247,241	42.00		4.06	R4	26.30
13	352	536,335	65.00	-20.00	1.80	R3	55.50
14	353	6,478,163	2.00		0.08	R1.5	0.80
15	354	961,640	75.00	-66.00	2.25	R4	55.30
16	355	1,384,181	52.00	-65.00	2.99	R1.5	42.60
17	356	1,670,014	65.00	-70.00	2.57	R2	49.30
18	357	511,098	65.00		1.52	R4	53.80
19	358	274,014	55.00	-10.00	1.99	R3	42.00
20	359	103,204	60.00	-10.00	1.91	R1.5	50.90
21	Subtotal	12,165,890					
22							
23	Transmission - Diablo						
24	352.01	4,891	65.00		1.43	R3	6.40
25	353.01	89,972	98.00	-19.00	7.05	R2	12.30
26	Subtotal	94,863					
27							
28	Distribution						
29	360.02	122,527	41.00		2.12	SQ	19.30
30	361	323,045	65.00	-20.00	1.78	R3	46.50
31	362	3,514,657	46.00	-40.00	3.06	R1.5	32.50
32	363	33,497	15.00		6.46	R2,S3	9.20
33	364	4,847,361	44.00	-150.00	6.03	R1.5	30.90
34	365	4,776,896	46.00	-125.00	5.05	R2	31.60
35	366	3,001,225	62.00	-50.00	2.60	R4	43.80
36	367	4,804,342	47.00	-65.00	3.35	R3	30.80
37	368	3,790,010	32.00	-28.00	4.40	R2.5,R3	21.00
38	369	3,423,955	47.00	-67.00	3.50	R2.5,R4	27.50
39	370	1,201,281	20.00	-15.00	6.21	R1.5	13.20
40	371	28,071	39.00	-1.00	0.09	S1	4.60
41	372	895	25.00			L1	
42	373	254,680	28.00	-23.00	3.25	R0.5,S1.5,L0,S1	10.00
43	Subtotal	30,122,442					
44							
45	General Plant						
46	389.02	415	59.00		2.74	SQ	30.90
47	390	11,777	50.00	-10.00	1.62	R2	30.40
48	391	10,927	20.00		6.20	SQ	10.90
49	394	145,209	25.00		3.85	SQ	17.30
50	395	15,907	20.00		5.37	SQ	12.90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	396						
13	397	351,873	15.00		6.25	SQ	12.50
14	398	25,736	20.00		13.04	SQ	17.20
15	Subtotal	561,844					
16							
17	General Plant Diablo						
18	391.01	4,504	20.00		5.23	SQ	16.50
19	398.01	15,863	20.00		5.39	SQ	15.90
20	Subtotal	20,367					
21							
22	Total	56,810,245					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Annual fees paid for Diablo Canyon Power Plant				
2	in accordance with Part 171				
3	Docket 5000133	47,000		47,000	
4	Docket 5000275	4,493,628		4,493,628	
5	Docket 5000323	4,493,628		4,493,628	
6					
7	Fees paid for Diablo Canyon Power Plant				
8	for inspection, license renewal, operator				
9	examination in accordance with Part 170				
10	Docket 5000275	1,020,279		1,020,279	
11	Docket 5000323	1,072,415		1,072,415	
12	General Accrual	-195,000		-195,000	
13					
14	Fees paid for Diablo Canyon Power Plant				
15	for inspection, license renewal, operator				
16	examination in accordance with Part 170				
17	Docket 5000275	61,766		61,766	
18	Docket 5000323	66,415		66,415	
19	General Accrual	-100,000		-100,000	
20					
21	Fees paid for Diablo Canyon Power Plant				
22	for inspection, license renewal, operator				
23	examination in accordance with Part 170				
24	Docket 7200026	69,498		69,498	
25					
26	Fees paid for Diablo Canyon Power Plant				
27	for inspection, license renewal, operator				
28	examination in accordance with Part 171				
29	Docket 5000275	46,122		46,122	
30	Docket 5000323	46,122		46,122	
31	General Accrual	40,000		40,000	
32					
33	Annual fees paid for Humubolt Bay Power Plant				
34	in accordance with Part 171				
35	Docket 5000133	153,500		153,500	
36					
37	*All paid to US Nuclear Regulatory Commission				
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	11,315,373		11,315,373	

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
							2
	524	47,000					3
	524	4,493,628					4
	524	4,493,628					5
							6
							7
							8
							9
	524	1,020,279					10
	524	1,072,415					11
	524	-195,000					12
							13
							14
							15
							16
	532	61,766					17
	532	66,415					18
	532	-100,000					19
							20
							21
							22
							23
	107	69,498					24
							25
							26
							27
							28
	101						29
	101						30
	101						31
							32
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	524	153,500					35
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		11,183,129					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A2, A3	Electric Program Investment Charge
2		
3		
4		
5		
6	A2, A3	Customer Energy Services -
7		Cyber Security and Grid Innovation
8		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
10,284,310		408	250,978		1
		456	-193,037		2
		588	9,483,988		3
		926	742,381		4
					5
3,501,062		408	27,430		6
		588	3,416,438		7
		908	-23,918		8
		926	81,112		9
					10
					11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	330,993,100		
4	Transmission	79,824,930		
5	Regional Market			
6	Distribution	175,719,058		
7	Customer Accounts	113,609,934		
8	Customer Service and Informational	56,998,283		
9	Sales	651,164		
10	Administrative and General	216,549,578		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	974,346,047		
12	Maintenance			
13	Production	99,428,025		
14	Transmission	38,444,457		
15	Regional Market			
16	Distribution	171,069,015		
17	Administrative and General	3		
18	TOTAL Maintenance (Total of lines 13 thru 17)	308,941,500		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	430,421,125		
21	Transmission (Enter Total of lines 4 and 14)	118,269,387		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	346,788,073		
24	Customer Accounts (Transcribe from line 7)	113,609,934		
25	Customer Service and Informational (Transcribe from line 8)	56,998,283		
26	Sales (Transcribe from line 9)	651,164		
27	Administrative and General (Enter Total of lines 10 and 17)	216,549,581		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,283,287,547		1,283,287,547
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	2,634,683		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	5,539,415		
35	Transmission	96,675,038		
36	Distribution	158,177,895		
37	Customer Accounts	74,115,974		
38	Customer Service and Informational	14,454,403		
39	Sales	608,866		
40	Administrative and General	105,505,118		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	457,711,392		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)	249,993		
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,552,205		
47	Transmission	55,191,848		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	84,850,684		
49	Administrative and General	1		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	141,844,731		
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,	2,884,676		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	7,091,620		
56	Transmission (Lines 35 and 47)	151,866,886		
57	Distribution (Lines 36 and 48)	243,028,579		
58	Customer Accounts (Line 37)	74,115,974		
59	Customer Service and Informational (Line 38)	14,454,403		
60	Sales (Line 39)	608,866		
61	Administrative and General (Lines 40 and 49)	105,505,119		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	599,556,123		599,556,123
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	1,882,843,670		1,882,843,670
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	781,939,241		781,939,241
69	Gas Plant	422,493,640		422,493,640
70	Other (provide details in footnote):	158,619,223		158,619,223
71	TOTAL Construction (Total of lines 68 thru 70)	1,363,052,104		1,363,052,104
72	Plant Removal (By Utility Departments)			
73	Electric Plant	65,534,708		65,534,708
74	Gas Plant	25,198,754		25,198,754
75	Other (provide details in footnote):	1,065,193		1,065,193
76	TOTAL Plant Removal (Total of lines 73 thru 75)	91,798,655		91,798,655
77	Other Accounts (Specify, provide details in footnote):			
78	Other Balance Sheet Salaries and Wages	13,605,364		13,605,364
79	Other Non-Operating Salaries and Wages	10,690,997		10,690,997
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	24,296,361		24,296,361
96	TOTAL SALARIES AND WAGES	3,361,990,790		3,361,990,790

Schedule Page: 354 Line No.: 70 Column: b

Represents Common Plant

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.

COMMON UTILITY PLANT IN SERVICE

Acct No.	Description	Balance Beginning of Year	Additions	Transfers and Retirements	End Adjustments	Balance of Year
301	Organization	132,411	997	0	(997)	132,411
302	Franchises/Consents	214,735	0	0	0	214,735
303	Intangible Plant	1,689,092,237	195,843,124	(290,220,071)	0	1,594,715,290
	Total Intangible Plant	1,689,439,383	195,844,121	(290,220,071)	(997)	1,595,062,436
389	Land and Land Rights	91,241,687	13,145,387	0	(27,639)	104,359,435
390	Structures and Improvements	1,657,025,235	174,589,367	(198,396)	0	1,831,416,206
391	Personal Computer Hardware	94,231,910	11,356,419	(32,650,708)	0	72,937,621
391	Office Machines	320,722,501	71,645,048	(70,923,780)	997	321,444,766
391	Office Furniture and Equipment	119,333,965	4,462,818	(2,568,691)	0	121,228,092
392	Transportation Equipment	1,068,627,787	53,641,339	(41,718,944)	0	1,080,550,182
393	Stores Equipment	9,418,244	307,799	(9,721)	0	9,716,322
394	Tools, Shop, and Garage Equipment	68,889,594	897,918	0	0	69,787,512
395	Laboratory Equipment	9,794,188	3,789,423	(160,165)	0	13,423,446
396	Power Operated Equipment	177,613,797	2,597,075	(3,126,781)	0	177,084,091
397	Communication Equipment	1,171,430,168	78,490,136	(33,491,788)	0	1,216,428,516
398	Miscellaneous Equipment	41,357,926	(12,288,261)	(360,798)	0	28,708,867(a)
399	Other Tangible Property	679	0	0	0	679
	Total Non-Landed	4,738,445,994	389,489,081	(185,209,772)	997	4,942,726,300
	Total	6,519,127,064	598,478,589	(475,429,843)	(27,639)	6,642,148,171
101	Property Under Capital Leases	18,230,721	0	0	0	18,230,721
101	Plant Purchased/Sold	0	0	0	0	0
	Total Common Utility Plant in Service	6,537,357,785	598,478,589	(475,429,843)	(27,639)	6,660,378,892
107	Construction Work in Progress - Common Utility Plt.	398,724,501	101,003,688	0	(11,448,712)	488,279,477

COMMON UTILITY PLANT AND EXPENSES

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Total Common Utility Plant	6,936,082,286	699,482,277	(475,429,843)	(11,476,351)	7,148,658,369

NOTES:
(a) Included in the 12/31/18 FERC account 398 plant balance is $13,874,119 in Operative CWIP. Operative CWIP is defined as capital orders that are less than 30 days of construction that remain in CWIP due to capital order settlement issues. Capital orders that are less than 30 days of construction should be classified as plant. Since we may not know the final settlement of operative CWIP orders, FERC account 398 is chosen as a temporary settlement until these orders have valid settlement rules.

ALLOCATION OF COMMON UTILITY PLANT AND ACCUMULATED PROVISION FOR DEPRECIATION BASED ON THE COST SEPARATION ADOPTED BY THE CPUC

Description	Total	Electric	Gas
Common Utility Plant in Service (a)	6,660,378,892	4,306,079,230	2,354,299,662
Accumulated Provision for Depreciation (a)	2,742,082,239	1,779,611,373	962,470,866

ALLOCATION OF AD VALOREM TAXES APPLICABLE TO COMMON UTILITY PLANT BASED ON THE COST SEPARATION ADOPTED BY THE CPUC

Description	Amount Charged During Year	Account 408 Electric	Account 408 Gas
Taxes			
Operative Property (b) (from page 262-263)	470,923,474	355,559,961	115,363,513
Common Utility Plant (a) included in above amount	41,199,088	26,636,103	14,562,985

NOTES:
(a) 2018 allocations are based on the methodology of unbundling Common Plant as approved in the cost separation filing and adopted in the 2017 General Rate Case (GRC).

COMMON UTILITY PLANT AND EXPENSES

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	Electric	Gas
Common Plant in Service Allocation Factors	64.65%	35.35%
Common Plant Accumulated Depreciation Allocation Factors	64.90%	35.10%

(b) Amounts are based on direct charges. Not included in the total was $486,744 charged to others.

ALLOCATION OF DEPRECIATION EXPENSE APPLICABLE TO COMMON
UTILITY PLANT BASED ON THE COST SEPARATION ADOPTED BY THE CPUC

Description	Account	Amount Charged During Year	Account 403 Electric	Account 403 Gas
Depreciation	403	230,783,041	149,778,194	81,004,847
Amortization	404	272,773,407	177,029,941	95,743,465
Total		503,556,448	326,808,135	176,748,312

ALLOCATION OF MAINTENANCE EXPENSES OF COMMON UTILITY
PLANT BASED ON THE COST SEPARATION ADOPTED BY THE CPUC

Description	Amount Charged During Year	Account 935 Electric	Account 935 Gas
Maintenance of General Plant	6,979,178	4,725,363	2,253,815

Note: Operation expense data was not available.

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

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CONSTRUCTION WORK IN PROGRESS (CWIP) - COMMON (ACCOUNT 107)

Description of Project		Amount
7086328	Merced SC - Building B RMC	25,470,786.81
70032940	ITSM Remedy Upgrade	11,233,417.20
74017024	SAP Roadmap Foundational Upgrade	10,634,902.32
7092050	77 Beale GO-8th,27th Flrs Refresh (IO)	9,531,565.98
70036182	CC2020 Salesforce - Cap	8,954,872.46
74017181	Endur Upgrade Ph2	8,122,463.71
7090505	Corp Security-Replacement of Legacy CCTV	7,818,043.41
7094507	Wildfire Helicopter - N605PG	7,740,308.76
7094508	Wildfire Helicopter - N606PG	7,740,308.74
7092090	Concord SC - Refresh Program - Area 2	7,648,206.39
7094505	Wildfire Helicopter - N603PG	7,336,051.00
7094506	Wildfire Helicopter - N604PG	7,336,051.00
70028908	DR - Meter Data Management System (MDMS)	7,145,571.08
7092306	Facility Asset Upkeep - Area 2	6,981,302.46
7091299	VCOC - B1 Expansion	6,940,572.18
7091625	System ETI-Trailer Upgr Pgrm (2017)	6,676,962.64
7092311	Facility Asset Upkeep - Area 6S	6,591,120.67
7090331	San Francisco SC - Security Program	6,443,961.41
7092307	Facility Asset Upkeep - Area 3	6,297,356.19
7091106	Merced LNG - Tanker Relocation	5,694,832.98
70035445	IO - SmartMeterSSN Transition PG&E (CAP)	5,342,738.14
70036866	MRAD Platform 2.0 Cap	5,309,965.30
70036060	IO - Cloud Enablement - Cloud Mgmt Pltfr	5,203,189.01
7092288	Service Center Refresh Program - Area 6	5,166,011.23
7093047	Stockton Mat'l Lease Optimization_B	5,055,443.63
7092292	Facility Asset Upkeep - GO	4,827,524.03
70035220	ST - Security Enclave (CAP)	4,766,238.02
70036224	Communication-FAN	4,715,963.42
70035405	Increase Self Service Adoption - Cap	4,629,065.40
7089806	Bay Area Program - GO (CAR 1C)	4,355,922.46
70036900	ARAD 3.0 Cap	4,231,497.54
70033583	OP: AMSM-Asset Mgmt Pltfrm & Srvcs (AMPS	4,223,627.20
7092045	SFGO - Conference Rooms Refresh (IO)	4,132,344.83
70034968	IO - Pure Flex Remediation	4,014,403.36
7092293	Burney SC - Security Program - Area 6	3,965,318.63
7091574	Network Improvements - Add Alternate	3,946,983.76
74017094	SQMD Replacement Phase 3	3,944,987.23
7091946	Stockton Regional Ofc-Upgrades (PH2)_PV	3,716,796.57
70037840	Locate & Mark (GRCGD) - CAP	3,665,922.84
7093670	CSO Security Upgrades (75 Sites) Ph2	3,456,134.91

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7091451	Facility Asset Upkeep Break/Fix	3,347,134.46
7092785	DMS Upgrade	3,346,124.60
70035024	ST-Web Acc Mgmt (CA Sitemndr) Rep (CAP)	3,315,174.09
70035562	Meter Data Mgmt Sys Upgrade R1 - Cap	3,239,156.47
70033757	Substation Record and RecordKeeping Impr	3,188,932.09
7087511	Antioch SC - Renovation	3,184,128.72
7092312	Facility Asset Upkeep - Area 7	3,087,563.81
7092310	Facility Asset Upkeep - Area 6N	3,032,174.99
70035507	IO - ECP IP Trade Turret Infra Upgrd	3,024,454.11
70035661	DC - OSI PI Platform Capacity Phase 3 -	2,943,316.38
7092286	Bkfld,SMaria,TemplSC-Refresh Prog--Area4	2,942,751.94
7091572	GTCC Predictive Health Analytics	2,841,846.89
7091945	FM Energy Efficiency Upgrade Program	2,809,193.17
7093625	LOB Ofc Optimiz Pgm - Edenvale/SLO	2,747,715.36
7091785	77 Beale GO - Mech Upgrd - Flrs 11-15-16	2,742,656.54
7092289	Service Center Refresh Program - Area 7	2,721,779.88
74017086	FFMO CAP	2,717,338.21
70033741	Express Connects Cap	2,582,960.98
7092505	CSO Head Cashier Ofc Renovation Program	2,556,234.49
7092285	Service Center Refresh Program - Area 3	2,535,246.23
70036262	SSN Wildfire Data Queries (Cap)	2,460,391.13
70037185	Inspect and Maintain (AI 2.0) (ED) - Cap	2,453,971.22
70037184	Inspect and Maintain (AI 2.0) (GD) - CAP	2,446,393.33
70030413	Cyber: Windows XP Migration CAP Transmis	2,446,280.55
74017084	Enterprise Compliance Management Tool CA	2,434,730.46
7092287	Sonora SC - Refresh Program - Area 5	2,363,155.15
70037187	Inspect and Maintain (AI 2.0) (TO) - CAP	2,344,495.64
70036143	EES Ph2 (CAP)	2,281,640.83
7090825	Corp Security-SIS Replacement-Capital	2,230,695.03
74017099	Hat Creek Network Extension	2,183,672.96
7093946	Lemoore Flt - Mtc Bldg & Wash Station	2,182,500.73
70032961	CIP003-WP04A Low Impact Methodology	2,156,929.51
70037186	Inspect and Maintain (AI 2.0) (GTS) - CA	2,149,323.51
70033421	Corrective Maintenance (GRCED) - Cap	2,125,387.18
70033422	Corrective Maintenance (GRCGD) - Cap	2,116,197.53
7092265	San Francisco SC - Refresh Prog - Area 1	2,103,531.47
70033756	Bentley SAP Integration - Phase3	2,080,155.79
7092249	System - SC Security Program - Area 3	2,051,921.37
7091345	SFGO - Elec Upgrd (Controls & Alarms)	2,018,452.85
7092025	LOB Office Optimization Program	2,013,764.09
74017090	ESOMS Upgrade CAP	1,945,841.67
70037327	CWSP: WSOC Monitoring and Decision Supp	1,900,985.57
7092305	Facility Asset Upkeep - Area 1	1,875,462.36
70029346	Wesley Fiber Install	1,871,332.89
70037821	CES - Contact Ctr Hardware Purchases (C)	1,854,166.10
70035642	JUMP (Cap)	1,853,199.30

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7093891	ADMS Phase 0 Cap	1,852,606.54
7090645	System ETI - Trailer Upgrade Program_C	1,762,524.79
74017091	DCPP Replace EDMS/RMS/Filenet PH2	1,743,552.37
7091573	GDCC Predictive Health Analytics	1,707,440.83
70035502	ST - 2018 Lifecycle Replacement (Cap)	1,653,969.13
70036261	Transmission Support Structures (CAP)	1,649,312.81
70036780	Trans Support Structures GRC (CAP)	1,642,866.33
70037462	IO - Digital Mobile Radio (DMR) Backend	1,591,359.00
70037463	CRCR Release 2 - BT CAP	1,575,854.66
70036222	Cybersecurity	1,567,244.26
7092308	Facility Asset Upkeep - Area 4	1,559,843.11
70029487	2015 Oracle DB_Audit Rem & Data Sec Enh	1,521,165.84
74016901	Consolidate PGEN PPM into EPPM.	1,460,029.77
7092290	Fresno CSO - Security Program - Area 4	1,380,382.06
74017920	NEWVMS CAP	1,318,768.86
70034495	Vulnerability Management Program	1,302,306.71
7090325	Auburn SC Regional GC Conversion	1,298,304.09
70038048	IO - Smart Meter Field Assets Lifecycle	1,252,096.23
74017496	Enabling Online HR CAP	1,240,525.51
70036482	ARI Enhancements Capital	1,207,324.60
70037086	IGP - SCADA -MT Top Radio Masters	1,185,705.94
7092294	Ukiah SC - Security Program - Area 7	1,171,966.04
70036940	EGI 2018 Tariff Changes	1,153,479.17
70037080	IO - Data Center Consolidation Storage	1,120,855.35
70032529	Linear Inspection (ED) - CAP	1,118,926.40
70026860	Table Mtn Sub Fiber Install	1,115,801.07
70036742	IO - WIFI Everywhere-Field Ph 2 - W2	1,095,457.86
7093893	CSO - Install Bullet Resistant Glass PH1	1,090,292.01
70035480	Automation of FAA Obstruction Evaluation	1,063,641.01
7092246	Antioch/Oakland SC-Security Prog Area 2	1,057,385.04
74017088	Lease Standard Implementation CAP	1,045,915.58
70037720	IO - D305 - D306 DMW Replacement	1,045,711.92
70035542	IO - WAN WAAS Optimization	1,025,360.53
74017560	Model Platform P5 CAP	1,020,949.65
7074466	Tracy Sub to Bethany Cmprsr Stn Fbr Bld	1,016,723.19
70035741	Heavy Bid to SAP (Cap)	1,003,075.36
70030697	D080 SLO SC to Black Butte	983,568.43
7092965	15 Sites - Critical Substations Tier 1 2	978,023.32
70036161	Compliance Asset Data Reporting (CAP)	958,844.68
70033549	Cyber SS ST - 3rd Party Security and Ris	914,743.22
70035447	DCPP Network Switch and WiFi Replacement	881,640.48
7091575	Network Improvements - Improve WAN	866,268.67
70032902	Fiber Cable - Sacramento Fiber Cable Rep	858,677.09
74018245	MII ESDER 2	847,067.71
70036021	Data Security Data De-Identification (Ca	843,225.95
70036042	DR - Set 9 Disaster Recovery Project (CA	831,368.32

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

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

74018242	MII Fall 2018	819,190.98
74017097	Power Gen Records Management - cap	780,516.66
7086212	77 Beale GO - Mech Upgrd(Fans 6-7-11-12)	754,044.31
7088763	Electric Storage Containers	744,535.16
70036027	Data Security Metrics, Inventory, Owners	739,402.95
70033814	Bentley-SAP Integration CAP ET Phase 3	731,456.15
70036360	CYME LoadSEER and EDPI Integration	731,070.41
70036023	Data Security DLP Expansion (Cap)	725,611.38
74017106	Kings-Crane Grounding and Bonding	724,383.82
70037540	IGP Communication-Control/Data Center v2	721,306.79
7083729	TO Radio System Expansion - Gato Ridge	718,959.93
70033419	Corrective Maintenance (TO) - Cap	707,929.99
70033420	Corrective Maintenance (GT&S) - Cap	707,929.99
70035023	Lvl 3 Lat Bld-Eastshore Sub	706,490.38
70035662	DC - OSI PI Platform Capacity Phase 3 -	681,375.73
74018957	FBS Upgrade	680,536.47
70033697	Gas Qualification - System Data Automati	665,143.85
7092999	12 Servers - NEW AMAG Servers	660,433.93
7091300	VCOC - B1 Expansion_I	646,393.91
74017111	Wireless Enhancements - Feather	640,961.38
70036204	CCSF - (CAP)	636,312.92
7092051	77 Beale GO-8th,27th Flrs Refresh_I (IO)	599,841.31
70029805	Black Butte to Red Rock Mountain PTP Upg	593,335.97
7083653	Radio Reliability - Carmel Valley	582,191.06
70036326	Cloud Security Automation (CAP)	581,858.46
70030780	Motherlode - VoIP	579,821.51
7092245	Colma SC - Security Program - Area 1	575,810.04
70036283	IO - 2018 Switch Lifecycle	572,359.54
70034662	Lights Out Management	562,205.22
70033129	NEM 2.0 Customer Bill Presentment Cap	557,636.95
70032183	D110 (Morro Bay - Tassajara)	532,861.08
70036847	IGP - FAN - South	529,058.63
70031025	DS0 Migration Project Phase II (Testing)	521,869.38
70036480	Access Request and Review Capital	520,688.97
70033771	OP: AMSM - Enterprise Network Mgmt Syst	515,426.22
70037131	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP HG	512,918.91
70037127	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP TO	512,918.84
70037128	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP ED	512,918.84
70037129	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP GD	512,918.84
70037130	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP IT	512,918.84
70036043	IO - Cloud Enablement - Networking	501,506.12
70027586	Radio Reliability - Lime Mt	491,585.38
70031243	Inspect - Canal (HG) - CAP	487,702.27
70036600	IO-2018 ODN Cap Incrs Reliab Imprv (TO)	460,330.68
70033147	Pole Loading Tool Upgrade with Industry	456,506.12
70036226	Communication-SCADA	445,147.71

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

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

70036381	FIP - Marysville Warehouse	439,697.04
7089807	Bay Area Program - GO_I (CAR 1C)	439,443.69
70037921	IO - Total Cost of Ownership (Cap)	434,376.68
70037088	IGP - SCADA -ODN Upgrades	434,277.95
7093845	Bay Area Optimization Pgm-East Bay PH 1	424,800.07
74019740	RPM Wave 2 CAP	421,712.90
7093305	Spacefinder Program	403,672.95
70033562	Hughes Satellite Terminal Replacement	380,864.70
70037082	IGP - SCADA - Digi Upgrades	374,305.25
7094205	ADMS SI Planning	374,147.97
70032800	Battle Creek - VSAT Emergency Phones	372,005.87
70034622	Hinkley Comp Station Ntwrk Remediation	363,299.12
70032184	D115 (Davis Peak-Morro Bay)	359,609.45
7092046	SFGO - Conference Rooms Refresh_I (IO)	358,522.75
74017108	Kings-Crane Network Extension	358,450.03
70036741	IO - WIFI Everywhere-Field Ph 2 - W3	352,036.26
70037326	CWSP: Vegetation Mgmt Data Enablement C	342,737.28
70034962	Lvl 3 Lat Bld-Brlngm Sub/San Crls/Mv Sub	335,731.47
70037405	CWSP: Maps+ for Emergency Mgmt (ED) CAP	331,359.22
70037407	CWSP: Maps+ for Emergency Mgmt (HG) CAP	323,455.04
70037408	CWSP: Maps+ for Emergency Mgmt (GT&S) C	323,455.04
70037409	CWSP: Maps+ for Emergency Mgmt (TO) CAP	323,455.04
70037406	CWSP: Maps+ for Emergency Mgmt (GD) CAP	323,454.88
7091752	Auburn Garage - Two Lifts	319,250.84
70036795	IO - CF - FFIOC	318,066.50
70029581	EMS SMP Server Replacement	312,970.90
70036327	Advanced Security Svcs for O365 (CAP)	307,293.72
70032303	Bentley-SAP Integration CAP ED	306,913.00
70036041	IO-AMSM-SCCM ODN-Windows 10/Server 2016	306,737.34
70037482	CWSP: Bill Ops Atmation for Mjr Evnt - C	297,446.35
7092291	System - SC Security Program - Area 5	295,938.93
70033696	Cimplicity to PI for Compressor Stations	295,410.69
70031242	Linear Inspection (Prev ET) - CAP	293,667.87
70032182	D111 (Tassajara to EOF)	292,608.05
70037084	IGP - SCADA - Masters	290,427.52
70036380	IO - SCADA Power Reliability: Table Mtn.	288,943.83
7093000	245 Market Lobby Turnstiles	288,327.96
7093307	Livermore - Transformer Lab Building	286,055.83
7092309	Facility Asset Upkeep - Area 5	285,730.48
70037126	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP GT	284,954.95
74017115	DCPP Remediate Vulnerable Operating Sys	280,884.19
7093807	DREBA2017-R24 CLICKTHRU-P3-IT-Sol3-CAP	279,807.61
7091750	30k Drive on Hoist	278,640.80
70033563	IO - SCADA Power Reliability: TES Facili	277,263.04
70032181	D112 (EOF to Black Butte)	275,880.65
74017103	Drum - VoIP	273,712.82

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.
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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.

```
70036540    IO-ZAYO-Newark to Sunol Y Rstr(ADSS Ph1)        273,010.68
70036025    Data Sec Governance Access Remediation      268,225.08
7091108     Materials & Spoils Bay Covers                   267,678.52
7093545     ESP Improvement Project                         265,576.48
70036213    IO - Digital Mobile Radio (DMR) Backend         264,429.26
7092805     Fresno Thorne Avenue - Develop OU-3             257,746.81
70031540    Hydro HVP Program                               257,210.99
74017114    PGEN Station Tech Upgrade Program               254,510.16
70036208    IO -Develop Fiber Mux Platform to Replac        253,436.07

                                                          -------------

Subtotal - Projects with more than $250,000
  in actual costs in CWIP, excluding Research,
  Development, & Demonstration jobs                   $ 478,291,300.57


Aggregate total of projects with less than $250,000 in actual
  costs in Construction Work in Progress, including credits
  representing preliminary billings.

                                                      $   9,988,176.00
                                                         --------------

        TOTAL CWIP - COMMON                           $ 488,279,477.56
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	91,388,877	65,382,174	43,094,470	261,565,491
3	Net Sales (Account 447)	(8,123,190)	(14,078,638)	(195,984,093)	(344,978,739)
4	Transmission Rights				
5	Ancillary Services	(2,358,942)	(2,043,552)	(6,946,921)	(12,794,035)
6	Other Items (list separately)				
7	Grid Management Charges	10,595,990	11,254,478	13,252,982	45,707,324
8	FERC Fees	1,047,892	988,383	1,172,575	4,020,007
9	ISO Congestion				
10	Unaccounted for Energy	5,331,131	(7,649,507)	1,430,485	5,984,445
11	Congestion Revenue Rights-Hedge	6,984,607	(4,282,099)	(6,499,743)	(12,298,389)
12	Congestion Revenue Rights-Auction	(623,720)	(418,311)	(4,716,222)	(6,731,613)
13	Convergence Bidding	28,243	166,886		195,129
14	Other ISO-related charges:				
15	Minimum Load				
16	Neutrality	(150,330)	22,028	286,069	(122,929)
17	Voltage Support				
18	Other	3,638,725	3,786,149	8,625,911	20,246,014
19	Cost Recovery	(1,012,384)	(1,052,640)	5,084,223	2,004,244
20	Inter Day Ahead SC Trade				
21	Inter Real Time SC Trade				
22	Interest	209,893	216,943	103,343	691,342
23	Capacity - Other	388,198	4,332,938	3,583,688	10,656,463
24	DA IFM Credit Allocation	(8,073,047)	(8,444,673)	(21,072,175)	(47,945,298)
25	RT Offset/Allocation	5,618,045	5,215,103	19,989,516	31,748,255
26	Net Purchases for Energy Storage	(58,374)	(153,238)	(22,917)	(220,207)
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	104,831,614	53,242,424	(138,618,809)	(42,272,496)

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch					N/A	
2	Reactive Supply and Voltage					kW-Month	
3	Regulation and Frequency Response					kW-Month	
4	Energy Imbalance					kWh	
5	Operating Reserve - Spinning					kW-Month	
6	Operating Reserve - Supplement					kW-Month	
7	Other		Various	1,878,331		Various	14,672,366
8	Total (Lines 1 thru 7)			1,878,331			14,672,366

Schedule Page: 398 Line No.: 1 Column: b

All Ancillary Services (AS) purchases and sales are covered under the FERC approved ISO Tariff. Definitions of AS under Order No. 888 and the ISO Tariff are not consistent with one another. In order to avoid confusion as to meanings and terminologies, ISO AS amounts are not included on these lines but are reported on Line 7.

Schedule Page: 398 Line No.: 7 Column: b

This line includes Ancillary Services as follows:

AS under grandfathered existing contracts						
Regulation Service Charge	-	-		-	Flat Charge	0
ISO related AS activities						
Retail/BART ISO Purchases and Sales and Existing Transmission Contracts (ETC) (a)	-	Various	1,878,331	-	Various	14,672,366
Total			1,878,331			14,672,366

(a) This comprised of various billing determinants which the ISO uses to calculate the amounts of AS sold or purchased.
This item also includes ISO AS purchases/sales by the Utility in its role as Scheduling Coordinator for ETCs.

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: PACIFIC GAS AND ELECTRIC COMPANY

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	13,520	8	1900	8,128			50		5,342
2	February	14,095	20	1900	8,911					5,184
3	March	13,009	5	2000	7,762					5,247
4	Total for Quarter 1				24,801			50		15,773
5	April	13,395	23	2100	7,404			60		5,931
6	May	16,268	29	1900	9,717			100		6,451
7	June	18,048	23	1900	10,439			100		7,509
8	Total for Quarter 2				27,560			260		19,891
9	July	18,973	25	1900	10,876			75		8,022
10	August	18,633	9	1900	10,338			75		8,220
11	September	16,455	7	1800	8,826			100		7,529
12	Total for Quarter 3				30,040			250		23,771
13	October	14,354	2	2000	6,778			100		7,476
14	November	13,142	14	1900	6,192			100		6,850
15	December	13,770	4	1900	5,165			100		8,505
16	Total for Quarter 4				18,135			300		22,831
17	Total Year to Date/Year				100,536			860		82,266

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	5,931,611
4	Nuclear	18,265,519
5	Hydro-Conventional	7,826,709
6	Hydro-Pumped Storage	784,053
7	Other	710,920
8	Less Energy for Pumping	1,212,365
9	Net Generation (Enter Total of lines 3 through 8)	32,306,447
10	Purchases	31,325,610
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	366,570
17	Delivered	359,638
18	Net Transmission for Other (Line 16 minus line 17)	6,932
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	63,638,989

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	49,516,473
23	Requirements Sales for Resale (See instruction 4, page 311.)	10,790,942
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	3,331,574
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	63,638,989

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: PACFIC GAS AND ELECTRIC COMPANY

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	5,029,823		11,901	8	1900
30	February	4,581,182		12,624	20	1900
31	March	4,859,705		11,406	5	2000
32	April	4,665,634		12,046	23	2100
33	May	5,154,051		14,705	29	1900
34	June	5,677,493		16,428	23	1900
35	July	6,634,933		17,263	25	1900
36	August	6,251,443		16,770	9	1900
37	September	5,383,907		14,729	7	1800
38	October	5,305,835		12,813	2	2000
39	November	4,841,750		11,642	14	1900
40	December	5,253,233		12,315	4	1900
41	TOTAL	63,638,989				

Schedule Page: 401 Line No.: 3 Column: b

This line includes combined cycle plants only. It does not include internal combustion reciprocating engines, which are included on Line 7.

Schedule Page: 401 Line No.: 7 Column: b

This line includes internal combustion reciprocating engines, photo voltaic and Fuel Cells. This includes photo voltaic generation of 310,219 MWh.

Schedule Page: 401 Line No.: 10 Column: b

For purposes only of accounting for the total energy that went through the Utility's electric system, the MWH for Direct Access ("DA") is 30,549,791 MWH. It should be noted that DA and DWR megawatts are not Utility purchases and were reported here only because page 401 of the Form 1 does not have any other available line where DA and DWR deliveries can be shown more appropriately.

The Utility acts as a pass-through entity for electricity purchased by the DWR that is sold to the Utility's customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from electricity revenue amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers, priced at the related CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Statement of Income.

Schedule Page: 401 Line No.: 22 Column: b

This includes MWH sales for DWR and DA as discussed in the footnote to Line 10, column b.

Schedule Page: 401 Line No.: 26 Column: b

Data for energy used by the Electric department is not separately available but is included on Line 22.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Diablo Canyon 1& 2* (b)			Plant Name: *Colusa Gen Station* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Outdoor		
3	Year Originally Constructed	1968			2010		
4	Year Last Unit was Installed	1986			2010		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2323.00			711.45		
6	Net Peak Demand on Plant - MW (60 minutes)	2240			657		
7	Plant Hours Connected to Load	8760			6088		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	2240			0		
10	When Limited by Condenser Water	2240			0		
11	Average Number of Employees	1303			22		
12	Net Generation, Exclusive of Plant Use - KWh	18265519000			2991759812		
13	Cost of Plant: Land and Land Rights	22726560			7889274		
14	Structures and Improvements	1089216494			115958181		
15	Equipment Costs	6783305893			544344962		
16	Asset Retirement Costs	2701010462			3912558		
17	Total Cost	1.059E+10			672104975		
18	Cost per KW of Installed Capacity (line 17/5) Including	4561.4548			944.6974		
19	Production Expenses: Oper, Supv, & Engr	4025966			257077		
20	Fuel	129114087			85252370		
21	Coolants and Water (Nuclear Plants Only)	37292499			0		
22	Steam Expenses	38815499			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1867685			3355754		
26	Misc Steam (or Nuclear) Power Expenses	334859486			687396		
27	Rents	0			0		
28	Allowances	0			16636516		
29	Maintenance Supervision and Engineering	2782594			70112		
30	Maintenance of Structures	3442055			1903977		
31	Maintenance of Boiler (or reactor) Plant	26816759			700898		
32	Maintenance of Electric Plant	36172375			2950795		
33	Maintenance of Misc Steam (or Nuclear) Plant	-83619837			3033692		
34	Total Production Expenses	531569168			114848587		
35	Expenses per Net KWh	0.0291			0.0384		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MWD			Mcf		
38	Quantity (Units) of Fuel Burned	2303440	0	0	20823676	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1039167	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	4.320	0.000	0.000
41	Average Cost of Fuel per Unit Burned	55.847	0.000	0.000	4.590	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.682	0.000	0.000	4.420	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.007	0.000	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	10327.208	0.000	0.000	7233.000	0.000	0.000

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

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

Plant Name: *Gateway Gen Station* (d)	Plant Name: *Humboldt Gen Station* (e)	Plant Name: (f)	Line No.
Combined Cycle	Internal Comb Recip		1
Outdoor	Indoor		2
2009	2010		3
2009	2011		4
619.65	162.70	0.00	5
580	163	0	6
6735	8643	0	7
0	0	0	8
0	0	0	9
0	0	0	10
22	19	0	11
2939850866	384780571	0	12
5040000	161399	0	13
72443812	67447178	0	14
383958736	152579352	0	15
3004029	1925852	0	16
464446577	222113781	0	17
749.5305	1365.1738	0	18
257077	78872	0	19
86205401	14613788	0	20
0	0	0	21
16174	0	0	22
0	0	0	23
0	0	0	24
3753644	3492951	0	25
896002	989204	0	26
0	0	0	27
16631614	2384413	0	28
70112	21510	0	29
59850	204863	0	30
703572	73824	0	31
3627718	5609397	0	32
1282815	0	0	33
113503979	27468822	0	34
0.0386	0.0714	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas			Oil	Gas					36
Mcf			Bbl	Mcf					37
20357260	0	0	2734	3225039	0	0	0	0	38
1041167	0	0	5795804	1040917	0	0	0	0	39
4.220	0.000	0.000	100.630	4.150	0.000	0.000	0.000	0.000	40
4.490	0.000	0.000	101.020	5.480	0.000	0.000	0.000	0.000	41
4.310	0.000	0.000	17.430	5.270	0.000	0.000	0.000	0.000	42
0.030	0.000	0.000	0.140	0.050	0.000	0.000	0.000	0.000	43
7210.000	0.000	0.000	8089.000	8885.000	0.000	0.000	0.000	0.000	44

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 1 (b)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1927	1958
4	Year Last Unit was Installed	1927	1958
5	Total installed cap (Gen name plate Rating in MW)	31.00	97.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	105
7	Plant Hours Connect to Load	7,972	8,727
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	34	105
10	(b) Under the Most Adverse Oper Conditions	34	104
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	82,111,021	401,299,232
13	Cost of Plant		
14	Land and Land Rights	8,165	2,630
15	Structures and Improvements	854,160	5,192,179
16	Reservoirs, Dams, and Waterways	9,448,057	7,126,485
17	Equipment Costs	9,802,804	38,968,422
18	Roads, Railroads, and Bridges	1,327,037	1,739,338
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	21,440,223	53,029,054
21	Cost per KW of Installed Capacity (line 20 / 5)	691.6201	545.5664
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	3,425	9,227
25	Hydraulic Expenses	10,255	31,671
26	Electric Expenses	141,901	222,402
27	Misc Hydraulic Power Generation Expenses	61,751	189,223
28	Rents	28,076	86,622
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	46,779	144,781
31	Maintenance of Reservoirs, Dams, and Waterways	76,354	217,457
32	Maintenance of Electric Plant	107,740	238,068
33	Maintenance of Misc Hydraulic Plant	491,536	1,369,778
34	Total Production Expenses (total 23 thru 33)	967,817	2,509,229
35	Expenses per net KWh	0.0118	0.0063

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 2105 Plant Name: BUTT VALLEY (b)	FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1921
4	Year Last Unit was Installed	1958	1924
5	Total installed cap (Gen name plate Rating in MW)	40.00	73.85
6	Net Peak Demand on Plant-Megawatts (60 minutes)	41	75
7	Plant Hours Connect to Load	4,736	6,717
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	41	75
10	(b) Under the Most Adverse Oper Conditions	38	74
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	57,118,200	110,532,743
13	Cost of Plant		
14	Land and Land Rights	398,183	330,012
15	Structures and Improvements	3,151,323	6,709,663
16	Reservoirs, Dams, and Waterways	36,503,597	28,499,090
17	Equipment Costs	15,512,934	29,651,344
18	Roads, Railroads, and Bridges	2,679,316	5,360,063
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	58,245,353	70,550,172
21	Cost per KW of Installed Capacity (line 20 / 5)	1,456.1338	955.3172
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	39,605	68,036
25	Hydraulic Expenses	16,203	10,626
26	Electric Expenses	331,157	1,216,193
27	Misc Hydraulic Power Generation Expenses	568	993
28	Rents	5,090	9,285
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	19,463	173,963
31	Maintenance of Reservoirs, Dams, and Waterways	256,689	162,686
32	Maintenance of Electric Plant	220,079	515,227
33	Maintenance of Misc Hydraulic Plant	76,687	176,542
34	Total Production Expenses (total 23 thru 33)	965,541	2,333,551
35	Expenses per net KWh	0.0169	0.0211

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
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Line No.	Item (a)	FERC Licensed Project No. 803 Plant Name: DE SABLA (b)	FERC Licensed Project No. 2310 Plant Name: DRUM NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1963	1913
4	Year Last Unit was Installed	1963	1928
5	Total installed cap (Gen name plate Rating in MW)	18.45	49.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	19	54
7	Plant Hours Connect to Load	7,690	3,181
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	19	54
10	(b) Under the Most Adverse Oper Conditions	19	54
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	59,656,524	83,913,780
13	Cost of Plant		
14	Land and Land Rights	146,825	1,571,285
15	Structures and Improvements	3,122,920	5,541,698
16	Reservoirs, Dams, and Waterways	41,913,456	39,678,065
17	Equipment Costs	6,170,443	23,339,876
18	Roads, Railroads, and Bridges	2,441,056	1,410,081
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	53,794,700	71,541,005
21	Cost per KW of Installed Capacity (line 20 / 5)	2,915.7019	1,454.0855
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	514	40,807
25	Hydraulic Expenses	26,225	177,263
26	Electric Expenses	710,981	412,909
27	Misc Hydraulic Power Generation Expenses	6,414,625	7,945
28	Rents	37,840	52,689
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	129,091	12,081
31	Maintenance of Reservoirs, Dams, and Waterways	671,745	66,665
32	Maintenance of Electric Plant	742,172	123,476
33	Maintenance of Misc Hydraulic Plant	1,205,012	90,744
34	Total Production Expenses (total 23 thru 33)	9,938,205	984,579
35	Expenses per net KWh	0.1666	0.0117

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Line No.	Item (a)	FERC Licensed Project No. 1988 Plant Name: HAAS (b)	FERC Licensed Project No. 2130 Plant Name: HALSEY (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1958	1916
4	Year Last Unit was Installed	1958	1916
5	Total installed cap (Gen name plate Rating in MW)	135.00	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	144	11
7	Plant Hours Connect to Load	7,610	7,123
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	144	11
10	(b) Under the Most Adverse Oper Conditions	138	11
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	360,886,120	360,886,120
13	Cost of Plant		
14	Land and Land Rights	30,588	30,588
15	Structures and Improvements	11,737,499	11,737,499
16	Reservoirs, Dams, and Waterways	29,603,124	29,603,124
17	Equipment Costs	41,123,297	41,123,297
18	Roads, Railroads, and Bridges	797,929	797,929
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	83,292,437	83,292,437
21	Cost per KW of Installed Capacity (line 20 / 5)	616.9810	6,124.4439
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	12,341	9,502
25	Hydraulic Expenses	43,435	4,155
26	Electric Expenses	556,293	80,343
27	Misc Hydraulic Power Generation Expenses	26,448	1,859
28	Rents	30,946	12,269
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	293,460	60,478
31	Maintenance of Reservoirs, Dams, and Waterways	248,746	286,018
32	Maintenance of Electric Plant	859,834	89,897
33	Maintenance of Misc Hydraulic Plant	1,735,782	174,827
34	Total Production Expenses (total 23 thru 33)	3,807,285	719,348
35	Expenses per net KWh	0.0105	0.0020

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Line No.	Item (a)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 2 (b)	FERC Licensed Project No. 1988 Plant Name: KINGS RIVER (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Underground	Semi-Outdoor
3	Year Originally Constructed	1983	1962
4	Year Last Unit was Installed	1983	1962
5	Total installed cap (Gen name plate Rating in MW)	139.50	48.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	155	52
7	Plant Hours Connect to Load	5,775	7,410
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	155	52
10	(b) Under the Most Adverse Oper Conditions	151	52
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	327,205,316	132,080,338
13	Cost of Plant		
14	Land and Land Rights	584,910	15,682
15	Structures and Improvements	39,045,952	5,271,515
16	Reservoirs, Dams, and Waterways	90,039,658	20,171,097
17	Equipment Costs	52,285,342	13,981,486
18	Roads, Railroads, and Bridges	7,536,660	354,839
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	189,492,522	39,794,619
21	Cost per KW of Installed Capacity (line 20 / 5)	1,358.3693	818.8193
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	5,622	4,862
25	Hydraulic Expenses	0	15,685
26	Electric Expenses	294,966	148,958
27	Misc Hydraulic Power Generation Expenses	1,503,660	5,276
28	Rents	394,577	11,194
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	16,962	68,975
31	Maintenance of Reservoirs, Dams, and Waterways	90,326	93,735
32	Maintenance of Electric Plant	519,602	144,568
33	Maintenance of Misc Hydraulic Plant	313,706	588,886
34	Total Production Expenses (total 23 thru 33)	3,139,421	1,082,139
35	Expenses per net KWh	0.0096	0.0082

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Line No.	Item (a)	FERC Licensed Project No. 233 Plant Name: PIT NO. 3 (b)	FERC Licensed Project No. 233 Plant Name: PIT NO. 4 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1955
4	Year Last Unit was Installed	1925	1955
5	Total installed cap (Gen name plate Rating in MW)	80.19	103.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	70	95
7	Plant Hours Connect to Load	6,570	8,758
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	70	95
10	(b) Under the Most Adverse Oper Conditions	70	95
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	257,432,979	400,071,744
13	Cost of Plant		
14	Land and Land Rights	3,791,145	312,988
15	Structures and Improvements	9,206,074	4,300,149
16	Reservoirs, Dams, and Waterways	68,460,657	41,021,512
17	Equipment Costs	29,942,674	38,028,307
18	Roads, Railroads, and Bridges	7,126,541	3,913,417
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	118,527,091	87,576,373
21	Cost per KW of Installed Capacity (line 20 / 5)	1,478.0782	846.1485
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	47,633	55,627
25	Hydraulic Expenses	18,141	19,732
26	Electric Expenses	611,456	347,785
27	Misc Hydraulic Power Generation Expenses	193,482	208,709
28	Rents	136	136
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	2,452	6,532
31	Maintenance of Reservoirs, Dams, and Waterways	25,981	30,753
32	Maintenance of Electric Plant	781,487	324,107
33	Maintenance of Misc Hydraulic Plant	178,998	22,194
34	Total Production Expenses (total 23 thru 33)	1,859,766	1,015,575
35	Expenses per net KWh	0.0072	0.0025

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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. 2107 Plant Name: POE (b)	FERC Licensed Project No. 1962 Plant Name: ROCK CREEK (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1950
4	Year Last Unit was Installed	1958	1950
5	Total installed cap (Gen name plate Rating in MW)	142.83	125.37
6	Net Peak Demand on Plant-Megawatts (60 minutes)	120	126
7	Plant Hours Connect to Load	7,967	7,119
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	120	119
10	(b) Under the Most Adverse Oper Conditions	120	119
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	447,646,495	322,644,207
13	Cost of Plant		
14	Land and Land Rights	821,303	1,777,666
15	Structures and Improvements	4,046,851	21,460,445
16	Reservoirs, Dams, and Waterways	59,968,899	47,873,280
17	Equipment Costs	38,904,520	106,581,651
18	Roads, Railroads, and Bridges	1,626,548	354,708
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	105,368,121	178,047,750
21	Cost per KW of Installed Capacity (line 20 / 5)	737.7170	1,420.1783
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	5,115	5,115
25	Hydraulic Expenses	17,821	15,149
26	Electric Expenses	160,193	1,305,645
27	Misc Hydraulic Power Generation Expenses	441,670	503,409
28	Rents	9,078	36,660
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	139,354	214,260
31	Maintenance of Reservoirs, Dams, and Waterways	141,098	1,166,484
32	Maintenance of Electric Plant	613,095	360,826
33	Maintenance of Misc Hydraulic Plant	147,657	84,633
34	Total Production Expenses (total 23 thru 33)	1,675,081	3,692,181
35	Expenses per net KWh	0.0037	0.0114

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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. 137 Plant Name: WEST POINT (b)	FERC Licensed Project No. 2310 Plant Name: WISE NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1948	1917
4	Year Last Unit was Installed	1948	1917
5	Total installed cap (Gen name plate Rating in MW)	13.60	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	15	14
7	Plant Hours Connect to Load	7,942	7,939
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	14
10	(b) Under the Most Adverse Oper Conditions	13	14
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	69,020,934	65,589,885
13	Cost of Plant		
14	Land and Land Rights	150,912	823,681
15	Structures and Improvements	1,039,104	4,096,375
16	Reservoirs, Dams, and Waterways	5,959,695	17,299,241
17	Equipment Costs	7,585,844	10,714,439
18	Roads, Railroads, and Bridges	285,168	212,689
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,020,723	33,146,425
21	Cost per KW of Installed Capacity (line 20 / 5)	1,104.4649	2,437.2371
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	2,466	11,686
25	Hydraulic Expenses	8,514	753
26	Electric Expenses	265,700	544,347
27	Misc Hydraulic Power Generation Expenses	25,814	2,283
28	Rents	70	15,089
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	53,419	8,319
31	Maintenance of Reservoirs, Dams, and Waterways	161,253	250,741
32	Maintenance of Electric Plant	243,258	76,288
33	Maintenance of Misc Hydraulic Plant	2,152	170,446
34	Total Production Expenses (total 23 thru 33)	762,646	1,079,952
35	Expenses per net KWh	0.0110	0.0165

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2105 Plant Name: BELDEN (d)	FERC Licensed Project No. 2106 Plant Name: JAMES B. BLACK (e)	FERC Licensed Project No. 619 Plant Name: BUCKS CREEK (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Outdoor	Conventional	2
1969	1965	1928	3
1969	1966	1928	4
117.90	168.66	66.00	5
125	172	65	6
5,882	8,709	8,410	7
			8
125	172	65	9
125	172	53	10
0	0	0	11
235,266,815	542,644,584	128,911,667	12
			13
640,218	568,139	810,543	14
11,727,773	766,934	1,474,672	15
58,173,965	66,249,996	21,114,877	16
63,607,879	18,207,990	22,420,669	17
479,445	2,073,884	3,068,244	18
0	0	0	19
134,629,280	87,866,943	48,889,005	20
1,141.8938	520.9708	740.7425	21
			22
0	0	0	23
109,846	29,023	123,794	24
15,060	24,631	9,739	25
325,229	295,071	152,309	26
23,493	262,179	380,933	27
15,455	11,574	21,222	28
0	0	0	29
39,202	10,544	104,521	30
164,300	25,025	155,089	31
219,749	213,236	79,078	32
146,665	24,451	79,279	33
1,058,999	895,734	1,105,964	34
0.0045	0.0017	0.0086	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 2 (d)	FERC Licensed Project No. 1121 Plant Name: COLEMAN (e)	FERC Licensed Project No. 1962 Plant Name: CRESTA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1958	1979	1949	3
1958	1979	1950	4
117.90	12.15	73.80	5
120	13	70	6
7,976	8,445	7,073	7
			8
120	13	70	9
119	5	72	10
0	0	0	11
360,239,676	45,302,645	187,135,206	12
			13
384,372	183,058	1,364,764	14
11,189,102	1,704,073	5,714,160	15
36,168,942	23,741,590	23,843,112	16
34,736,018	13,332,433	11,848,381	17
17,594	1,870,299	135,388	18
0	0	0	19
82,496,028	40,831,453	42,905,805	20
699.7119	3,360.6134	581.3795	21
			22
0	0	0	23
105,665	816	5,115	24
14,616	915	15,680	25
311,043	408,911	150,542	26
1,557	178,071	268,200	27
14,838	9	20,367	28
0	0	0	29
37,777	126,828	145,717	30
81,701	891,380	910,723	31
197,617	209,817	407,226	32
82,765	1,028,538	62,920	33
847,579	2,845,285	1,986,490	34
0.0024	0.0628	0.0106	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2310 Plant Name: DRUM NO. 2 (d)	FERC Licensed Project No. 2310 Plant Name: DUTCH FLAT (e)	FERC Licensed Project No. 137 Plant Name: ELECTRA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1965	1943	1948	3
1965	1943	1948	4
53.10	22.00	102.50	5
50	22	98	6
8,147	6,876	5,693	7
			8
50	22	98	9
49	23	98	10
0	0	0	11
230,525,842	65,434,392	318,290,353	12
			13
441,826	785,641	735,286	14
1,142,045	2,115,430	2,610,434	15
11,721,651	19,247,540	27,559,897	16
8,187,291	15,746,022	24,856,303	17
479,135	394,378	1,407,837	18
0	0	0	19
21,971,948	38,289,011	57,169,757	20
413.7843	1,740.4096	557.7537	21
			22
0	0	0	23
37,531	17,510	133,967	24
174,879	188,829	27,411	25
276,612	373,186	1,188,342	26
7,308	3,416	87,461	27
48,459	22,609	358	28
0	0	0	29
10,751	7,976	264,892	30
57,047	54,137	501,819	31
65,920	62,417	517,527	32
86,076	57,551	10,747	33
764,583	787,631	2,732,524	34
0.0033	0.0120	0.0086	35

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. 2661 Plant Name: HAT CREEK NO. 1 (d)	FERC Licensed Project No. 2661 Plant Name: HAT CREEK NO. 2 (e)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1921	1921	1920	3
1921	1921	1920	4
10.00	10.00	22.72	5
9	9	25	6
8,377	8,601	0	7
			8
9	9	25	9
4	9	0	10
0	0	0	11
36,812,536	31,284,521	0	12
			13
1,047,218	733,666	6,969	14
2,985,501	759,980	1,651,408	15
28,366,638	2,775,286	3,325,126	16
10,025,561	2,822,191	6,167,177	17
267,475	1,171,981	6,186	18
0	0	0	19
42,692,393	8,263,104	11,156,866	20
4,269.2393	826.3104	491.0592	21
			22
0	0	0	23
0	0	1,430	24
541	541	0	25
236,960	222,193	120,285	26
1,060,857	1,060,857	250,398	27
2,626	2,626	64,673	28
0	0	0	29
6,708	3,781	48,693	30
24,517	45,520	10,878	31
83,446	50,291	48,543	32
12,594	33,359	49,312	33
1,428,249	1,419,168	594,212	34
0.0388	0.0454	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1403 Plant Name: NARROWS (d)	FERC Licensed Project No. 2310 Plant Name: NEWCASTLE (e)	FERC Licensed Project No. 2687 Plant Name: PIT NO.1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1942	1986	1922	3
1942	1986	1922	4
10.20	12.70	69.30	5
12	12	61	6
2,314	3,102	8,614	7
			8
12	12	61	9
12	0	61	10
0	0	0	11
22,728,278	10,786,767	227,075,869	12
			13
274,399	2,066,271	2,307,798	14
1,173,893	6,583,663	2,253,094	15
1,220,149	47,616,591	13,046,575	16
7,129,685	8,338,520	38,723,193	17
506,708	3,056,166	1,448,928	18
0	0	0	19
10,304,834	67,661,211	57,779,588	20
1,010.2778	5,327.6544	833.7603	21
			22
0	0	0	23
275,357	9,866	102,586	24
750	0	17,569	25
60,759	26,667	280,102	26
162,775	1,929	890,136	27
0	12,739	0	28
0	0	0	29
5,163	5,090	2,189	30
12,731	216,058	187,003	31
151,270	114,850	210,328	32
15,945	168,341	50,070	33
684,750	555,540	1,739,983	34
0.0301	0.0515	0.0077	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 233 Plant Name: PIT NO. 5 (d)	FERC Licensed Project No. 2106 Plant Name: PIT NO. 6 (e)	FERC Licensed Project No. 2106 Plant Name: PIT NO. 7 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Outdoor	Outdoor	2
1944	1965	1965	3
1944	1965	1965	4
141.84	79.20	109.80	5
160	80	112	6
0	8,596	8,256	7
			8
160	80	112	9
160	80	112	10
0	0	0	11
612,975,367	267,438,940	357,690,402	12
			13
687,742	387,337	323,678	14
21,149,838	6,941,414	6,856,399	15
46,537,842	36,377,850	31,436,620	16
90,880,556	13,377,803	11,787,529	17
9,456,338	687,395	406,204	18
0	0	0	19
168,712,316	57,771,799	50,810,430	20
1,189.4551	729.4419	462.7544	21
			22
0	0	0	23
0	29,023	29,023	24
23,867	18,777	20,813	25
491,392	239,460	260,382	26
242,382	214,354	231,740	27
136	11,574	11,574	28
0	0	0	29
-1,913,381	3,117	8,835	30
-1,837,724	1,650	67,350	31
996,140	151,601	577,602	32
-142,918	28,067	10,650	33
-2,140,106	697,623	1,217,969	34
-0.0035	0.0026	0.0034	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 137 Plant Name: SALT SPRINGS (d)	FERC Licensed Project No. 2130 Plant Name: STANISLAUS (e)	FERC Licensed Project No. 137 Plant Name: TIGER CREEK (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Outdoor	Conventional	2
1931	1963	1931	3
1953	1963	1931	4
42.03	81.90	52.28	5
44	91	58	6
7,564	7,965	7,644	7
			8
44	91	58	9
34	91	58	10
0	0	0	11
125,695,957	333,256,359	227,420,171	12
			13
221,450	428,932	2,572,625	14
2,486,698	6,477,282	8,123,675	15
33,803,923	36,736,275	54,661,888	16
13,510,239	20,380,012	26,815,105	17
1,528,393	1,142,259	7,729,944	18
0	0	0	19
51,550,703	65,164,760	99,903,237	20
1,226.5216	795.6625	1,910.9265	21
			22
0	0	0	23
6,768	443,972	7,791	24
40,675	99,843	20,754	25
1,220,312	2,159,136	805,139	26
145,550	455,979	57,930	27
191	98,596	220	28
0	0	0	29
188,819	1,323,933	244,804	30
7,890,183	551,243	607,423	31
359,088	523,463	394,602	32
5,848	21,893	7,008	33
9,857,434	5,678,058	2,145,671	34
0.0784	0.0170	0.0094	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1354 Plant Name: A.G. WISHON (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
R of R/Storage			1
Conventional			2
1910			3
1910			4
12.80	0.00	0.00	5
20	0	0	6
6,585	0	0	7
			8
20	0	0	9
12	0	0	10
0	0	0	11
25,652,329	0	0	12
			13
976,875	0	0	14
1,528,365	0	0	15
51,024,316	0	0	16
6,364,363	0	0	17
29,468	0	0	18
0	0	0	19
59,923,387	0	0	20
4,681.5146	0.0000	0.0000	21
			22
0	0	0	23
226,010	0	0	24
0	0	0	25
141,132	0	0	26
1,101,147	0	0	27
4,223	0	0	28
0	0	0	29
37,196	0	0	30
15,931	0	0	31
144,810	0	0	32
56	0	0	33
1,670,505	0	0	34
0.0651	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
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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 PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

Schedule Page: 406   Line No.: 11   Column: b

Schedule Page: 406 Line No.: 11 Column: b

Certain FERC Licensed plants have a zero Line 11 (Average Number of Employees) on pages 406 and 407 due to remote operation and headquarters. Refer to the table below for further details for each plant with a zero in Line 11. Each of these plants is attended by roving or relief operators.

PLANT NAME:	REMOTELY OPERATED (Y/N):	REGIONAL OPERATING CENTER:	NUMER OF OPERATORS:	OPERATIONS HEADQUARTERS:	NUMBER OF OPERATORS:	MAINTENANCE HEADQUARTERS:	NUMBER OF SUPPORT STAFF:
PIT NO. 1	Y	NA	NA	Pit 3 PH Switching Center	8	Burney Service Center	39
PIT NO. 3	Y						
PIT NO. 4	Y						
HAT CREEK NO. 1	N						
HAT CREEK NO. 2	N						
PIT NO. 5	Y			Pit 5 PH Switching Center	7		
PIT NO. 6	Y						
PIT NO. 7	Y						
JAMES B. BLACK	Y						
COLEMAN	N			Manton	4	Manton	7
DE SABLA	N			Camp 1	5	Camp 1	6
BUTT VALLEY	Y			Caribou Switching Center	8	Rogers Flat Service Center	37
CARIBOU NO. 1	Y						
CARIBOU NO. 2	Y						
BELDEN	Y						
ROCK CREEK	Y			Rock Creek Switching Center	11		
BUCKS CREEK	Y						
CRESTA	Y						
POE	Y						
DRUM NO. 1	N			Drum Switching Center	7	Auburn SC Service Center	25
DRUM NO. 2	Y						
DUTCH FLAT	Y			Alta Service Center	3		
NARROWS	Y			Wise Switching Center	11	Alta Service Center	10
HALSEY	Y						
WISE NO. 1	N						
NEWCASTLE	Y						
SALT SPRINGS	N			Tiger Creek Switching Center	10	Tiger Creek Service Center	12
TIGER CREEK	Y						
WEST POINT	Y						
ELECTRA	Y						
STANISLAUS	Y			Angels Camp Service Center	3	Angels Camp Service Center	10
HAAS	Y	Fresno Operating Center	5	Balch Camp	8	Auberry Service Center	21
BALCH NO. 1	Y						
BALCH NO. 2	Y						
KINGS RIVER	Y						
KERCKHOFF NO. 1	Y			Auberry	11		

FOOTNOTE DATA

KERCHKHOFF NO. 2	Y			Service Center			
A. G. WISHON	N						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 2735 Plant Name: HELMS PUMPED STORAGE (b)
1	Type of Plant Construction (Conventional or Outdoor)	Underground
2	Year Originally Constructed	1984
3	Year Last Unit was Installed	1984
4	Total installed cap (Gen name plate Rating in MW)	1,053
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	1,050
6	Plant Hours Connect to Load While Generating	2,811
7	Net Plant Capability (in megawatts)	1,212
8	Average Number of Employees	20
9	Generation, Exclusive of Plant Use - Kwh	784,053,024
10	Energy Used for Pumping	1,212,364,607
11	Net Output for Load (line 9 - line 10) - Kwh	-428,311,583
12	Cost of Plant	
13	Land and Land Rights	751,302
14	Structures and Improvements	185,627,148
15	Reservoirs, Dams, and Waterways	450,931,223
16	Water Wheels, Turbines, and Generators	273,553,164
17	Accessory Electric Equipment	61,165,589
18	Miscellaneous Powerplant Equipment	25,902,828
19	Roads, Railroads, and Bridges	8,781,047
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	1,006,712,301
22	Cost per KW of installed cap (line 21 / 4)	956.0421
23	Production Expenses	
24	Operation Supervision and Engineering	15,098
25	Water for Power	343,813
26	Pumped Storage Expenses	13,239
27	Electric Expenses	1,898,701
28	Misc Pumped Storage Power generation Expenses	2,101,242
29	Rents	44,587
30	Maintenance Supervision and Engineering	1,028
31	Maintenance of Structures	492,977
32	Maintenance of Reservoirs, Dams, and Waterways	523,237
33	Maintenance of Electric Plant	3,139,730
34	Maintenance of Misc Pumped Storage Plant	1,174,188
35	Production Exp Before Pumping Exp (24 thru 34)	9,747,840
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	9,747,840
38	Expenses per KWh (line 37 / 9)	0.0124

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDROELECTRIC GENERATING PLANTS:					
2	Alta FERC No.2310	1902	1.00	1.0	3,433,609	13,634,782
3	Centerville FERC No.803	1904	6.40	6.4		17,463,863
4	Chili Bar FERC No.2155	1965	7.02	7.0	27,228,445	18,075,458
5	Coal Canyon	1907				7,575,676
6	Cow Creek FERC No.606	1907	1.44	1.8	3,745,421	3,182,941
7	Crane Valley FERC No.1354	1919	0.99	0.9	164,934	23,258,096
8	Deer Creek FERC No.2310	1908	5.50	5.7	19,144,298	87,621,177
9	Hamilton Branch	1921	5.39	4.8	4,459,717	8,588,805
10	Inskip FERC No.1121	1979	7.65	8.0		20,395,346
11	Kern Canyon FERC No. 178	1921	9.54	11.5		12,783,346
12	Kilarc FERC No.606	1904	3.00	1.6	8,327,693	4,332,045
13	Lime Saddle	1906	2.00	2.0	3,017,132	17,455,558
14	Merced Falls FERC No.2467	1930				
15	Oak Flat FERC No.2105	1985	1.40	1.3	2,329,025	8,783,381
16	Phoenix FERC No.1061	1940	1.60	2.0	5,653,449	15,380,576
17	Potter Valley FERC No.77	1910	9.46	9.2	13,090,222	49,156,531
18	San Joaquin No. 1-A FERC No.1354	1919	0.42	0.4		32,149,806
19	San Joaquin No. 2 FERC No.1354	1917	2.88	3.2	354,930	33,153,732
20	San Joaquin No. 3 FERC No.1354	1923	4.00	4.2		27,525,753
21	South FERC No.1121	1979	6.75	7.0	25,089,079	16,992,536
22	Spaulding No. 1 FERC No.2310	1928	7.04	7.0	4,491,409	41,924,150
23	Spaulding No. 2 FERC No.2310	1928	3.70	4.4	8,860,840	18,521,493
24	Spaulding No. 3 FERC No.2310	1929	6.61	5.8	-7,041	15,054,898
25	Spring Gap FERC No.2130	1921	6.00	7.0	29,954,655	12,171,407
26	Toadtown FERC No.803	1986	1.80	1.5	3,519,807	7,287,347
27	Tule FERC No.1333	1914	4.50	6.4	-2,521,561	15,026,350
28	Volta No.1 FERC No.1121	1980	8.55	9.0	49,310,273	17,552,924
29	Volta No.2 FERC No.1121	1981	0.95	0.9	5,326,779	3,105,076
30	Wise II FERC No.2310	1986	2.87	3.2	-33,782	13,170,152
31	Miscellaneous Minor					16,701,986
32						
33	Photo Voltaic Generating Plants:					
34	AT&T PARK SOLAR ARRAYS	2007	0.11	0.1	130,251	1,990,928
35	SF SERVICE CENTER SOLAR ARRAY 1 & 2	2007	0.18	0.2	61,799	72,959
36	Vaca Dixon Solar Station	2009	2.00	2.0	4,068,953	10,881,965
37	Five Points - Schindler Solar Station #1	2011	15.00	15.0	28,699,174	54,818,128
38	Westside - Schindler Solar Station #2	2011	15.00	15.0	28,707,717	48,312,358
39	Stroud Solar Station	2011	20.00	20.0	37,339,126	62,321,706
40	Cantua Solar Station	2012	20.00	20.0	42,223,391	56,349,026
41	Giffen Solar Station	2012	10.00	10.0	18,948,350	31,412,761
42	Huron Solar Station	2012	20.00	20.0	41,312,760	61,197,254
43	Gates Solar Station	2013	20.00	20.0	43,311,245	65,649,055
44	West Gates Solar Station	2013	10.00	10.0	21,698,973	77,128,541
45	Guernsey Solar Station	2013	20.00	20.0	43,716,766	35,775,278
46						

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	Fuel Cell:					
2	San Francisco State	2011	1.60	1.6	11,119,388	8,504,503
3	California State University East Bay	2011	1.40	1.4	4,801,495	6,582,640
4						
5	INTERNAL COMBUSTION:					
6	(EMERGENCY STANDBY UNITS)					
7	Downieville Diesel Plant	1966	0.75			95,289
8	Grass Valley Mobile Diesel Generator	1971	0.25			38,497
9	Sierra City Mobile Diesel Generator	1972	0.33			49,054
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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.
						1
13,634,782	473,285		168,542	Water		2
2,728,729	4,578,183		1,535,036	Water		3
2,574,852	244,807		500,828	Water		4
	80,538		166,093	Water		5
2,210,376	599,246		760,391	Water		6
23,493,026	143,070		324,827	Water		7
15,931,123	79,345		800,176	Water		8
1,593,470	329,025		242,458	Water		9
2,666,058	565,747		1,665,751	Water		10
1,339,973	219,723		23,179	Water		11
1,444,015	651,369		995,956	Water		12
6,252,102	7,201,744		2,600,320	Water		13
	-7,276			Water		14
6,273,844	234,414		124,139	Water		15
9,612,860	314,765		520,069	Water		16
5,196,251	2,294,948		651,598	Water		17
76,547,157	87,621		119,918	Water		18
11,511,713	270,693		83,938	Water		19
6,881,438	339,866		97,591	Water		20
2,517,413	610,803		1,295,775	Water		21
5,955,135	509,726		250,474	Water		22
5,005,809	477,656		127,861	Water		23
2,277,594	486,954		173,348	Water		24
2,028,568	360,510		591,597	Water		25
4,048,526	3,679,455		1,149,569	Water		26
3,339,189	125,923		315,448	Water		27
2,052,974	802,146		1,752,044	Water		28
3,268,501	631,006		535,040	Water		29
4,588,903	11,404		338,816	Water		30
				Water		31
						32
						33
17,936,287			37,749	Solar		34
405,327			6,252	Solar		35
5,440,983	30,371		12,108	Solar		36
3,654,542	74,716		97,869	Solar		37
3,220,824	73,474		193,073	Solar		38
3,116,085	79,928		136,135	Solar		39
2,817,451	41,083		360,795	Solar		40
3,141,276	43,481		60,308	Solar		41
3,059,863	59,963		249,295	Solar		42
3,282,453	35,884		69,204	Solar		43
7,712,854	43,254		68,180	Solar		44
1,788,764	190,920		214,138	Solar		45
						46

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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.
						1
5,315,314	257,698		280,948	Natural Gas		2
4,701,886	129,892		166,927	Natural Gas		3
						4
						5
						6
				Diesel		7
				Diesel		8
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Schedule Page: 410 Line No.: 5 Column: a

No federal license required. This power plant was retired on April 1, 2013.

Schedule Page: 410 Line No.: 9 Column: a

No federal license required.

Schedule Page: 410 Line No.: 13 Column: a

No federal license required.

Schedule Page: 410 Line No.: 14 Column: a

This hydroelectric plant was sold to Merced Irrigation District on April 16, 2017.

Schedule Page: 410 Line No.: 31 Column: a

No federal license required.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	DIABLO	GATES #1	500.00	500.00	T	79.23		1
2	DIABLO	MIDWAY #2	500.00	500.00	T	84.07		1
3	DIABLO	MIDWAY #3	500.00	500.00	T	84.67		1
4	DIABLO UNIT #1		500.00	500.00	T	0.54		1
5	DIABLO UNIT #2		500.00	500.00	T	0.57		1
6	GATES	MIDWAY	500.00	500.00	T SSP	63.78		1
7	LOS BANOS	GATES #1	500.00	500.00	T	80.85		1
8	LOS BANOS	MIDWAY #2	500.00	500.00	T	144.82		1
9	MALIN	ROUND MTN #2	500.00	500.00	T OTHERS	46.90		1
10	MIDWAY	WHIRLWIND	500.00	500.00	T	52.77		1
11	MOSS LANDING	LOS BANOS	500.00	500.00	T SSP	51.33		1
12	MOSS LANDING	METCALF	500.00	500.00	T	34.98		1
13	ROUND MTN	TABLE MTN #1	500.00	500.00	T SSP	89.03		1
14	ROUND MTN	TABLE MTN #2	500.00	500.00	T SSP	89.02		1
15	TABLE MTN	TESLA	500.00	500.00	T OTHERS	134.99		1
16	TABLE MTN	VACA	500.00	500.00	T	83.30		1
17	TESLA	LOS BANOS #1	500.00	500.00	T	57.14		1
18	TESLA	METCALF	500.00	500.00	T	35.31		1
19	TESLA	TRACY	500.00	500.00	T SSP	1.13		1
20	TRACY	LOS BANOS	500.00	500.00	T SSP	56.23		1
21	VACA	TESLA	500.00	500.00	T	57.00		1
22	ARCO	MIDWAY	230.00	230.00	T SSP	43.36		1
23	ATLANTIC	GOLD HILL	230.00	230.00	T	11.11		1
24	BAHIA	MORAGA	230.00	230.00	T	26.92		1
25	BAKERSFIELD #1 TAP		230.00	230.00	T SSP	6.67		1
26	BAKERSFIELD #2 TAP		230.00	230.00	T	7.01		1
27	BALCH	MCCALL	230.00	230.00		39.76		1
28	BELDEN TAP		230.00	230.00	SSP	0.02		1
29	BELLOTA	COTTLE	230.00	230.00	T	19.87		1
30	BELLOTA	TESLA #2	230.00	230.00	SSP	37.94		1
31	BELLOTA	WARNERVILLE	230.00	230.00	SSP	22.47		1
32	BELLOTA	WEBER	230.00	230.00	T SSP	14.26		1
33	BIRDS LANDING SW STA	SHILOH	230.00	230.00	SSP	0.11		1
34	BIRDS LANDING SW STA	CONTRA COSTA PP	230.00	230.00	T SSP	10.20		1
35	BIRDS LANDING SW STA	CONTRA COSTA SUB	230.00	230.00	T SSP	9.46		1
36					TOTAL	36,802.57		1,450

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	BIRDS LANDING SW STA	RUSSELL	230.00	230.00	SSP	0.11		1
2	BLACK TAP		230.00	230.00	T	0.51		1
3	BORDEN	GREGG	230.00	230.00	SSP	6.21		1
4	BOTTLE ROCK TAP D.W.R.		230.00	230.00	T	1.07		1
5	BRENTWOOD	KELSO	230.00	230.00	T SSP	16.41		1
6	BRIGHTON	BELLOTA	230.00	230.00	T	42.51		1
7	BUCKS CREEK	ROCK CREEK-CRESTA	230.00	230.00	T SSP	9.39		1
8	BUENA VISTA PUMPING		230.00	230.00	T	1.18		1
9	BUENA VISTA PUMPING		230.00	230.00	T	1.21		1
10	BURNEY FOREST		230.00	230.00	T	0.04		1
11	CALIENTE SW STA	MIDWAY #1	230.00	230.00	T SSP	27.17		1
12	CALIENTE SW STA	MIDWAY #2	230.00	230.00	T	27.16		1
13	CALIFORNIA FLATS SW STA	GATES	230.00	230.00	T SSP	22.57		1
14	CAMANCHE PUMPING		230.00	230.00	T SSP	0.45		1
15	CARBERRY SW STA	ROUND MTN	230.00	230.00	T SSP	12.61		1
16	CARIBOU	TABLE MTN	230.00	230.00	T SSP	54.34		1
17	CASTRO VALLEY	NEWARK	230.00	230.00	T	22.71		1
18	COBURN	LAS AGUILAS SW STA	230.00	230.00	T SSP	63.97		1
19	COLGATE	RIO OSO	230.00	230.00	T	40.89		1
20	CONTRA COSTA	BRENTWOOD	230.00	230.00	T SSP	10.06		1
21	CONTRA COSTA	DELTA SWITCHYARD	230.00	230.00	T	18.46		1
22	CONTRA COSTA	LAS POSITAS	230.00	230.00	T SSP	23.83		1
23	CONTRA COSTA	LONE TREE	230.00	230.00		5.62		1
24	CONTRA COSTA	MORAGA #1	230.00	230.00	T SSP	26.76		1
25	CONTRA COSTA	MORAGA #2	230.00	230.00	T SSP	26.84		1
26	CONTRA COSTA PP	CONTRA COSTA SUB	230.00	230.00	T	1.89		1
27	CORTINA	VACA	230.00	230.00	T	53.29		1
28	COTTLE	MELONES	230.00	230.00	T SSP	25.94		1
29	COTTONWOOD	DELEVAN #1	230.00	230.00	T SSP	71.55		1
30	COTTONWOOD	GLENN	230.00	230.00	T	48.33		1
31	COTTONWOOD	LOGAN CREEK	230.00	230.00	T	59.28		1
32	COTTONWOOD	DELEVAN #2	230.00	230.00	T	71.54		1
33	COVE ROAD TAP		230.00	230.00	SSP	0.11		1
34	COYOTE SW STA	METCALF	230.00	230.00	T	0.88		1
35	CRESTA	RIO OSO	230.00	230.00	T SSP	64.78		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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 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	DELEVAN	VACA #2	230.00	230.00	T	71.07		1
2	DELEVAN	CORTINA	230.00	230.00	T	17.97		1
3	DELEVAN	VACA #3	230.00	230.00	T	71.08		1
4	DELEVAN	VACA #1	230.00	230.00	T	71.04		1
5	DELTA SWITCHING YARD	TESLA	230.00	230.00	T	7.70		1
6	DIABLO	MESA	230.00	230.00	T	40.34		1
7	DIABLO PP STANDBY		230.00	230.00	T	0.46		1
8	DOS AMIGOS PUMPING	PANOCHE	230.00	230.00	T SSP	23.68		1
9	EASTSHORE	SAN MATEO	230.00	230.00	SSP	12.43		1
10	EIGHT MILE ROAD	TESLA	230.00	230.00	T SSP	26.64		1
11	EIGHT MILE ROAD	STAGG	230.00	230.00	T SSP	7.20		1
12	ELECTRA	BELLOTA	230.00	230.00	T SSP	29.23		1
13	FIGARDEN #1 TAP		230.00	230.00	N/A	0.85		1
14	FIGARDEN #2 TAP		230.00	230.00	N/A	0.83		1
15	FULTON	LAKEVILLE-IGNACIO	230.00	230.00		15.84		1
16	FULTON	IGNACIO #1	230.00	230.00	T SSP	40.73		1
17	FULTON	LAKEVILLE	230.00	230.00	T SSP	25.51		1
18	FULTON	LAKEVILLE	230.00	230.00	N/A	1.19		1
19	GATES	MUSTANG SW STA #1	230.00	230.00	T SSP	13.17		1
20	GATES	MUSTANG SW STA #2	230.00	230.00	T SSP	13.18		1
21	GATES	ARCO	230.00	230.00	T	35.18		1
22	GATES	PANOCHE #1	230.00	230.00	T SSP	43.79		1
23	GATES	PANOCHE #2	230.00	230.00	T SSP	43.80		1
24	GATES	MIDWAY	230.00	230.00	T SSP	63.86		1
25	GEYSERS #12	FULTON	230.00	230.00	T SSP	24.09		1
26	GEYSERS #13 TAP		230.00	230.00	T	2.06		1
27	GEYSERS #16 TAP		230.00	230.00	T	1.29		1
28	GEYSERS #17	FULTON	230.00	230.00	T SSP	26.14		1
29	GEYSERS #18 TAP		230.00	230.00	T SSP	0.75		1
30	GEYSERS #20 TAP		230.00	230.00		0.03		1
31	GEYSERS #9	LAKEVILLE	230.00	230.00	SSP	41.71		1
32	GEYSERS #9	LAKEVILLE	230.00	230.00	N/A	1.24		1
33	GLENN	DELEVAN	230.00	230.00	SSP	37.42		1
34	GOLD HILL	EIGHT MILE ROAD	230.00	230.00	T SSP	48.80		1
35	GOLD HILL	LODI STIG	230.00	230.00	T	46.67		1
36					TOTAL	36,802.57		1,450

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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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	GREGG	ASHLAN	230.00	230.00	T SSP	7.00		1
2	GREGG	HERNDON #1	230.00	230.00	T	0.60		1
3	GREGG	HERNDON #2	230.00	230.00	T	0.63		1
4	H	Z #1	230.00	230.00	N/A	6.92		1
5	H	Z #2	230.00	230.00	N/A	6.96		1
6	HAAS	MCCALL	230.00	230.00	T SSP	44.21		1
7	HELM	MCCALL	230.00	230.00	T	30.84		1
8	HELMS	GREGG #1	230.00	230.00	T	60.67		1
9	HELMS	GREGG #2	230.00	230.00	T	60.68		1
10	HERNDON	ASHLAN	230.00	230.00	T SSP	6.39		1
11	HERNDON	KEARNEY	230.00	230.00	T	10.82		1
12	HICKS	METCALF	230.00	230.00	T SSP	9.07		1
13	IGNACIO	SOBRANTE	230.00	230.00	T SSP	42.49		1
14	JEFFERSON	MARTIN	230.00	230.00	SSP	3.31		1
15	JEFFERSON	MARTIN	230.00	230.00	N/A	24.41		1
16	KELSO	TESLA	230.00	230.00	T SSP	7.95		1
17	LAKEVILLE	IGNACIO #2	230.00	230.00	T	14.53		1
18	LAKEVILLE	IGNACIO #1	230.00	230.00	T SSP	15.49		1
19	LAKEVILLE	SOBRANTE #2	230.00	230.00	SSP	47.89		1
20	LAKEVILLE	TULUCAY	230.00	230.00	T SSP	17.22		1
21	LAKEVILLE	TULUCAY	230.00	230.00	T SSP	0.06		1
22	LAMBIE SW STA	BIRDS LANDING SW STA	230.00	230.00	T	7.04		1
23	LAS AGUILAS SW STA	PANOCHE #2	230.00	230.00	SSP	17.44		1
24	LAS AGUILAS SW STA	PANOCHE #1	230.00	230.00	T SSP	17.44		1
25	LAS POSITAS	NEWARK	230.00	230.00	T SSP	20.93		1
26	LOCKEFORD	BELLOTA	230.00	230.00	T	12.32		1
27	LODI STIG	EIGHT MILE ROAD	230.00	230.00	T SSP	2.18		1
28	LOGAN CREEK	DELEVAN	230.00	230.00	T	12.35		1
29	LONE TREE	CAYETANO	230.00	230.00	T SSP	15.40		1
30	LONE TREE	CAYETANO	230.00	230.00	N/A	2.30		1
31	LOS BANOS	DOS AMIGOS	230.00	230.00	T	14.31		1
32	LOS BANOS	PANOCHE #1	230.00	230.00	T OTHERS	37.18		1
33	LOS BANOS	PANOCHE #2	230.00	230.00	T SSP	37.13		1
34	LOS BANOS	SAN LUIS PUMPS #1	230.00	230.00	T	3.43		1
35	LOS BANOS	SAN LUIS PUMPS #2	230.00	230.00	T	3.43		1
36					TOTAL	36,802.57		1,450

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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)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	LOS BANOS	QUINTO SW STA	230.00	230.00	T	12.06		1
2	LOS ESTEROS	METCALF	230.00	230.00	T SSP	63.25		1
3	LOS ESTEROS	METCALF	230.00	230.00	N/A	2.73		1
4	MALACHA TAP		230.00	230.00	T	0.12		1
5	MELONES	WILSON	230.00	230.00	T SSP	61.61		1
6	METCALF	MONTA VISTA #3	230.00	230.00		28.59		1
7	METCALF	MOSS LANDING #1	230.00	230.00	T SSP	35.76		1
8	METCALF	MOSS LANDING #2	230.00	230.00	SSP	35.76		1
9	MIDDLE FORK	GOLD HILL	230.00	230.00	T SSP	44.08		1
10	MIDWAY	KERN #1	230.00	230.00	T SSP	41.75		1
11	MIDWAY	KERN #3	230.00	230.00	T	20.88		1
12	MIDWAY	KERN #4	230.00	230.00	T SSP	20.84		1
13	MIDWAY	WHEELER RIDGE #1	230.00	230.00	T	52.68		1
14	MIDWAY	SUNSET	230.00	230.00	T	0.57		1
15	MIDWAY	WHEELER RIDGE #2	230.00	230.00		52.65		1
16	MONTA VISTA	COYOTE SW STA	230.00	230.00	T	27.83		1
17	MONTA VISTA	HICKS	230.00	230.00	T SSP	13.27		1
18	MONTA VISTA	JEFFERSON #1	230.00	230.00	T SSP	19.72		1
19	MONTA VISTA	JEFFERSON #2	230.00	230.00	SSP	19.73		1
20	MONTA VISTA	SARATOGA	230.00	230.00	T SSP	5.49		1
21	MONTEZUMA SW STA	BIRDS LANDING SW STA	230.00	230.00	SSP OTHERS	0.54		1
22	MORAGA	CASTRO VALLEY	230.00	230.00	T	14.92		1
23	MORRO BAY	DIABLO	230.00	230.00		15.78		1
24	MORRO BAY	CALIFORNIA FLATS SW STA	230.00	230.00	T SSP	46.19		1
25	MORRO BAY	MESA	230.00	230.00	T	35.27		1
26	MORRO BAY	SOLAR SW STA #1	230.00	230.00	T SSP	45.55		1
27	MORRO BAY	SOLAR SW STA #2	230.00	230.00	T SSP	45.56		1
28	MORRO BAY	TEMPLETON	230.00	230.00	T SSP	16.43		1
29	MOSS LANDING	COBURN	230.00	230.00	T SSP SWP	64.03		1
30	MOSS LANDING	LAS AGUILAS SW STA	230.00	230.00	SSP	51.89		1
31	MOSS LANDING		230.00	230.00	T	0.13		1
32	MOSS LANDING TX BK 1	230 SWITCHYARD	230.00	230.00	SWP OTHERS	0.24		1
33	MOSS LANDING TX BK 2	230 SWITCHYARD	230.00	230.00	T SSP	0.16		1
34	MUSTANG SW STA	GREGG	230.00	230.00	T SSP	45.47		1
35	MUSTANG SW STA	MCCALL	230.00	230.00	T SSP	42.11		1
36					TOTAL	36,802.57		1,450

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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	NEWARK	LOS ESTEROS	230.00	230.00	SSP	5.65		1
2	NEWARK	RAVENSWOOD	230.00	230.00	T	8.91		1
3	NEWARK	LOS ESTEROS	230.00	230.00	N/A	2.75		1
4	NEWARK E	F BUS TIE	230.00	230.00		0.22		1
5	NORTH DUBLIN	CAYETANO	230.00	230.00	T	3.02		1
6	NORTH DUBLIN	VINEYARD	230.00	230.00	T	12.46		1
7	NORTH DUBLIN	CAYETANO	230.00	230.00	N/A	2.81		1
8	NORTH DUBLIN	VINEYARD	230.00	230.00	N/A	11.07		1
9	PALERMO	COLGATE	230.00	230.00	T SSP	29.60		1
10	PANOCHE	PANOCHE ENERGY	230.00	230.00	SSP	0.09		1
11	PANOCHE	TRANQUILLITY SW STA #1	230.00	230.00	T SSP	12.14		1
12	PANOCHE	TRANQUILLITY SW STA #2	230.00	230.00	T SSP	12.14		1
13	PARKWAY	MORAGA	230.00	230.00	T	23.64		1
14	PEABODY	BIRDS LANDING SW STA	230.00	230.00	T SSP SWP	19.85		1
15	PIT #1	COTTONWOOD	230.00	230.00	T SSP	59.75		1
16	PIT #3	PIT #1	230.00	230.00	T SSP	22.69		1
17	PIT #3	CARBERRY SW STA	230.00	230.00	T SSP	10.91		1
18	PIT #4 TAP		230.00	230.00	T SSP	7.03		1
19	PIT #5	ROUND MTN #1	230.00	230.00	T OTHERS	13.12		1
20	PIT #5	ROUND MTN #2	230.00	230.00	T SSP	13.11		1
21	PIT #6 JCT	ROUND MTN	230.00	230.00	T SSP	8.15		1
22	PIT #6 TAP		230.00	230.00	T OTHERS	3.43		1
23	PIT #7 TAP		230.00	230.00	T OTHERS	3.59		1
24	PITTSBURG	EASTSHORE	230.00	230.00	T SSP SWP	34.92		1
25	PITTSBURG	SAN MATEO	230.00	230.00	T SSP	47.40		1
26	PITTSBURG	TASSAJARA	230.00	230.00	SSP	17.36		1
27	PITTSBURG	SAN RAMON	230.00	230.00	T SSP SWP	21.66		1
28	PITTSBURG	TESORO	230.00	230.00		11.27		1
29	PITTSBURG	TESLA #1	230.00	230.00	T SSP	31.35		1
30	PITTSBURG	TESLA #2	230.00	230.00	T SSP SWP	31.32		1
31	PITTSBURG	TIDEWATER	230.00	230.00	T	11.27		1
32	POE	RIO OSO	230.00	230.00	T SSP	56.09		1
33	QUINTO SW STA	WESTLEY	230.00	230.00	T	57.55		1
34	RALPH TAP		230.00	230.00	SSP	0.06		1
35	RANCHO SECO	BELLOTA #1	230.00	230.00	T	27.39		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		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	RANCHO SECO	BELLOTA #2	230.00	230.00		27.36		1
2	RAVENSWOOD	SAN MATEO #2	230.00	230.00	SSP	11.88		1
3	RAVENSWOOD	SAN MATEO #1	230.00	230.00	T SSP	11.89		1
4	RIO OSO	ATLANTIC	230.00	230.00	T SSP	17.68		1
5	RIO OSO	BRIGHTON	230.00	230.00	T	27.17		1
6	RIO OSO	GOLD HILL	230.00	230.00	T	28.63		1
7	RIO OSO	LOCKEFORD	230.00	230.00	T	65.13		1
8	ROCK CREEK	POE	230.00	230.00	T SSP SWP	26.98		1
9	ROSSMOOR #1 TAP		230.00	230.00	T	0.69		1
10	ROSSMOOR #2 TAP		230.00	230.00	T	0.66		1
11	ROUND MTN	COTTONWOOD #2	230.00	230.00	T OTHERS	33.67		1
12	ROUND MTN	COTTONWOOD #3	230.00	230.00	T SSP	33.36		1
13	RUSSELL CITY ENERGY	EASTSHORE #1	230.00	230.00	SSP	1.19		1
14	RUSSELL CITY ENERGY	EASTSHORE #2	230.00	230.00	SSP	1.20		1
15	SAN MATEO	MARTIN	230.00	230.00	N/A	13.00		1
16	SAN RAMON	MORAGA	230.00	230.00	T SSP SWP	22.24		1
17	SAN RAMON RESEARCH		230.00	230.00	T SSP	3.27		1
18	SANTA FE GEOTHERMAL		230.00	230.00	T SSP	1.04		1
19	SARATOGA	VASONA	230.00	230.00	T SSP	3.41		1
20	SHILOH II	BIRDS LANDING SW STA	230.00	230.00	SSP	3.56		1
21	SOLAR SW STA	CALIENTE SW STA #1	230.00	230.00	T	8.22		1
22	SOLAR SW STA	CALIENTE SW STA #2	230.00	230.00	T	8.22		1
23	SPI (BURNEY) TAP		230.00	230.00	T	0.05		1
24	STAGG	TESLA	230.00	230.00		23.64		1
25	STOCKDALE #1 TAP		230.00	230.00	T SSP	6.23		1
26	STOCKDALE #2 TAP		230.00	230.00	T	6.14		1
27	TABLE MTN	PALERMO	230.00	230.00	T OTHERS	14.57		1
28	TABLE MTN	RIO OSO	230.00	230.00		50.17		1
29	TASSAJARA	NEWARK	230.00	230.00	T SSP	31.80		1
30	TEMPLETON	GATES	230.00	230.00	T	52.18		1
31	TES TAP		230.00	230.00	T SSP	3.28		1
32	TESLA	NEWARK #2	230.00	230.00	T SSP SWP	40.88		1
33	TESLA	NEWARK #1	230.00	230.00	T	28.19		1
34	TESLA	RAVENSWOOD	230.00	230.00	SSP	37.14		1
35	TESLA	TRACY #1	230.00	230.00	T	5.68		1
36					TOTAL	36,802.57		1,450

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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	TESLA	TRACY #2	230.00	230.00		5.68		1
2	TESLA	WESTLEY	230.00	230.00	T	45.06		1
3	TESORO	SOBRANTE	230.00	230.00		12.32		1
4	TIDEWATER	SOBRANTE	230.00	230.00	T SSP	12.32		1
5	TIGER CREEK	ELECTRA	230.00	230.00	T OTHERS	13.65		1
6	TIGER CREEK	VALLEY SPRINGS	230.00	230.00	T OTHERS	24.22		1
7	TRANQUILLITY SW STA	HELM	230.00	230.00	T SSP	12.68		1
8	TRANQUILLITY SW STA	KEARNEY	230.00	230.00	T SSP	36.90		1
9	TULUCAY	VACA	230.00	230.00	T SSP	23.63		1
10	US WINDPOWER #3 TAP		230.00	230.00	SSP	0.06		1
11	VACA	BAHIA	230.00	230.00	T SSP	33.90		1
12	VACA	PEABODY	230.00	230.00	T SSP	9.69		1
13	VACA	LAKEVILLE #1	230.00	230.00	T SSP	40.93		1
14	VACA	LAMBIE SW STA	230.00	230.00	T	13.95		1
15	VACA	PARKWAY	230.00	230.00	T SSP	27.76		1
16	VACA DIXON	MORAGA #1	230.00	230.00	T	3.08		1
17	VALLEY SPRINGS	BELLOTA	230.00	230.00	T	20.67		1
18	VASONA	METCALF	230.00	230.00	T SSP	13.29		1
19	VINEYARD	NEWARK	230.00	230.00	T	14.36		1
20	VINEYARD	NEWARK	230.00	230.00	N/A	5.94		1
21	WARNERVILLE	WILSON	230.00	230.00		38.40		1
22	WEBER	TESLA	230.00	230.00	T	23.71		1
23	WHEELER RIDGE PUMPING		230.00	230.00	T	0.25		1
24	WHEELER RIDGE PUMPING		230.00	230.00		0.23		1
25	WILSON	GREGG	230.00	230.00	T SSP	41.44		1
26	WILSON	BORDEN	230.00	230.00	T SSP	35.37		1
27	WIND GAP PUMPING PLANT		230.00	230.00	T	1.64		1
28	WIND GAP PUMPING PLANT		230.00	230.00		1.62		1
29	WINDMASTER TAP		230.00	230.00	SSP	0.11		1
30	ZA	1	230.00	230.00	N/A	3.41		1
31	7TH STANDARD	KERN	115.00	115.00	T SSP	6.75		1
32	A	P #1	115.00	115.00	N/A	2.46		1
33	A	H-W #1	115.00	115.00	N/A	4.95		1
34	A	X #1	115.00	115.00	N/A	2.67		1
35	A	Y #1	115.00	115.00	N/A	3.33		1
36					TOTAL	36,802.57		1,450

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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	A	Y #2	115.00	115.00	N/A	2.85		1
2	A	H-W #2	115.00	115.00	N/A	5.06		1
3	ADOBE SW STA	LAMONT	115.00	115.00	T SSP SWP	21.20		1
4	AEC SITE #1 TAP		115.00	115.00	T OTHERS	1.60		1
5	AEC SITE #2 TAP		115.00	115.00	SWP SSP	2.16		1
6	AGNEW TAP		115.00	115.00	SWP SSP	1.32		1
7	AIR PRODUCTS TAP		115.00	115.00	SWP	0.29		1
8	AMERIGAS TAP		115.00	115.00	SWP SSP	0.49		1
9	AMES DISTRIBUTION	AMES	115.00	115.00	SSP	0.10		1
10	APPLE HILL #1 TAP		115.00	115.00	SWP SSP	1.42		1
11	APPLE HILL #2 TAP		115.00	115.00	SWP SSP	1.43		1
12	APPLIED MATERIALS	BRITTON	115.00	115.00	SSP	0.47		1
13	APPLIED MATERIALS	BRITTON	115.00	115.00	N/A	0.74		1
14	ARVIN EDISON TAP		115.00	115.00	SWP	1.06		1
15	ATLANTIC	PLEASANT GROVE #1	115.00	115.00	T SSP SWP	5.33		1
16	ATLANTIC	PLEASANT GROVE #2	115.00	115.00	SWP SSP	5.36		1
17	ATWATER	EL CAPITAN	115.00	115.00	T SSP	7.31		1
18	ATWATER	LIVINGSTON-MERCED	115.00	115.00	SWP SSP	24.26		1
19	ATWATER	CRESSEY	115.00	115.00	SWP SSP	5.91		1
20	BADGER CREEK (PSE) TAP		115.00	115.00	SWP	1.07		1
21	BAIR	BELMONT	115.00	115.00	SSP	3.64		1
22	BALCH	SANGER	115.00	115.00	T SSP	35.62		1
23	BARKER SLOUGH TAP		115.00	115.00	SWP	1.62		1
24	BARTON	AIRWAYS-SANGER	115.00	115.00	T SSP	11.65		1
25	BEAR MTN TAP		115.00	115.00	SWP SSP	1.27		1
26	BEARDSLEY TAP		115.00	115.00	T OTHERS	2.20		1
27	BELL	PLACER	115.00	115.00	T SWP	7.94		1
28	BELLOTA	RIVERBANK-MELONES SW	115.00	115.00	T SSP	44.65		1
29	BELLOTA	RIVERBANK	115.00	115.00	SWP SSP	18.87		1
30	BELRIDGE TAP		115.00	115.00	SWP SSP	6.94		1
31	BIG BEND	CLAYTON #1	115.00		T SWP	0.02		1
32	BOGUE	RIO OSO	115.00	115.00	T SSP	21.24		1
33	BOLLMAN #1 TAP		115.00	115.00	T SSP	2.14		1
34	BOLLMAN #2 TAP		115.00	115.00	T SSP	2.19		1
35	BOLTHOUSE FARMS TAP		115.00	115.00	SWP	0.11		1
36					TOTAL	36,802.57		1,450

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1	BRIDGEVILLE	COTTONWOOD	115.00	115.00	T SSP	86.06		1
2	BRIGHTON	CLAYTON #1	115.00	115.00	T	6.72		1
3	BRIGHTON	CLAYTON #2	115.00	115.00		6.72		1
4	BRIGHTON	DAVIS	115.00	115.00	T SSP	42.73		1
5	BRIGHTON	DAVIS	115.00	115.00	T SSP	17.36		1
6	BRIGHTON	GRAND ISLAND #1	115.00	115.00	T SSP	24.99		1
7	BRIGHTON	GRAND ISLAND #1	115.00	115.00	T SSP	0.14		1
8	BRIGHTON	GRAND ISLAND #2	115.00	115.00	SWP SSP	25.04		1
9	BRIGHTON	GRAND ISLAND #2	115.00	115.00	SWP SSP	0.14		1
10	BRITTON	MONTA VISTA	115.00	115.00	SSP	7.17		1
11	BRUNSWICK #1 TAP		115.00	115.00	T	6.98		1
12	BRUNSWICK #2 TAP		115.00	115.00	T	7.00		1
13	BUELLTON TAP		115.00	115.00	SWP	1.75		1
14	BUTTE	SYCAMORE CREEK	115.00	115.00	SWP SSP	18.17		1
15	BUTTE VALLEY	CARIBOU	115.00	115.00	T SSP	7.42		1
16	C	X #3	115.00	115.00	N/A	3.67		1
17	C	L #1	115.00	115.00	N/A	1.10		1
18	C	X #2	115.00	115.00	N/A	3.38		1
19	CABRILLO	SANTA YNEZ SW STA	115.00	115.00	SWP SSP	14.59		1
20	CAL PEAK	VACA	115.00	115.00	SWP	0.11		1
21	CAL WATER TAP		115.00	115.00	SWP SSP	2.15		1
22	CALIFORNIA AVE	MCCALL	115.00	115.00	T SSP SWP	23.66		1
23	CALLENDER SW STA	MESA	115.00	115.00	T SSP SWP	13.77		1
24	CAMANCHE TAP		115.00	115.00	SWP	6.71		1
25	CAMP EVERS	PAUL SWEET	115.00	115.00	SWP SSP	5.22		1
26	CANTUA TAP		115.00	115.00	SWP SSP	1.83		1
27	CARIBOU	PALERMO	115.00	115.00	T SSP	54.89		1
28	CARQUINEZ #1 TAP		115.00	115.00	T SSP	0.51		1
29	CARQUINEZ #2 TAP		115.00	115.00	SSP	0.52		1
30	CARRIZO PLAINS TAP		115.00	115.00	SSP	0.04		1
31	CASCADE	COTTONWOOD	115.00	115.00	T SSP	19.46		1
32	CAWELO C TAP		115.00	115.00	SWP SSP	1.33		1
33	CERTAINTEED TAP		115.00	115.00	SWP SSP	2.53		1
34	CHARCA	FAMOSO	115.00	115.00	SWP SSP	7.15		1
35	CHCF TAP		115.00	115.00	SWP SSP	3.00		1
36					TOTAL	36,802.57		1,450

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1	CHENEY #1 TAP		115.00	115.00	T SSP SWP	4.10		1
2	CHENEY #2 TAP		115.00	115.00	SWP SSP	1.97		1
3	CHINESE CAMP (ULTRA		115.00	115.00	SWP	2.07		1
4	CHOWCHILLA	KERCKHOFF	115.00	115.00	T SSP	42.52		1
5	CHOWCHILLA #1 TAP		115.00	115.00	SWP	1.25		1
6	CHRISTIE	SOBRANTE	115.00	115.00	T	7.84		1
7	CITY #1 TAP		115.00	115.00	SWP	0.07		1
8	CITY #2 TAP		115.00	115.00	SWP SSP	1.37		1
9	CLAYTON	MEADOW LANE	115.00	115.00	SWP SSP	7.06		1
10	COLES LEVEE TAP		115.00	115.00	SWP	0.22		1
11	COLUMBIA SOLAR 115kV		115.00	115.00	SWP SSP	0.45		1
12	CONTRA COSTA #1		115.00	115.00	T SSP	11.15		1
13	CONTRA COSTA #2		115.00	115.00		1.41		1
14	COOLEY LANDING	PALO ALTO	115.00	115.00	SWP SSP	2.72		1
15	CORCORAN	OLIVE SW STA	115.00	115.00	T SSP	36.83		1
16	CORONA	LAKEVILLE	115.00	115.00	SWP SSP	5.79		1
17	CORTINA	MENDOCINO #1	115.00	115.00	T SWP	60.95		1
18	COTTONWOOD	PANORAMA	115.00	115.00	SWP SSP	2.95		1
19	CRAG VIEW	CASCADE	115.00	115.00	T OTHERS	21.60		1
20	CRAZY HORSE CANYON	SAN BENITO	115.00	115.00	T SSP	8.95		1
21	CRAZY HORSE CANYON	HOLLISTER	115.00	115.00	SSP	17.23		1
22	CRAZY HORSE CANYON	SALINAS-SOLEDAD #1	115.00	115.00	T SSP	35.35		1
23	CRAZY HORSE CANYON	SALINAS-SOLEDAD #2	115.00	115.00	T SSP	35.41		1
24	CYMRIC TAP		115.00	115.00	SWP	0.18		1
25	D	L #1	115.00	115.00	N/A	2.31		1
26	DAIRYLAND	MENDOTA	115.00	115.00	T SSP SWP	28.69		1
27	DANISH CREAMERY TAP		115.00	115.00	SWP	1.20		1
28	DE FRANCESCO TAP		115.00	115.00	SWP SSP	1.02		1
29	DEEPWATER #1 TAP		115.00	115.00	T SSP	2.29		1
30	DEEPWATER #2 TAP		115.00	115.00	SWP SSP	2.45		1
31	DISCOVERY TAP		115.00	115.00	SWP	2.10		1
32	DIVIDE	CABRILLO #2	115.00	115.00	SWP SSP	11.55		1
33	DIVIDE	CABRILLO #1	115.00	115.00	SWP SSP	14.60		1
34	DIXON LANDING	MCKEE	115.00	115.00	SWP SSP	8.30		1
35	DOLAN RD #1 TAP		115.00	115.00	T SSP	0.32		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	DOLAN RD #2 TAP		115.00	115.00	T SSP	0.33		1
2	DONNELLS	CURTIS	115.00	115.00	T SSP	26.81		1
3	DOUBLE C (PSE) TAP		115.00	115.00	SWP	0.06		1
4	DRUM	RIO OSO #1	115.00	115.00	T SSP	44.64		1
5	DRUM	RIO OSO #2	115.00	115.00	T SSP	44.65		1
6	DRUM	SUMMIT #1	115.00	115.00	T SSP	27.36		1
7	DRUM	SUMMIT #2	115.00	115.00	T SSP	28.36		1
8	DRUM	HIGGINS	115.00	115.00	T SSP	47.75		1
9	DRUM PH #2 TAP		115.00	115.00	SWP SSP	0.09		1
10	DUMBARTON	NEWARK	115.00	115.00	T SSP	7.14		1
11	DUTCH FLAT #2 TAP		115.00	115.00	T OTHERS	0.43		1
12	EAGLE ROCK	CORTINA	115.00	115.00	SWP SSP	43.38		1
13	EAGLE ROCK	REDBUD	115.00	115.00	T SSP	23.31		1
14	EAGLE ROCK	FULTON-SILVERADO	115.00	115.00	T SSP	46.94		1
15	EAST GRAND	SAN MATEO	115.00	115.00	T SSP	7.89		1
16	EAST GRAND	SAN MATEO	115.00	115.00	N/A	0.22		1
17	EASTSHORE	DUMBARTON	115.00	115.00	T SSP	12.38		1
18	EASTSHORE	MT EDEN #1	115.00	115.00	T	1.04		1
19	EASTSHORE	MT EDEN #2	115.00	115.00		1.00		1
20	EASTSHORE	CERBERUS	115.00	115.00	SSP	0.48		1
21	EBMUD TAP		115.00	115.00	OTHERS	0.02		1
22	EBMUD TAP		115.00	115.00	N/A	0.94		1
23	EDES #1 TAP		115.00	115.00	SWP SSP	0.05		1
24	EDES #2 TAP		115.00	115.00	T SWP	0.04		1
25	EL CAPITAN	WILSON	115.00	115.00	T SSP	8.12		1
26	EL DORADO	MISSOURI FLAT #1	115.00	115.00	T SSP	14.43		1
27	EL DORADO	MISSOURI FLAT #2	115.00	115.00	SWP SSP	14.41		1
28	EL PATIO	SAN JOSE A	115.00	115.00	T SSP SWP	7.08		1
29	ELLIS TAP		115.00	115.00	SWP	0.17		1
30	EXCELSIOR SW STA	FIVE POINTS PV	115.00	115.00		0.03		1
31	EXCELSIOR SW STA	SCHINDLER #1	115.00	115.00	T SSP	5.24		1
32	EXCELSIOR SW STA	SCHINDLER #2	115.00	115.00	SSP	5.23		1
33	EXCHEQUER	LE GRAND	115.00	115.00	SWP SSP	29.75		1
34	FAIRVIEW	MARTINEZ SW STA	115.00	115.00	SWP	0.10		1
35	FAIRWAY #1 TAP		115.00	115.00	SWP SSP	2.83		1
36					TOTAL	36,802.57		1,450

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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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	FAIRWAY #2 TAP		115.00	115.00		1.52		1
2	FELLOWS	MIDSUN	115.00	115.00	SWP SSP	4.73		1
3	FELLOWS	TAFT	115.00	115.00	T SSP	7.93		1
4	FIBREBOARD STANDARD		115.00	115.00	SWP	0.02		1
5	FIBREBOARD TAP		115.00	115.00	T SSP SWP	1.03		1
6	FLINT TAP		115.00	115.00	T SSP SWP	1.96		1
7	FMC	SAN JOSE B	115.00	115.00	SSP	1.61		1
8	FORBESTOWN TAP		115.00	115.00	SWP SSP	0.22		1
9	FRITO LAY TAP		115.00	115.00	SWP SSP	0.53		1
10	FROGTOWN #1 TAP		115.00	115.00	T	0.12		1
11	FROGTOWN #2 TAP		115.00	115.00		0.11		1
12	FULTON	PUEBLO	115.00	115.00	T SSP	59.90		1
13	FULTON	SANTA ROSA #1	115.00	115.00	T SSP SWP	6.69		1
14	FULTON	SANTA ROSA #2	115.00	115.00	SWP SSP	6.29		1
15	FULTON JCT	VACA	115.00	115.00	T SSP	11.93		1
16	GALLO	LIVINGSTON	115.00	115.00	SWP SSP	4.20		1
17	GALLO	CRESSEY	115.00	115.00	SWP SSP	14.43		1
18	GEYSERS #11	EAGLE ROCK	115.00	115.00	SSP	0.64		1
19	GEYSERS #3	CLOVERDALE	115.00	115.00	T SSP	12.07		1
20	GEYSERS #3	EAGLE ROCK	115.00	115.00	SWP SSP	1.77		1
21	GEYSERS #5	GEYSERS #3	115.00	115.00	SWP	0.49		1
22	GEYSERS #7	EAGLE ROCK	115.00	115.00	T SSP	1.40		1
23	GILL RANCH TAP		115.00	115.00	SWP SSP	9.15		1
24	GILROY ENERGY TAP		115.00	115.00	SWP	0.28		1
25	GISH TAP		115.00	115.00	SWP	0.96		1
26	GOLD HILL	BELLOTA-LOCKEFORD	115.00	115.00	T SSP	87.28		1
27	GOLD HILL	CLARKSVILLE	115.00	115.00	T SSP	5.77		1
28	GOLDEN VALLEY TAP		115.00	115.00	SWP SSP	1.59		1
29	GOLDTREE TAP		115.00	115.00	SWP	2.30		1
30	GRANT	EASTSHORE #1	115.00	115.00	T SSP	4.33		1
31	GRANT	EASTSHORE #2	115.00	115.00	T	4.20		1
32	GREEN VALLEY	CAMP EVERS	115.00	115.00	T SSP	18.59		1
33	GREEN VALLEY	LLAGAS	115.00	115.00	T SSP	24.85		1
34	GREEN VALLEY	PAUL SWEET	115.00	115.00	T SSP	16.03		1
35	GREENLEAF #1 TAP		115.00	115.00	SWP SSP	4.84		1
36					TOTAL	36,802.57		1,450

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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	GRIZZLY TAP (SVP)		115.00	115.00	T SWP	0.16		1
2	GUARDIAN #1 TAP		115.00	115.00	SWP	0.75		1
3	GUARDIAN #2 TAP		115.00	115.00	SWP	0.13		1
4	GWF	KINGSBURG	115.00	115.00	SWP SSP	21.62		1
5	H	P #3	115.00	115.00	T OTHERS	0.17		1
6	H	P #4	115.00	115.00	N/A	5.16		1
7	H	P #1	115.00	115.00	N/A	3.80		1
8	H	Y #1	115.00	115.00	N/A	7.23		1
9	H	P #3	115.00	115.00	N/A	3.59		1
10	HEINZ TAP		115.00		SWP	0.79		1
11	HENRIETTA	LEPRINO SW STA	115.00	115.00	SWP SSP	6.03		1
12	HERNDON	BARTON	115.00	115.00	T SSP	12.68		1
13	HERNDON	BULLARD #1	115.00	115.00	T SSP	11.43		1
14	HERNDON	BULLARD #2	115.00	115.00	SWP SSP	11.42		1
15	HERNDON	MANCHESTER	115.00	115.00	SWP SSP	9.27		1
16	HERNDON	WOODWARD	115.00	115.00	T SSP SWP	12.97		1
17	HIGGINS	BELL	115.00	115.00	T SSP SWP	18.77		1
18	HONCUT TAP		115.00	115.00	T SSP	1.65		1
19	HOWLAND ROAD TAP		115.00	115.00	SWP	0.90		1
20	HUMBOLDT	BRIDGEVILLE	115.00	115.00	T SSP	30.28		1
21	HUMBOLDT	TRINITY	115.00	115.00	T SSP	68.57		1
22	HUMBOLDT BAY	HUMBOLDT #1	115.00	115.00	T SSP	6.31		1
23	IBM BAILEY AVE TAP		115.00	115.00	SWP SSP	2.00		1
24	IBM HARRY RD #1 TAP		115.00	115.00	T	0.58		1
25	IBM HARRY RD #2 TAP		115.00	115.00	SSP	0.58		1
26	IGNACIO	MARE ISLAND #1	115.00	115.00	T SSP SWP	39.48		1
27	IGNACIO	MARE ISLAND #2	115.00	115.00	T OTHERS	43.08		1
28	IGNACIO	SAN RAFAEL #1	115.00	115.00	T SSP	11.54		1
29	IGNACIO	SAN RAFAEL #3	115.00	115.00	SWP OTHERS	8.65		1
30	IMHOFF TAP		115.00	115.00	SWP SSP	1.43		1
31	INGRAM CREEK TAP		115.00	115.00	SWP SSP	0.50		1
32	JAMESON CANYON		115.00	115.00	SWP SSP	0.19		1
33	JARVIS	CRYOGENICS	115.00	115.00	T	0.03		1
34	JESSUP TAP		115.00	115.00	SWP SSP	0.86		1
35	K	D #1	115.00	115.00	N/A	2.44		1
36					TOTAL	36,802.57		1,450

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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	K	D #2	115.00	115.00	N/A	2.57		1
2	KAMM TAP		115.00	115.00	SWP OTHERS	0.52		1
3	KANAKA TAP		115.00	115.00	SWP SSP	2.59		1
4	KANSAS PV	LEPRINO SW STA	115.00	115.00	SSP	0.17		1
5	KERCKHOFF	CLOVIS-SANGER #1	115.00	115.00	T SSP	37.05		1
6	KERCKHOFF	CLOVIS-SANGER #2	115.00	115.00	T SSP SWP	32.05		1
7	KERCKHOFF #1	KERCKHOFF #2	115.00	115.00	T SSP	1.58		1
8	KERN	KERN FRONT	115.00	115.00	SWP SSP	12.52		1
9	KERN	TEVIS-STOCKDALE-LAMON	115.00	115.00	T SSP	21.52		1
10	KERN	LIVE OAK	115.00	115.00	T SSP SWP	10.74		1
11	KERN	MAGUNDEN-WITCO	115.00	115.00	T SSP	19.58		1
12	KERN	ROSEDALE	115.00	115.00	T SSP SWP	1.71		1
13	KERN	TEVIS-STOCKDALE	115.00	115.00	T SSP SWP	19.74		1
14	KERN	TEVIS-STOCKDALE (21KV)	115.00	115.00	T SSP SWP	0.67		1
15	KERN	WESTPARK #1	115.00	115.00	T SSP	3.84		1
16	KERN	WESTPARK #2	115.00	115.00	T	3.83		1
17	KERN OIL	DEXZEL	115.00	115.00	SWP	0.44		1
18	KERN OIL	WITCO	115.00	115.00	T SSP	4.20		1
19	KERNWATER TAP		115.00	115.00	SWP SSP	0.67		1
20	KIFER	FMC	115.00	115.00	T SSP	6.01		1
21	KIFER	FMC	115.00	115.00	N/A	1.11		1
22	KINGS RIVER	SANGER-REEDLEY	115.00	115.00	T SSP SWP	43.35		1
23	KINGSBURG	CORCORAN #1	115.00	115.00	T SSP	27.16		1
24	KINGSBURG	WAUKENA SW STA	115.00	115.00	T	24.94		1
25	KINGSBURG COGEN TAP		115.00	115.00	SWP	1.22		1
26	KM GREEN TAP		115.00	115.00	SSP	0.20		1
27	KYOHO TAP		115.00	115.00	SWP SSP	2.20		1
28	LAKEVILLE	SONOMA #1	115.00	115.00	SWP SSP	6.68		1
29	LAKEVILLE	SONOMA #2	115.00	115.00	SWP SSP	7.18		1
30	LAKEVILLE	SONOMA #1	115.00	115.00	N/A	0.55		1
31	LAKEWOOD	MEADOW LANE-CLAYTON	115.00	115.00	T SSP SWP	9.55		1
32	LAKEWOOD	CLAYTON	115.00	115.00	SSP	5.52		1
33	LAMMERS	KASSON	115.00	115.00	T SSP SWP	8.23		1
34	LAMONT	GRIMMWAY MALAGA	115.00	115.00	SWP SSP	3.55		1
35	LAS PALMAS TAP		115.00	115.00	SWP SSP	0.85		1
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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	LAS PLUMAS TAP		115.00	115.00	SWP SSP	0.48		1
2	LAWRENCE	MONTA VISTA	115.00	115.00	T SSP SWP	9.44		1
3	LAWRENCE LIVERMORE		115.00	115.00	T SSP SWP	9.00		1
4	LAWRENCE LIVERMORE		115.00	115.00	T SWP	9.41		1
5	LE GRAND	DAIRYLAND	115.00	115.00	T SSP SWP	11.40		1
6	LE GRAND	CHOWCHILLA	115.00	115.00	T SSP SWP	10.94		1
7	LEPRINO FOODS	LEPRINO SW STA	115.00	115.00	SWP SSP	6.41		1
8	LEPRINO FOODS (TRACY)		115.00	115.00	SWP	0.02		1
9	LEPRINO SW STA	HENRIETTA PV	115.00	115.00	SSP	0.06		1
10	LEPRINO SW STA	GWF HANFORD SW STA	115.00	115.00	SWP SSP	12.38		1
11	LERDO	KERN OIL-7TH STANDARD	115.00	115.00	T SSP	16.35		1
12	LERDO	FAMOSO	115.00	115.00	T SSP SWP	13.45		1
13	LINCOLN	PLEASANT GROVE	115.00	115.00	SWP SSP	7.38		1
14	LINDE TAP		115.00	115.00	SWP SSP	0.62		1
15	LIVE OAK	KERN OIL	115.00	115.00	T	4.40		1
16	LIVE OAK TAP		115.00	115.00	SWP	3.97		1
17	LLAGAS	GILROY FOODS	115.00	115.00	SWP	1.98		1
18	LLAGAS	HOLLISTER	115.00	115.00	T SSP SWP	21.56		1
19	LOCKHEED #1 TAP		115.00	115.00	SWP SSP	1.72		1
20	LOCKHEED #2 TAP		115.00	115.00	SWP SSP	1.28		1
21	LOS ESTEROS	MONTAGUE	115.00	115.00	SSP	4.64		1
22	LOS ESTEROS	TRIMBLE	115.00	115.00	SSP	3.73		1
23	LOS ESTEROS	AGNEW	115.00	115.00	SWP SSP	1.37		1
24	LOS ESTEROS	NORTECH	115.00	115.00	SSP	1.98		1
25	LOWER LAKE	HOMESTAKE	115.00	115.00	SWP SSP	16.12		1
26	LUCERNE #1 TAP		115.00	115.00	SWP	0.23		1
27	LUCERNE #2 TAP		115.00	115.00	SWP SSP	0.23		1
28	MABURY TAP		115.00	115.00	SWP SSP	2.81		1
29	MADISON	VACA	115.00	115.00	T SSP	22.99		1
30	MALAGA	KRCD	115.00	115.00	SWP	0.99		1
31	MANCHESTER	AIRWAYS-SANGER	115.00	115.00	T SSP	15.07		1
32	MANTECA	VIERRA	115.00	115.00	T SSP SWP	3.98		1
33	MANVILLE TAP		115.00	115.00	SWP SSP	5.54		1
34	MARTIN	DALY CITY #1	115.00	115.00	T	3.93		1
35	MARTIN	DALY CITY #2	115.00	115.00		3.93		1
36					TOTAL	36,802.57		1,450

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	MARTIN	EAST GRAND	115.00	115.00	T SSP SWP	3.96		1
2	MARTIN	MILLBRAE #1	115.00	115.00	T SSP	7.28		1
3	MARTIN	SF AIRPORT	115.00	115.00	T SSP	5.43		1
4	MARTIN	MILLBRAE #1	115.00	115.00	N/A	0.22		1
5	MARTIN	SF AIRPORT	115.00	115.00	N/A	0.23		1
6	MARTINEZ	SHELL OIL #1	115.00	115.00		0.04		1
7	MARTINEZ	SHELL OIL #2	115.00	115.00		0.06		1
8	MARTINEZ	SOBRANTE	115.00	115.00	SSP	16.40		1
9	MCCALL	KINGSBURG #1	115.00	115.00	T SSP SWP	11.65		1
10	MCCALL	KINGSBURG #2	115.00	115.00	SSP	11.57		1
11	MCCALL	MALAGA	115.00	115.00	T SSP SWP	10.96		1
12	MCCALL	REEDLEY	115.00	115.00	T SSP	15.20		1
13	MCCALL	SANGER #1	115.00	115.00	T SSP	9.23		1
14	MCCALL	SANGER #2	115.00	115.00		9.20		1
15	MCCALL	SANGER #3	115.00	115.00	SWP	8.30		1
16	MCCALL	WEST FRESNO #2	115.00	115.00	T SSP	19.61		1
17	MCKEE	PIERCY	115.00	115.00	T	7.75		1
18	MELONES	CURTIS	115.00	115.00	SWP SSP	14.80		1
19	MELONES	RACETRACK	115.00	115.00	SWP SSP	10.20		1
20	MENDOCINO	REDBUD	115.00	115.00		34.83		1
21	MENDOCINO	UKIAH	115.00	115.00	T SSP	9.83		1
22	MENDOTA	NORTH STAR SOLAR	115.00	115.00		0.03		1
23	MESA	DIVIDE #1	115.00	115.00	T SSP	14.71		1
24	MESA	DIVIDE #2	115.00	115.00		14.72		1
25	MESA	SANTA MARIA	115.00	115.00	T SSP SWP	4.36		1
26	MESA	SISQUOC	115.00	115.00	T SSP SWP	17.60		1
27	METCALF	SALINAS #1	115.00	115.00	T	1.94		1
28	METCALF	SALINAS #2 (12KV)	115.00	115.00		6.80		1
29	METCALF	COYOTE PUMPING PLANT	115.00	115.00	SWP SSP	7.86		1
30	METCALF	EDENVALE #1	115.00	115.00	T SSP	5.73		1
31	METCALF	EDENVALE #2	115.00	115.00	T	5.60		1
32	METCALF	EL PATIO #1	115.00	115.00	T SSP	14.39		1
33	METCALF	EL PATIO #2	115.00	115.00		14.40		1
34	METCALF	EVERGREEN #1	115.00	115.00	T	10.63		1
35	METCALF	GREEN VALLEY	115.00	115.00	T SSP	25.28		1
36					TOTAL	36,802.57		1,450

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	METCALF	MORGAN HILL	115.00	115.00	SSP	9.72		1
2	METCALF	HICKS 1 & 2	115.00	115.00	T SSP	6.62		1
3	MIDSET TAP		115.00	115.00	SWP	0.72		1
4	MIDSUN	MIDWAY	115.00	115.00	SWP SSP	18.86		1
5	MIDWAY	RENFRO-TUPMAN	115.00	115.00	T SSP	22.60		1
6	MIDWAY	TUPMAN-RIO	115.00	115.00	T SSP	26.59		1
7	MIDWAY	SHAFTER	115.00	115.00	T SSP SWP	13.63		1
8	MIDWAY	TAFT	115.00	115.00	T SSP	19.33		1
9	MIDWAY	TEMBLOR	115.00	115.00	T SSP	14.53		1
10	MIDWAY	SANTA MARIA	115.00	115.00	T OTHERS	46.72		1
11	MILLBRAE	SAN MATEO #1	115.00	115.00	T SSP	4.71		1
12	MILLER #1 TAP		115.00	115.00	T SSP SWP	21.26		1
13	MILLER #2 TAP		115.00	115.00	SWP SSP	12.32		1
14	MILPITAS	SWIFT	115.00	115.00	T SSP	8.86		1
15	MISSION POWER TAP		115.00	115.00	SWP SSP	1.94		1
16	MISSOURI FLAT	GOLD HILL #1	115.00	115.00	T SSP	19.73		1
17	MISSOURI FLAT	GOLD HILL #2	115.00	115.00	T	19.69		1
18	MOFFETT FIELD TAP		115.00	115.00	SWP	0.16		1
19	MONTA VISTA	WOLFE	115.00	115.00	T SSP	2.72		1
20	MONTA VISTA	WOLFE	115.00	115.00	N/A	1.12		1
21	MONTAGUE	TRIMBLE	115.00	115.00	SSP	2.07		1
22	MONTICELLO PH TAP		115.00	115.00	SWP SSP	0.62		1
23	MORAGA	CLAREMONT #1	115.00	115.00	T OTHERS	5.28		1
24	MORAGA	CLAREMONT #2	115.00	115.00	T OTHERS	5.30		1
25	MORAGA	OAKLAND #1	115.00	115.00	T SSP	5.04		1
26	MORAGA	OAKLAND #2	115.00	115.00		5.04		1
27	MORAGA	OAKLAND #3	115.00	115.00	T SSP SWP	5.05		1
28	MORAGA	OAKLAND #4	115.00	115.00	SWP	5.05		1
29	MORAGA	OAKLAND J	115.00	115.00	SWP	17.67		1
30	MORAGA	SAN LEANDRO #1	115.00	115.00	T SSP	11.14		1
31	MORAGA	SAN LEANDRO #2	115.00	115.00	SWP	11.01		1
32	MORAGA	SAN LEANDRO #3	115.00	115.00	T SSP	11.00		1
33	MORAGA	LAKEWOOD	115.00	115.00	T SSP	15.11		1
34	MORGAN HILL	LLAGAS	115.00	115.00	T SWP	10.84		1
35	MORRO BAY	SAN LUIS OBISPO #1	115.00	115.00	T	16.01		1
36					TOTAL	36,802.57		1,450

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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	MORRO BAY	SAN LUIS OBISPO #2	115.00	115.00	T	16.02		1
2	MOSS LANDING	DEL MONTE #1	115.00	115.00	T SSP	23.35		1
3	MOSS LANDING	DEL MONTE #2	115.00	115.00	T SSP	23.38		1
4	MOSS LANDING	GREEN VALLEY #1	115.00	115.00	T	14.32		1
5	MOSS LANDING	GREEN VALLEY #2	115.00	115.00	SWP	14.46		1
6	MOSS LANDING	SALINAS #1	115.00	115.00	T	12.00		1
7	MOSS LANDING	SALINAS #2	115.00	115.00	SSP	12.11		1
8	MOSS LANDING	CRAZY HORSE CANYON #1	115.00	115.00	T	10.62		1
9	MOSS LANDING	CRAZY HORSE CANYON #2	115.00	115.00		10.61		1
10	MTN VIEW	MONTA VISTA	115.00	115.00		4.80		1
11	NEWARK	AMES #1	115.00	115.00	T SSP	8.30		1
12	NEWARK	AMES #2	115.00	115.00		8.28		1
13	NEWARK	AMES #3	115.00	115.00	T SWP	8.28		1
14	NEWARK	APPLIED MATERIALS	115.00	115.00	T SSP	11.37		1
15	NEWARK	DIXON LANDING	115.00	115.00	SSP	4.69		1
16	NEWARK	FREMONT #1	115.00	115.00	T SSP	3.71		1
17	NEWARK	FREMONT #2	115.00	115.00	SSP	3.75		1
18	NEWARK	JARVIS #1	115.00	115.00	T SSP	14.25		1
19	NEWARK	JARVIS #2	115.00	115.00	T SSP	14.48		1
20	NEWARK	KIFER	115.00	115.00	T SSP	10.61		1
21	NEWARK	LAWRENCE	115.00	115.00	T OTHERS	10.25		1
22	NEWARK	LAWRENCE LAB	115.00	115.00	T	12.21		1
23	NEWARK	MILPITAS #1	115.00	115.00	T SSP	8.48		1
24	NEWARK	MILPITAS #2	115.00	115.00	SWP SSP	10.30		1
25	NEWARK	NUMMI	115.00	115.00	T SSP SWP	4.94		1
26	NEWARK	NORTHERN RECEIVING	115.00	115.00	T SSP	8.76		1
27	NEWARK	NORTHERN RECEIVING	115.00	115.00	T SSP	8.67		1
28	NEWARK	TRIMBLE	115.00	115.00	T SSP	12.36		1
29	NEWARK	AMES DISTRIBUTION	115.00	115.00	SWP SSP	8.25		1
30	NEWARK	APPLIED MATERIALS	115.00	115.00	N/A	0.74		1
31	NORTECH	NORTHERN RECEIVING	115.00	115.00	SSP	2.21		1
32	NORTH TOWER	MARTINEZ JCT #1 (21KV)	115.00	115.00	T	2.61		1
33	NORTHERN RECEIVING	SCOTT #1	115.00	115.00	T SSP	2.08		1
34	NORTHERN RECEIVING	SCOTT #2	115.00	115.00	SSP	1.98		1
35	NOTRE DAME	BUTTE	115.00	115.00	SWP SSP	2.02		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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 On Structures of Another Line (g)	Number Of Circuits (h)
1	OAKHURST TAP		115.00	115.00	SWP SSP	18.16		1
2	OAKLAND C	MARITIME	115.00	115.00	SWP SSP	2.36		1
3	OAKLAND C	TURBINES	115.00	115.00	SWP SSP	0.19		1
4	OAKLAND J	GRANT	115.00	115.00	T SSP	14.81		1
5	OCEANO	CALLENDER SW STA	115.00	115.00	SWP	4.22		1
6	OLEUM	G #1	115.00	115.00	T SSP	11.29		1
7	OLEUM	G #2	115.00	115.00	OTHERS	11.30		1
8	OLEUM	MARTINEZ	115.00	115.00	T SSP SWP	10.50		1
9	OLEUM	NORTH TOWER-CHRISTIE	115.00	115.00	T SSP	8.33		1
10	OLEUM	UNOCAL #1	115.00	115.00		0.01		1
11	OLEUM	UNOCAL #2	115.00	115.00	SWP	0.05		1
12	OLIVE SW STA	SMYRNA	115.00	115.00	T SSP	22.09		1
13	OWENS BROCKWAY TAP		115.00	115.00	SWP SSP	1.09		1
14	OWENS ILLINOIS TAP		115.00	115.00	SWP	0.68		1
15	OXFORD TAP		115.00	115.00	SWP	3.87		1
16	P	X #2	115.00	115.00	T SSP	0.28		1
17	P	X #1	115.00	115.00	N/A	4.01		1
18	P	X #2 (UNDERGROUND)	115.00	115.00	N/A	3.95		1
19	PALERMO	BOGUE	115.00	115.00	T SSP	35.74		1
20	PALERMO	NICOLAUS	115.00	115.00	T SSP	41.18		1
21	PALERMO	PEASE	115.00	115.00	T	26.53		1
22	PALERMO	WYANDOTTE	115.00	115.00	T SSP SWP	5.30		1
23	PANOCHE	CAL PEAK-STARWOOD	115.00	115.00	SWP	0.10		1
24	PANOCHE	MENDOTA	115.00	115.00	SWP SSP	10.08		1
25	PANOCHE	ORO LOMA	115.00	115.00	T SSP SWP	18.96		1
26	PANOCHE	EXCELSIOR SW STA #1	115.00	115.00	T SSP	28.50		1
27	PANOCHE	EXCELSIOR SW STA #2	115.00	115.00	SSP	28.50		1
28	PARADISE	TABLE MTN	115.00	115.00	T SSP	33.73		1
29	PARADISE	BUTTE	115.00	115.00	SSP OTHERS	13.58		1
30	PARAMOUNT FARMS TAP		115.00	115.00	SWP SSP	0.57		1
31	PEASE	RIO OSO	115.00	115.00	T SSP SWP	27.61		1
32	PENNGROVE SUB TAP		115.00	115.00	SWP	0.81		1
33	PEORIA TAP		115.00	115.00	SWP	0.85		1
34	PIERCY	METCALF	115.00	115.00	T	4.72		1
35	PITTSBURG	CLAYTON #1	115.00	115.00	T SSP	16.82		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	PITTSBURG	CLAYTON #3	115.00	115.00	T SSP	8.41		1
2	PITTSBURG	CLAYTON #4	115.00	115.00	T SSP	8.32		1
3	PITTSBURG	COLUMBIA STEEL	115.00	115.00	T SSP	9.23		1
4	PITTSBURG	LOS MEDANOS #1	115.00	115.00	SSP	0.54		1
5	PITTSBURG	LOS MEDANOS #2	115.00	115.00	SSP	0.54		1
6	PITTSBURG	KIRKER-COLUMBIA STEEL	115.00	115.00	SSP	9.26		1
7	PITTSBURG	MARTINEZ #1	115.00	115.00	T SSP	17.22		1
8	PITTSBURG	MARTINEZ #2	115.00	115.00		15.83		1
9	PITTSBURG	LOS MEDANOS #1	115.00	115.00	N/A	0.88		1
10	PITTSBURG	LOS MEDANOS #2	115.00	115.00	N/A	0.89		1
11	PLACER	GOLD HILL #1	115.00	115.00	T SSP	20.67		1
12	PLACER	GOLD HILL #2	115.00	115.00	SSP	20.67		1
13	POINT PINOLE TAP		115.00	115.00	SWP SSP	1.30		1
14	POST OFFICE TAP		115.00	115.00	SWP SSP	0.75		1
15	PSE MCKITTRICK TAP		115.00	115.00	SWP	5.21		1
16	QUEBEC TAP		115.00	115.00	SWP	4.35		1
17	RACETRACK TAP		115.00	115.00	SWP SSP	3.55		1
18	RAINBOW TAP		115.00	115.00	SSP	2.59		1
19	RANCHERS COTTON TAP		115.00	115.00	SWP SSP	2.10		1
20	RAVENSWOOD	AMES #1	115.00	115.00	T	7.07		1
21	RAVENSWOOD	AMES #2	115.00	115.00		7.09		1
22	RAVENSWOOD	BAIR #1	115.00	115.00	T	7.43		1
23	RAVENSWOOD	BAIR #2	115.00	115.00	T SSP	11.29		1
24	RAVENSWOOD	COOLEY LANDING #1	115.00	115.00	T	1.62		1
25	RAVENSWOOD	COOLEY LANDING #2	115.00	115.00		1.62		1
26	RAVENSWOOD	PALO ALTO #1	115.00	115.00	T SSP SWP	4.28		1
27	RAVENSWOOD	PALO ALTO #2	115.00	115.00	SWP SSP	4.26		1
28	RAVENSWOOD	SAN MATEO	115.00	115.00	T	12.04		1
29	RINCON #1 TAP		115.00	115.00	T SSP	0.57		1
30	RINCON #2 TAP		115.00	115.00	SSP	0.55		1
31	RIO BRAVO	KERN OIL	115.00	115.00	SWP SSP	7.28		1
32	RIO BRAVO (FRESNO) TAP		115.00	115.00	SWP OTHERS	0.32		1
33	RIO BRAVO (ROCKLIN) TAP		115.00	115.00	SWP	0.40		1
34	RIO BRAVO TOMATO TAP		115.00	115.00	SWP SSP	0.43		1
35	RIO OSO	LINCOLN	115.00	115.00	SWP SSP	11.02		1
36					TOTAL	36,802.57		1,450

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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	RIO OSO	NICOLAUS	115.00	115.00	T	5.39		1
2	RIO OSO	WEST SACRAMENTO	115.00	115.00	T SSP	43.56		1
3	RIO OSO	WOODLAND #1	115.00	115.00	T SSP	45.25		1
4	RIO OSO	WOODLAND #2	115.00	115.00	T SSP SWP	53.37		1
5	RIPON TAP		115.00	115.00	SWP	4.64		1
6	RIVERBANK JCT SW STA	MANTECA	115.00	115.00	SSP	17.65		1
7	SAFEWAY TAP		115.00	115.00	SWP SSP	0.68		1
8	SALT SPRINGS	TIGER CREEK	115.00	115.00	T SSP	16.48		1
9	SAN BENITO	HOLLISTER	115.00	115.00	SSP	8.31		1
10	SAN FRANCISCO #2		115.00	115.00		3.15		1
11	SAN JOAQUIN COGEN TAP		115.00	115.00	SWP	0.04		1
12	SAN JOSE A	SAN JOSE B	115.00	115.00	SSP	1.15		1
13	SAN JOSE B	STONE-EVERGREEN	115.00	115.00	SWP SSP	8.56		1
14	SAN LEANDRO	OAKLND J #1	115.00	115.00	T SSP	6.70		1
15	SAN LUIS #3 TAP		115.00	115.00	T SSP SWP	16.11		1
16	SAN LUIS #5 TAP		115.00	115.00	SWP SSP	1.88		1
17	SAN LUIS OBISPO	OCEANO	115.00	115.00	T SSP	19.90		1
18	SAN LUIS OBISPO	SANTA MARIA	115.00	115.00	SWP SSP	25.96		1
19	SAN MATEO	BAY MEADOWS #1	115.00	115.00	T	4.30		1
20	SAN MATEO	BAY MEADOWS #2	115.00	115.00	T	4.26		1
21	SAN MATEO	BELMONT	115.00	115.00	T SSP	7.20		1
22	SAN MATEO	MARTIN #3	115.00	115.00	T SSP SWP	11.55		1
23	SAN MATEO	MARTIN #6	115.00	115.00	SSP	11.68		1
24	SAN MATEO	MARTIN #4	115.00	115.00	SWP SSP	11.64		1
25	SAN MATEO	MARTIN #4	115.00	115.00	N/A	0.21		1
26	SAN MATEO	MARTIN #3	115.00	115.00	N/A	0.21		1
27	SAN MATEO	MARTIN #6	115.00	115.00	N/A	0.23		1
28	SAN PABLO #1 TAP		115.00	115.00	SSP	0.44		1
29	SAN PABLO #2 TAP		115.00	115.00	T SSP	0.45		1
30	SANDBAR TAP		115.00	115.00	OTHERS	0.09		1
31	SANGER	MALAGA	115.00	115.00	SWP SSP	8.82		1
32	SANGER	CALIFORNIA AVE	115.00	115.00	SWP SSP	9.33		1
33	SANGER	REEDLEY	115.00	115.00	SWP SSP	20.42		1
34	SANGER COGEN TAP		115.00	115.00	SWP SSP	0.83		1
35	SANTA MARIA	SISQUOC	115.00	115.00	SWP SSP	10.57		1
36					TOTAL	36,802.57		1,450

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1	SANTA MARIA COGEN TAP		115.00	115.00	SWP	0.24		1
2	SANTA PAULA	MILLBRAE	115.00	115.00	SSP	0.09		1
3	SANTA ROSA	CORONA	115.00	115.00	SWP SSP	14.39		1
4	SANTA YNEZ TAP		115.00	115.00	SWP SSP	4.06		1
5	SARGENT SW STA	HOLLISTER	115.00	115.00	SWP OTHERS	1.54		1
6	SCHULTE SW STA	LAMMERS	115.00	115.00	T SSP	0.69		1
7	SCHULTE SW STA	KASSON-MANTECA	115.00	115.00	T SSP SWP	16.56		1
8	SEMITROPIC	CHARCA	115.00	115.00	SWP SSP	6.91		1
9	SEMITROPIC	MIDWAY #1	115.00	115.00	T SSP SWP	14.10		1
10	SEMITROPIC	MIDWAY #2	115.00	115.00	T SSP	20.11		1
11	SERRAMONTE TAP		115.00	115.00	T SSP	2.55		1
12	SF AIRPORT	SAN MATEO	115.00	115.00	T SSP	6.09		1
13	SHAFTER	RIO BRAVO	115.00	115.00	SWP SSP	8.31		1
14	SHARON PRISON TAP		115.00	115.00	SWP SSP	2.57		1
15	SHREDDER TAP		115.00	115.00	T SSP SWP	1.38		1
16	SIERRA #1		115.00	115.00	T	5.47		1
17	SIERRA #2		115.00	115.00		4.86		1
18	SIERRA (PSE) TAP		115.00	115.00	SWP SSP	1.81		1
19	SIERRA PACIFIC IND TAP		115.00	115.00	SWP	0.06		1
20	SILVERADO	FULTON JCT	115.00	115.00	T SWP	26.16		1
21	SISQUOC	GAREY	115.00	115.00	SWP SSP	5.02		1
22	SISQUOC	SANTA YNEZ SW STA	115.00	115.00	SWP SSP	22.12		1
23	SKAGGS ISLAND #1 TAP		115.00	115.00	T	0.59		1
24	SKAGGS ISLAND #2 TAP		115.00	115.00	T	0.60		1
25	SLY CREEK TAP		115.00	115.00	SWP SSP	5.34		1
26	SMYRNA	SEMITROPIC-MIDWAY	115.00	115.00	T SSP	44.65		1
27	SOBRANTE	G #1	115.00	115.00	T SSP SWP	5.34		1
28	SOBRANTE	G #2	115.00	115.00	SSP	5.39		1
29	SOBRANTE	GRIZZLY-CLAREMONT #1	115.00	115.00	T SSP SWP	19.58		1
30	SOBRANTE	MORAGA	115.00	115.00	T SSP SWP	5.68		1
31	SOBRANTE	GRIZZLY-CLAREMONT #2	115.00	115.00	T SSP SWP	19.30		1
32	SOBRANTE	R #1	115.00	115.00	T SSP	5.54		1
33	SOBRANTE	R #2	115.00	115.00		5.53		1
34	SOBRANTE	STANDARD OIL SW STA #2	115.00	115.00	SSP	18.89		1
35	SOBRANTE	STANDARD OIL SW STA #1	115.00	115.00	T SSP	18.89		1
36					TOTAL	36,802.57		1,450

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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)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	SOBRANTE	R #1	115.00	115.00	N/A	4.16		1
2	SOBRANTE	R #2	115.00	115.00	N/A	4.11		1
3	SONOMA	PUEBLO	115.00	115.00	SWP SSP	18.48		1
4	SPRING GAP TAP		115.00	115.00	T OTHERS	1.64		1
5	STANISLAUS	MANTECA #2	115.00	115.00	T SSP SWP	53.95		1
6	STANISLAUS	MELONES SW	115.00	115.00	T SSP SWP	61.15		1
7	STANISLAUS	MELONES SW	115.00	115.00	T SSP	43.80		1
8	STANISLAUS	NEWARK #1 (12KV)	115.00	115.00	T SSP	15.05		1
9	STANISLAUS	NEWARK #2 (12KV)	115.00	115.00	T OTHERS	18.17		1
10	STELLING	MONTA VISTA	115.00	115.00	T SSP	1.61		1
11	STELLING	WOLFE	115.00	115.00	T SSP	1.46		1
12	STELLING	MONTA VISTA	115.00	115.00	N/A	1.14		1
13	STOCKTON A	LOCKEFORD-BELLOTA #1	115.00	115.00	T SSP	34.77		1
14	STOCKTON A	LOCKEFORD-BELLOTA #2	115.00	115.00	T SSP SWP	34.49		1
15	STONE	EVERGREEN-METCALF	115.00	115.00	SWP SSP	12.86		1
16	STONY POINT TAP		115.00	115.00	SWP SSP	3.08		1
17	SURF TAP		115.00	115.00	SWP SSP	11.38		1
18	SWIFT	METCALF	115.00	115.00	T	8.93		1
19	SYCAMORE CREEK	NOTRE DAME-TABLE MTN	115.00	115.00	SWP SSP	20.33		1
20	TABLE MTN	BUTTE #1	115.00	115.00	T SSP SWP	19.54		1
21	TABLE MTN	BUTTE #2	115.00	115.00	T SSP	15.82		1
22	TAFT	CHALK CLIFF	115.00	115.00	SWP SSP	7.18		1
23	TEICHERT TAP		115.00	115.00	SWP SSP	2.11		1
24	TEMBLOR	KERNRIDGE	115.00	115.00	SWP SSP	4.78		1
25	TEMBLOR	SAN LUIS OBISPO	115.00	115.00	T SSP SWP	57.79		1
26	TESLA	SCHULTE SW STA #2	115.00	115.00	T SSP	7.34		1
27	TESLA	SCHULTE SW STA #1	115.00	115.00	T SSP	7.39		1
28	TESLA	SALADO #1	115.00	115.00	T SSP	32.07		1
29	TESLA	SALADO-MANTECA	115.00	115.00	T SSP	53.96		1
30	TESLA	STOCKTON COGEN JCT	115.00	115.00	T SSP SWP	44.47		1
31	TESLA	TRACY	115.00	115.00	T SSP SWP	25.23		1
32	THERMAL ENERGY TAP		115.00	115.00	SWP SSP	0.74		1
33	TRIMBLE	SAN JOSE B	115.00	115.00	SSP	2.53		1
34	TRIMBLE	SAN JOSE B	115.00	115.00	N/A	1.11		1
35	TRINITY	COTTONWOOD	115.00	115.00	T SSP	45.97		1
36					TOTAL	36,802.57		1,450

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1	TULLOCH TAP		115.00	115.00	SWP OTHERS	0.31		1
2	TUPMAN-NORCO TAP		115.00	115.00	SWP SSP	6.67		1
3	UC DAVIS #1 TAP		115.00	115.00	SWP SSP	1.64		1
4	UC DAVIS #2 TAP		115.00	115.00	SWP SSP	1.61		1
5	UKIAH	HOPLAND-CLOVERDALE	115.00	115.00	SWP SSP	31.17		1
6	ULTRAPOWER (OGLE) TAP		115.00	115.00	SWP SSP	2.45		1
7	UNION OIL TAP		115.00	115.00	SWP SSP	0.50		1
8	UNITED COGEN INC TAP		115.00	115.00	SWP SSP	0.68		1
9	UNIVERSITY COGEN TAP		115.00	115.00	SWP	0.22		1
10	VACA	SUISUN	115.00	115.00	T SSP SWP	23.06		1
11	VACA	SUISUN-JAMESON	115.00	115.00	T SSP SWP	25.46		1
12	VACA	VACAVILLE-CORDELIA	115.00	115.00	T SWP	22.04		1
13	VACA	VACAVILLE-JAMESON-NOR	115.00	115.00	T SSP	36.18		1
14	VALLEY CHILDRENS		115.00	115.00		0.03		1
15	VALLEY VIEW #1 TAP		115.00	115.00	SSP	0.96		1
16	VALLEY VIEW #2 TAP		115.00	115.00	SSP	0.97		1
17	VEDDER TAP		115.00	115.00	SWP SSP	11.09		1
18	VIERRA	TRACY-KASSON	115.00	115.00	T SSP SWP	10.49		1
19	WASCO PRISON TAP		115.00	115.00	SWP	0.54		1
20	WAUKENA SW STA	CORCORAN	115.00	115.00		2.37		1
21	WEST FRESNO	CALIFORNIA AVE	115.00	115.00	T SWP	4.90		1
22	WEST SACRAMENTO	BRIGHTON	115.00	115.00	T SSP	13.97		1
23	WEST SACRAMENTO	DAVIS	115.00	115.00	SWP SSP	12.14		1
24	WESTLANDS #1 RA		115.00	115.00	SWP SSP	1.05		1
25	WESTLANDS #18 RA TAP		115.00	115.00	SWP	3.52		1
26	WESTPARK	MAGUNDEN	115.00	115.00	T SSP SWP	12.29		1
27	WHEELER RIDGE	ADOBE SW STA	115.00	115.00	SWP SSP	1.34		1
28	WHISMAN	MONTA VISTA	115.00	115.00	T	5.97		1
29	WHISMAN	MTN VIEW	115.00	115.00	T SWP	3.54		1
30	WILSON	DAIRYLAND (12KV)	115.00	115.00	SWP	11.37		1
31	WILSON	ATWATER #2	115.00	115.00	T SSP	15.41		1
32	WILSON	LE GRAND	115.00	115.00	T SSP	14.04		1
33	WILSON	MERCED #1	115.00	115.00	T SSP SWP	5.58		1
34	WILSON	MERCED #2	115.00	115.00	T SSP SWP	6.20		1
35	WILSON	ORO LOMA	115.00	115.00	T SSP SWP	43.56		1
36					TOTAL	36,802.57		1,450

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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	WITCO (REFINERY) TAP		115.00	115.00	SWP	0.03		1
2	WOODLAND	DAVIS	115.00	115.00	SWP SSP	11.71		1
3	WOODLAND BIOMASS TAP		115.00	115.00	SWP	0.87		1
4	WOODLEAF	PALERMO	115.00	115.00	T SSP	19.62		1
5	WOODWARD	SHEPHERD	115.00	115.00	SWP SSP	4.84		1
6	X	Y #1	115.00	115.00	N/A	0.57		1
7	ZAMORA TAP		115.00	115.00	SWP SSP	1.92		1
8	ZANKER #1 TAP		115.00	115.00	SWP SSP	0.60		1
9	ZANKER #2 TAP		115.00	115.00	SWP SSP	0.72		1
10	AERA ENERGY TAP		70.00	60.00	SWP SSP	0.35		1
11	ANTELOPE TAP		70.00	70.00	SWP SSP	4.33		1
12	ARBURUA TAP		70.00	70.00	SWP	3.57		1
13	ARCO	CARNERAS	70.00	70.00	SWP SSP	17.97		1
14	ARCO	CHOLAME	70.00	70.00	SWP SSP	26.74		1
15	ARCO	POLONIO PASS PP	70.00	70.00	SWP SSP	21.27		1
16	ARCO	TULARE LAKE	70.00	70.00	SWP SSP	16.11		1
17	ARCO	TWISSELMAN	70.00	70.00	SWP SSP	6.52		1
18	ARMSTRONG TAP		70.00	70.00	SWP	0.44		1
19	ATASCADERO	CAYUCOS	70.00	70.00	SWP SSP	11.80		1
20	ATASCADERO	SAN LUIS OBISPO	70.00	70.00	T SSP	15.47		1
21	AUBERRY TAP		70.00	70.00	SWP SSP	2.27		1
22	AVENAL TAP		70.00	70.00	SWP SSP	5.40		1
23	BADGER HILL TAP		70.00	70.00	SWP	1.56		1
24	BERRENDA A TAP		70.00	70.00	SWP	2.25		1
25	BERRENDA C TAP		70.00	70.00	SWP	1.87		1
26	BIOLA	GLASS-MADERA	70.00	70.00	SWP SSP	18.84		1
27	BONITA TAP		70.00	70.00	SWP SSP	3.04		1
28	BORDEN	COPPERMINE	70.00	70.00	SWP SSP	19.95		1
29	BORDEN	GLASS	70.00	70.00	SWP SSP	6.62		1
30	BORDEN	MADERA #2	70.00	70.00	SWP SSP	5.81		1
31	BORDEN	MADERA #1	70.00	70.00	SWP SSP	4.91		1
32	BORDEN	GLASS; XLPE; 70 KV	70.00	70.00	N/A	0.39		1
33	BOSWELL TAP		70.00	70.00	SWP	1.39		1
34	BRICEBURG		70.00	70.00	SWP SSP	7.78		1
35	CADET TAP		70.00	70.00	SWP	0.12		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	CALIFORNIA AVE	KEARNEY	70.00	70.00	SWP	3.20		1
2	CAMDEN	KINGSBURG	70.00	70.00	SWP SSP	14.91		1
3	CANANDAIGUA WINERY		70.00	70.00	SWP	0.29		1
4	CARNATION TAP		70.00	70.00	SWP SSP	0.61		1
5	CARNERAS	TAFT	70.00	70.00	SWP SSP	34.92		1
6	CARUTHERS	LEMOORE NAS-CAMDEN	70.00	70.00	SWP SSP	25.17		1
7	CASTAIC TAP		70.00	70.00	SWP	0.02		1
8	CAWELO B TAP		70.00	70.00	SWP	0.40		1
9	CAYUCOS	CAMBRIA	70.00	70.00	SWP SSP	17.73		1
10	CELERON TAP		70.00	70.00	SWP	0.04		1
11	CHEVRON (LOST HILLS)		70.00	70.00	SWP	14.75		1
12	CHEVRON PIPELINE		70.00	70.00	SWP	1.17		1
13	COALINGA #1	COALINGA #2	70.00	70.00	SWP SSP	8.61		1
14	COALINGA #1	SAN MIGUEL	70.00	70.00	T SSP SWP	38.01		1
15	COALINGA COGEN TAP		70.00	70.00	SWP SSP	4.91		1
16	COPPERMINE	TIVY VALLEY	70.00	70.00	SWP SSP	24.01		1
17	COPUS	OLD RIVER	70.00	70.00	SWP SSP	19.61		1
18	CORCORAN	ANGIOLA	70.00	70.00	SWP SSP	8.96		1
19	CORCORAN	GUERNSEY	70.00	70.00	SWP SSP	13.57		1
20	CRESCENT SW STA	SCULPIN PV	70.00		SSP	0.04		1
21	CRESCENT SW STA	SCHINDLER	70.00	70.00	SWP SSP	10.80		1
22	CRESCENT SW STA	STROUD	70.00	70.00	SWP SSP	3.61		1
23	DERRICK TAP		70.00	70.00	SWP	0.85		1
24	DINOSAUR POINT TAP		70.00	70.00	SWP SSP	2.00		1
25	DINUBA	OROSI	70.00	70.00	SWP SSP	9.83		1
26	DINUBA ENERGY TAP		70.00	70.00	SWP	3.16		1
27	DIVIDE	VANDENBERG #1	70.00	70.00	SWP OTHERS	6.64		1
28	DIVIDE	VANDENBERG #2	70.00	70.00	SWP OTHERS	6.57		1
29	DIVIDE	ZACA-LOMPOC (12KV)	70.00	70.00	SWP	10.55		1
30	DUNLAP TAP		70.00	70.00	SWP SSP	16.21		1
31	EISEN TAP		70.00	70.00	SWP	1.86		1
32	EL PECO TAP		70.00	70.00	SWP OTHERS	3.02		1
33	EMIDIO TAP		70.00	70.00	SWP	3.07		1
34	EXCHEQUER	MARIPOSA	70.00	70.00	T SSP SWP	19.30		1
35	EXCHEQUER	YOSEMITE	70.00	70.00	T SSP	34.91		1
36					TOTAL	36,802.57		1,450

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1	FIVE POINTS SW	WHITNEY POINT PV	70.00	70.00	SSP	0.06		1
2	FIVE POINTS SW STA	HURON-GATES	70.00	70.00	T SSP SWP	19.78		1
3	FRESNO COGEN (AGRICO)		70.00	70.00	SWP	3.17		1
4	FRIANT	COPPERMINE	70.00	70.00	SWP	8.30		1
5	FRUITVALE TAP		70.00	70.00	T SWP	0.12		1
6	GARDNER TAP		70.00	70.00	SWP	3.77		1
7	GATES	JAYNE SW STA	70.00	70.00	SWP SSP	0.68		1
8	GATES	COALINGA #2	70.00	70.00	SWP SSP	17.26		1
9	GATES	HURON	70.00	70.00	T SSP SWP	4.50		1
10	GATES	TULARE LAKE	70.00	70.00	SWP SSP	18.34		1
11	GIFFEN TAP		70.00	70.00	SWP SSP	4.95		1
12	GRAPEVINE TAP		70.00	70.00	SWP	0.14		1
13	GUERNSEY	HENRIETTA	70.00	70.00	SWP SSP	18.44		1
14	GWF	HENRIETTA	70.00	70.00	SWP OTHERS	0.12		1
15	GWF HANFORD COGEN		70.00	70.00	SWP OTHERS	0.32		1
16	HAAS	WOODCHUCK	70.00	70.00	SWP SSP	6.79		1
17	HARDWICK TAP		70.00	70.00	SWP	2.74		1
18	HELM	KERMAN	70.00	70.00	SWP SSP	13.25		1
19	HELM	CRESCENT SW STA	70.00	70.00	SWP SSP	4.92		1
20	HELM	STROUD	70.00	70.00	SWP	7.43		1
21	HENRIETTA	LEMOORE	70.00	70.00	SWP SSP	9.37		1
22	HENRIETTA	LEMOORE NAS	70.00	70.00	SWP SSP	1.69		1
23	HENRIETTA	KENT SW STA	70.00	70.00	SWP SSP	1.47		1
24	HERDLYN	TRACY	70.00	70.00	SWP	2.06		1
25	JAYNE SW STA	COALINGA	70.00	70.00	SWP SSP	11.81		1
26	KEARNEY	BIOLA	70.00	70.00	SWP SSP	19.13		1
27	KEARNEY	BOWLES	70.00	70.00	SWP SSP	9.29		1
28	KEARNEY	CARUTHERS	70.00	70.00	SWP	12.05		1
29	KEARNEY	KERMAN	70.00	70.00	SWP SSP	10.98		1
30	KEARNEY ALTERNATE TIE		70.00	70.00	T SWP	0.30		1
31	KEARNEY TIE		70.00	70.00	T SWP	0.15		1
32	KELLEY TAP		70.00	70.00	SWP	2.79		1
33	KENT SW STA	TULARE LAKE	70.00	70.00	T SSP SWP	15.93		1
34	KERN	FRUITVALE	70.00	70.00	T SWP	0.16		1
35	KERN	KERN OIL-FAMOSO	70.00	70.00	T SSP SWP	24.69		1
36					TOTAL	36,802.57		1,450

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1	KERN	MAGUNDEN	70.00	70.00	T SSP SWP	20.61		1
2	KERN	OLD RIVER #1	70.00	70.00	T SSP	11.94		1
3	KERN	OLD RIVER #2	70.00	70.00	SWP SSP	23.07		1
4	KERN CANYON	MAGUNDEN-WEEDPATCH	70.00	70.00	T SSP SWP	20.65		1
5	KETTLEMAN HILLS TAP		70.00	70.00	SWP SSP	1.02		1
6	KINGSBURG	LEMOORE	70.00	70.00	T SSP	27.49		1
7	LAS PERILLAS TAP		70.00	70.00	SWP	0.39		1
8	LEPRINO TAP		70.00	70.00	SWP	0.47		1
9	LIGHTNER TAP		70.00	70.00	SWP	3.06		1
10	LIVINGSTON	LIVINGSTON JCT	70.00	70.00	SWP SSP	23.36		1
11	LOS BANOS	MERCY SPRINGS SW STA	70.00	70.00	T SSP SWP	14.73		1
12	LOS BANOS	LIVINGSTON JCT-CANAL	70.00	70.00	SWP SSP	14.29		1
13	LOS BANOS	O'NEILL PGP	70.00	70.00	T SSP	3.88		1
14	LOS BANOS	PACHECO	70.00	70.00	T SSP	20.78		1
15	LOST HILLS TAP		70.00	70.00	SWP SSP	2.89		1
16	MARICOPA	COPUS	70.00	70.00	SWP SSP	7.86		1
17	MCFARLAND TAP		70.00	70.00	SWP	5.99		1
18	MCSWAIN TAP		70.00	70.00	SWP	1.37		1
19	MENDOTA	SAN JOAQUIN-HELM	70.00	70.00	SWP SSP	26.96		1
20	MENDOTA BIOMASS TAP		70.00	70.00	SWP SSP	3.84		1
21	MERCED	MERCED FALLS	70.00	70.00	T SSP	20.93		1
22	MERCED #1		70.00	70.00	T SSP SWP	39.88		1
23	MERCED FALLS	EXCHEQUER	70.00	70.00	T SSP	6.29		1
24	MERCY SPRINGS SW STA	CANAL-ORO LOMA	70.00	70.00	SWP SSP	23.32		1
25	MOCO TAP		70.00	70.00	SWP	1.64		1
26	MUSTANG TAP		70.00	70.00	SWP	0.71		1
27	OIL CITY TAP		70.00	70.00	SWP	0.05		1
28	ORO LOMA	CANAL #1	70.00	70.00	T SSP SWP	24.56		1
29	ORO LOMA	MENDOTA	70.00	70.00	SWP SSP	29.58		1
30	PASO ROBLES	TEMPLETON	70.00	70.00	SWP SSP	4.90		1
31	PENN ZIER TAP		70.00	70.00	SWP	4.99		1
32	PENTLAND TAP		70.00	70.00	SWP	0.55		1
33	REEDLEY	DINUBA #1	70.00	70.00	SWP SSP	7.70		1
34	REEDLEY	OROSI	70.00	70.00	SWP SSP	10.89		1
35	RESERVE OIL TAP		70.00	70.00	SWP	0.58		1
36					TOTAL	36,802.57		1,450

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1	RIO BRAVO HYDRO		70.00	70.00	SWP	0.24		1
2	RIVER ROCK TAP		70.00	70.00	SWP	1.21		1
3	ROSE TAP		70.00	70.00	SWP	0.31		1
4	SAN BERNARD	TEJON	70.00	70.00	SWP SSP	6.96		1
5	SAN LUIS OBISPO	CAYUCOS	70.00	70.00	SWP SSP	23.39		1
6	SAN LUIS OBISPO	SANTA MARIA *	70.00	70.00	SWP SSP	13.33		1
7	SAN MIGUEL	PASO ROBLES	70.00	70.00	SWP	9.92		1
8	SANGER	CALIFORNIA AVE #1	70.00	70.00	SWP SSP	9.23		1
9	SCHINDLER	COALINGA #2	70.00	70.00	SWP SSP	17.26		1
10	SCHINDLER	FIVE POINTS SW STA	70.00	70.00	SWP SSP	1.70		1
11	SEMITROPIC	WASCO	70.00	70.00	T SSP SWP	6.32		1
12	SOLAR TANNEHILL TAP		70.00	70.00	SWP	2.65		1
13	STONE CORRAL TAP		70.00	70.00	SWP SSP	7.56		1
14	SYCAMORE TAP		70.00	70.00	SWP SSP	2.04		1
15	TAFT	CUYAMA #1	70.00	70.00	SWP SSP	19.25		1
16	TAFT	CUYAMA #2	70.00	70.00	SWP SSP	18.75		1
17	TAFT	ELK HILLS	70.00	70.00	SWP SSP	12.39		1
18	TAFT	MARICOPA	70.00	70.00	T SSP	5.98		1
19	TECUYA TAP		70.00	70.00	SWP SSP	1.91		1
20	TEJON	LEBEC	70.00	70.00	SWP SSP	13.00		1
21	TEMPLETON	ATASCADERO	70.00	70.00	SWP SSP	8.82		1
22	TEXACO (LOST HILLS) TAP		70.00	70.00	SWP	0.01		1
23	TEXACO BASIC SCHOOL		70.00	70.00	SWP	0.75		1
24	TEXACO BUENA VISTA		70.00	70.00	SWP	0.10		1
25	TIVY VALLEY	REEDLEY	70.00	70.00	SWP	12.30		1
26	TORNADO TAP		70.00	70.00	SWP	0.06		1
27	TULE	SPRINGVILLE	70.00	70.00	SWP SSP	15.24		1
28	WASCO	FAMOSO	70.00	70.00	SWP SSP	7.13		1
29	WEEDPATCH	SAN BERNARD	70.00	70.00	SWP SSP	9.29		1
30	WEEDPATCH	WELLFIELD	70.00	70.00	SWP SSP	5.82		1
31	WESIX TAP		70.00	70.00	SWP	2.51		1
32	WESTLANDS TAP		70.00	70.00	SWP	1.07		1
33	WHEELER RIDGE	LAKEVIEW	70.00	70.00	SWP SSP	7.51		1
34	WHEELER RIDGE	SAN BERNARD	70.00	70.00	SWP SSP	5.88		1
35	WHEELER RIDGE	TEJON	70.00	70.00	T SWP	5.01		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WHEELER RIDGE	WEEDPATCH	70.00	70.00	SWP SSP	22.43		1
2	WISHON	COPPERMINE	70.00	70.00	T SSP SWP	19.99		1
3	WISHON	SAN JOAQUIN #3	70.00	70.00	SWP SSP	7.68		1
4	WRIGHT TAP		70.00	70.00	SWP OTHERS	1.18		1
5	YANKE (NORTH FORK) TAP		70.00	70.00	SWP	0.44		1
6	ALMADEN	LOS GATOS	60.00	60.00	SWP SSP	6.38		1
7	ALMENDRA JCT	NICOLAUS	60.00	60.00	SWP SSP	24.90		1
8	AMFOR TAP		60.00	60.00	SWP	1.08		1
9	ARBUCKLE TAP		60.00	60.00	SWP SSP	0.82		1
10	ARCATA	HUMBOLDT	60.00	60.00	SWP SSP	7.28		1
11	AUBURN TAP		60.00	60.00	SWP SSP	0.75		1
12	BAIR	COOLEY LANDING #1	60.00	60.00	T SSP SWP	5.55		1
13	BAIR	COOLEY LANDING #2	60.00	60.00	SWP	5.60		1
14	BASALT #1 TAP		60.00	60.00	T SWP	1.18		1
15	BEALE AFB (WAPA) #1 TAP		60.00	60.00	SSP	0.11		1
16	BEALE AFB (WAPA) #2 TAP		60.00	60.00	SWP SSP	0.14		1
17	BELLE HAVEN #1 TAP		60.00	60.00	SWP SSP	0.45		1
18	BELLE HAVEN #2 TAP		60.00	60.00	SWP	0.40		1
19	BIXLER TAP		60.00	60.00	SWP	0.55		1
20	BLUE CHIP MILLING TAP		60.00	60.00	SWP	0.42		1
21	BLUE LAKE TAP		60.00	60.00	SWP SSP	3.70		1
22	BRIDGEVILLE	GARBERVILLE	60.00	60.00	SWP SSP	36.16		1
23	BRIONES TAP		60.00	60.00	SWP SSP	7.00		1
24	BUENA VISTA BIOMASS		60.00	60.00	SWP SSP	1.02		1
25	BURNEY TAP		60.00	60.00	SWP SSP	1.09		1
26	BURNS	LONE STAR #1	60.00	60.00	SWP SSP	5.42		1
27	BURNS	LONE STAR #2	60.00	60.00	SWP SSP	6.34		1
28	BUTTE	CHICO #1	60.00	60.00	SWP	0.79		1
29	BUTTE	CHICO #2	60.00	60.00	SWP	0.74		1
30	BUTTE	ESQUON	60.00	60.00	SWP SSP	9.87		1
31	CACHE SLOUGH TAP		60.00	60.00	SWP SSP	6.85		1
32	CALVO TAP		60.00	60.00	SWP	0.54		1
33	CAPE HORN TAP		60.00	60.00	SWP	0.31		1
34	CARBONA #2 TAP		60.00	60.00	SWP	5.64		1
35	CARIBOU	PLUMAS JCT	60.00	60.00	SWP SSP	21.25		1
36					TOTAL	36,802.57		1,450

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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	CARIBOU	WESTWOOD	60.00	60.00	SWP SSP	21.06		1
2	CARIBOU #2		60.00	60.00	SWP SSP	42.12		1
3	CASCADE	BENTON-DESCHUTES	60.00	60.00	SWP SSP	15.98		1
4	CENTERVILLE	TABLE MTN	60.00	60.00	SWP SSP	21.50		1
5	CENTERVILLE	TABLE MTN-OROVILLE	60.00	60.00	T SSP	26.11		1
6	CHICO A	DAYTON RD	60.00		SWP	0.80		1
7	CHRISTIE	FRANKLIN #1	60.00	60.00	SWP SSP	5.01		1
8	CHRISTIE	FRANKLIN #2	60.00	60.00	SWP SSP	5.11		1
9	CHRISTIE	WILLOW PASS	60.00	60.00	T SSP	15.93		1
10	CHUALAR TAP		60.00	60.00	SWP	1.43		1
11	CIC TAP		60.00	60.00	SWP	0.13		1
12	CISCO GROVE TAP		60.00	60.00	SWP	0.34		1
13	CLAY	MARTEL	60.00	60.00	SWP SSP	21.49		1
14	CLEAR LAKE	HOPLAND	60.00	60.00	SWP SSP	11.54		1
15	CLEAR LAKE	KONOCTI	60.00	60.00	SWP SSP	10.95		1
16	CLOVER CREEK TAP		60.00	60.00	SWP	0.02		1
17	COBURN	BASIC ENERGY	60.00	60.00	SWP	3.39		1
18	COBURN	OIL FIELDS #1	60.00	60.00	SWP SSP	29.46		1
19	COBURN	OIL FIELDS #2	60.00	60.00	SWP SSP	31.05		1
20	COGENERATION NATIONAL		60.00	60.00	SWP	0.56		1
21	COLEMAN	COTTONWOOD	60.00	60.00	SWP SSP	8.58		1
22	COLEMAN	RED BLUFF	60.00	60.00	SWP SSP	48.31		1
23	COLEMAN	SOUTH	60.00	60.00	SWP SSP	13.39		1
24	COLEMAN HATCHERY TAP		60.00	60.00	SWP SSP	0.56		1
25	COLGATE	ALLEGHANY	60.00	60.00	SWP SSP	24.55		1
26	COLGATE	CHALLENGE	60.00	60.00	SWP SSP	13.04		1
27	COLGATE	GRASS VALLEY	60.00	60.00	SWP SSP	13.17		1
28	COLGATE	PALERMO	60.00	60.00	SWP SSP	22.65		1
29	COLGATE	SMARTVILLE #1	60.00	60.00	SWP SSP	11.26		1
30	COLGATE	SMARTVILLE #2	60.00	60.00	SWP SSP	11.19		1
31	COLGATE PH	COLGATE SW STA	60.00	60.00	SSP	0.19		1
32	COLLINS PINE TAP		60.00	60.00	SWP	1.00		1
33	COLUSA JCT #1		60.00	60.00	SWP SSP	16.98		1
34	CONTRA COSTA	DU PONT	60.00	60.00	T OTHERS	2.65		1
35	CONTRA COSTA	PITTSBURG	60.00	60.00	T SSP SWP	6.28		1
36					TOTAL	36,802.57		1,450

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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1	CONTRA COSTA	SHELL CHEMICAL#1(21KV)	60.00	60.00		9.55		1
2	CONTRA COSTA	BALFOUR	60.00	60.00	SWP SSP	11.55		1
3	COOLEY LANDING	LOS ALTOS	60.00	60.00	T SSP SWP	14.89		1
4	COOLEY LANDING	LOS ALTOS (I2KV)	60.00	60.00	T SSP SWP	1.41		1
5	COOLEY LANDING	STANFORD	60.00	60.00	SWP SSP	6.04		1
6	COOLEY LANDING	STANFORD	60.00	60.00	N/A	1.59		1
7	CORDELIA #1 TAP		60.00	60.00	SWP SSP	7.69		1
8	CORDELIA #2 TAP		60.00	60.00	SWP SSP	6.87		1
9	CORDELIA INTERIM		60.00	60.00	SWP SSP	0.36		1
10	CORTINA #1		60.00	60.00	SWP SSP	26.29		1
11	CORTINA #2		60.00	60.00	SWP SSP	26.61		1
12	CORTINA #3		60.00	60.00	SWP SSP	24.80		1
13	CORTINA #4		60.00	60.00	SWP SSP	45.28		1
14	COTTONWOOD	BENTON #1	60.00	60.00	T SSP SWP	15.53		1
15	COTTONWOOD	BENTON #2	60.00	60.00	SWP SSP	14.68		1
16	COTTONWOOD	RED BLUFF	60.00	60.00	SWP SSP	16.74		1
17	COTTONWOOD #1		60.00	60.00	T SSP SWP	48.16		1
18	COTTONWOOD #2		60.00	60.00	T SSP SWP	23.63		1
19	CROW CREEK SW STA	FRONTIER SOLAR PV	60.00	60.00	SSP	0.02		1
20	CROW CREEK SW STA	NEWMAN	60.00	60.00	SWP SSP	11.14		1
21	CROWS LANDING TAP		60.00	60.00	SWP	5.28		1
22	CRUSHER TAP		60.00	60.00	SWP SSP	1.95		1
23	CRYSTAL SPRINGS TAP		60.00	60.00	SWP SSP	0.28		1
24	DEAN FOODS TAP		60.00	60.00	SWP	0.51		1
25	DEER CREEK	DRUM	60.00	60.00	SWP SSP	6.24		1
26	DEL MAR	ATLANTIC #1	60.00	60.00	SWP SSP	2.78		1
27	DEL MAR	ATLANTIC #2	60.00	60.00	SWP SSP	4.45		1
28	DEL MAR	ATLANTIC #1	60.00	60.00	N/A	1.18		1
29	DEL MONTE	MONTEREY	60.00	60.00	SWP SSP	2.53		1
30	DEL MONTE	VIEJO	60.00	60.00	SWP SSP	7.92		1
31	DEL MONTE	FORT ORD #1	60.00	60.00	SWP SSP	6.13		1
32	DEL MONTE	FORT ORD #2	60.00	60.00	SWP SSP	5.60		1
33	DELTA	MTN GATE JCT	60.00	60.00	T OTHERS	15.14		1
34	DESABLA	CENTERVILLE	60.00	60.00	T SSP	5.86		1
35	DISTRICT 1001 TAP		60.00	60.00	SWP	1.47		1
36					TOTAL	36,802.57		1,450

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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	DISTRICT 1500 TAP		60.00	60.00	SWP SSP	3.61		1
2	DIXON	VACA #1	60.00	60.00	T SSP SWP	18.35		1
3	DIXON	VACA #2	60.00	60.00	SWP SSP	26.77		1
4	DRUM	GRASS VALLEY-WEIMAR	60.00	60.00	SWP SSP	31.17		1
5	DRUM	SPAULDING	60.00	60.00	SWP SSP	9.36		1
6	DU PONT TAP		60.00	60.00	SWP	0.52		1
7	EAST DUBLIN (BART) TAP		60.00	60.00	SWP	0.04		1
8	EEL RIVER TAP		60.00	60.00	T SSP SWP	2.31		1
9	ELK	GUALALA	60.00	60.00	SWP SSP	29.01		1
10	ELK CREEK TAP		60.00	60.00	SWP SSP	20.44		1
11	ENCINAL TAP		60.00	60.00	SWP SSP	1.43		1
12	ESSEX JCT	ARCATA-FAIRHAVEN	60.00	60.00	T SSP	16.08		1
13	ESSEX JCT	ORICK	60.00	60.00	SWP SSP	31.29		1
14	EUREKA	STA A	60.00	60.00	SWP	0.22		1
15	EVERGREEN	ALMADEN	60.00	60.00	SWP	4.96		1
16	EVERGREEN	MABURY	60.00	60.00	SWP	5.48		1
17	FAIRHAVEN	HUMBOLDT	60.00	60.00	SWP SSP	15.56		1
18	FAIRHAVEN #1		60.00	60.00	SWP	0.41		1
19	FAIRHAVEN POWER CO		60.00	60.00	SWP SSP	0.55		1
20	FITCH MTN #1 TAP		60.00	60.00	SWP	0.87		1
21	FITCH MTN #2 TAP		60.00	60.00	SWP	0.07		1
22	FORKS OF THE BUTTE TAP		60.00	60.00	SWP	0.20		1
23	FORT BRAGG	ELK	60.00	60.00	SWP SSP	24.02		1
24	FORT ROSS	GUALALA	60.00	60.00	SWP SSP	29.76		1
25	FORT SEWARD TAP		60.00	60.00	SWP SSP	7.70		1
26	FRENCH MEADOWS	MIDDLE FORK	60.00	60.00	SWP SSP	13.19		1
27	FRESH EXPRESS TAP		60.00	60.00	SWP	0.56		1
28	FRUITLAND TAP		60.00	60.00	SWP SSP	4.26		1
29	FULTON	WINDSOR	60.00	60.00	SWP SSP	6.59		1
30	FULTON	CALISTOGA	60.00	60.00	SWP SSP	64.60		1
31	FULTON	HOPLAND	60.00	60.00	SWP SSP	41.09		1
32	FULTON	MOLINO-COTATI	60.00	60.00	SWP SSP	20.52		1
33	FULTON	MOLINO-COTATI	60.00	60.00	SWP SSP	0.35		1
34	GARBERVILLE	LAYTONVILLE	60.00	60.00	SWP SSP	39.99		1
35	GARCIA TAP		60.00	60.00	SWP SSP	3.04		1
36					TOTAL	36,802.57		1,450

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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	GLENN #1		60.00	60.00	SWP SSP	33.37		1
2	GLENN #2		60.00	60.00	SWP SSP	34.69		1
3	GLENN #3		60.00	60.00	SWP SSP	28.51		1
4	GLENN #4		60.00	60.00	SWP SSP	12.54		1
5	GLENN #5		60.00	60.00	SWP SSP	7.41		1
6	GOLD HILL #1		60.00	60.00	SWP SSP	27.85		1
7	GONZALES #1 TAP		60.00	60.00	SWP	0.20		1
8	GONZALES #2 TAP		60.00	60.00	SWP SSP	0.30		1
9	GRANITE ROCK TAP		60.00	60.00	SWP	2.39		1
10	GREEN VALLEY	WATSONVILLE	60.00	60.00	SWP SSP	4.74		1
11	GREENLEAF #2 TAP		60.00	60.00	SWP	0.62		1
12	GRONEMEYER TAP		60.00	60.00	SWP	0.83		1
13	GUSTINE #1 TAP		60.00	60.00	SWP SSP	7.56		1
14	GUSTINE #2 TAP		60.00	60.00	SWP	4.44		1
15	GWF #4 TAP		60.00	60.00	T SWP	0.25		1
16	HALSEY	PLACER	60.00	60.00	SWP SSP	4.94		1
17	HAMILTON BRANCH	CHESTER	60.00	60.00	SWP SSP	12.27		1
18	HAMMER	COUNTRY CLUB	60.00	60.00	SWP SSP	8.82		1
19	HARRINGTON TAP		60.00	60.00	SWP	0.53		1
20	HARTLEY	CLEARLAKE	60.00	60.00	SWP SSP	6.66		1
21	HAT CREEK #1	PIT #1	60.00	60.00	T SSP	6.08		1
22	HAT CREEK #1	WESTWOOD	60.00	60.00	SWP SSP	55.87		1
23	HEADGATE TAP		60.00	60.00	SWP SSP	0.97		1
24	HEALDSBURG #1 TAP		60.00	60.00	SWP SSP	0.25		1
25	HEALDSBURG #2 TAP		60.00	60.00	SWP SSP	0.16		1
26	HERDLYN	BALFOUR	60.00	60.00	SWP SSP	20.50		1
27	HILLSDALE JCT	HALF MOON BAY	60.00	60.00	SWP SSP	6.82		1
28	HUMBOLDT	EUREKA	60.00	60.00	SWP SSP	4.70		1
29	HUMBOLDT	MAPLE CREEK	60.00	60.00	SWP SSP	14.13		1
30	HUMBOLDT #1		60.00	60.00	T SSP SWP	11.05		1
31	HUMBOLDT BAY	EUREKA	60.00	60.00	SWP SSP	5.61		1
32	HUMBOLDT BAY	HUMBOLDT #1	60.00	60.00	SWP SSP	8.34		1
33	HUMBOLDT BAY	HUMBOLDT #2	60.00	60.00	SWP SSP	6.45		1
34	HUMBOLDT BAY	RIO DELL JCT	60.00	60.00	SWP SSP	18.40		1
35	IGNACIO	STAFFORD	60.00		SWP SSP	6.13		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	IGNACIO	BOLINAS #1	60.00	60.00	SWP SSP	15.06		1
2	IGNACIO	ALTO	60.00	60.00	SWP SSP	17.79		1
3	IGNACIO	ALTO-SAUSALITO #1	60.00	60.00	T SSP SWP	17.83		1
4	IGNACIO	ALTO-SAUSALITO #2	60.00	60.00	SWP SSP	17.83		1
5	IGNACIO	BOLINAS #2	60.00	60.00	SWP SSP	28.22		1
6	INDUSTRIAL TAP		60.00	60.00	SWP	0.97		1
7	IONE TAP		60.00	60.00	SWP SSP	4.09		1
8	IUKA TAP		60.00	60.00	SWP	0.49		1
9	JANES CREEK TAP		60.00	60.00	SWP	1.78		1
10	JEFFERSON	HILLSDALE JCT	60.00	60.00	T SSP SWP	14.72		1
11	JEFFERSON	LAS PULGAS	60.00	60.00	SWP SSP	6.00		1
12	JEFFERSON	STANFORD	60.00	60.00	SWP SSP	7.64		1
13	JEFFERSON	STANFORD	60.00	60.00	N/A	1.52		1
14	JEFFERSON	LAS PULGAS	60.00	60.00	N/A	0.18		1
15	JEFFERSON #1		60.00	60.00	T SWP	9.05		1
16	JENNINGS TAP		60.00	60.00	SWP	0.14		1
17	JOLON TAP		60.00	60.00	SWP SSP	15.87		1
18	KASSON	CARBONA	60.00	60.00	SWP SSP	7.32		1
19	KASSON	BANTA #1	60.00	60.00	SWP	1.05		1
20	KASSON	LOUISE	60.00	60.00	SWP SSP	8.79		1
21	KASSON #1		60.00	60.00	SWP SSP	0.19		1
22	KESWICK	CASCADE	60.00	60.00	SWP SSP	9.35		1
23	KESWICK	TRINITY	60.00	60.00	SWP SSP	30.42		1
24	KILARC	CEDAR CREEK	60.00	60.00	SWP SSP	13.33		1
25	KILARC	DESCHUTES	60.00	60.00	SWP SSP	27.28		1
26	KILARC	VOLTA TIE	60.00	60.00	T	1.94		1
27	KING CITY	COBURN #1	60.00	60.00	SWP SSP	21.91		1
28	KING CITY	COBURN #2	60.00	60.00	SWP SSP	15.79		1
29	KONOCTI	MIDDLETOWN	60.00	60.00	SWP SSP	19.87		1
30	KONOCTI	EAGLE ROCK	60.00	60.00	SWP SSP	9.66		1
31	LAGUNA TAP		60.00	60.00	SWP SSP	1.68		1
32	LAGUNITAS TAP		60.00	60.00	SWP	0.60		1
33	LAKEVILLE	PETALUMA C	60.00	60.00	SWP SSP	5.36		1
34	LAKEVILLE #1		60.00	60.00	SWP SSP	11.16		1
35	LAKEVILLE #2		60.00	60.00	T SSP SWP	21.62		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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 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	LAS POSITAS	VASCO	60.00	60.00	SWP SSP	1.50		1
2	LAURELES	OTTER	60.00	60.00	SWP SSP	15.56		1
3	LAYTONVILLE	COVELO	60.00	60.00	SWP SSP	16.09		1
4	LAYTONVILLE	WILLITS	60.00	60.00	SWP SSP	23.14		1
5	LEE TAP		60.00	60.00	SWP	5.85		1
6	LIMESTONE TAP		60.00	60.00	SWP	1.73		1
7	LIVERMORE	LAS POSITAS	60.00	60.00	SWP SSP	3.63		1
8	LOCKEFORD	INDUSTRIAL	60.00	60.00	SWP	6.03		1
9	LOCKEFORD	LODI #2	60.00	60.00	SWP SSP	9.41		1
10	LOCKEFORD	LODI #3	60.00	60.00	SWP SSP	15.42		1
11	LOCKEFORD #1		60.00	60.00	SWP SSP	12.85		1
12	LODI	INDUSTRIAL	60.00	60.00	SWP SSP	0.97		1
13	LONE STAR TAP		60.00	60.00	SWP	1.18		1
14	LOS COCHES TAP		60.00	60.00	SWP	1.33		1
15	LOUISIANA PACIFIC		60.00	60.00	SWP	0.16		1
16	LP FLAKEBOARD TAP		60.00	60.00	SWP	0.51		1
17	LYOTH TAP		60.00	60.00	SWP	1.34		1
18	MANTECA	LOUISE	60.00	60.00	SWP SSP	12.53		1
19	MANTECA #1		60.00	60.00	SWP SSP	34.52		1
20	MAPLE CREEK	HOOPA	60.00	60.00	SWP SSP	29.13		1
21	MARSH TAP		60.00	60.00	SWP	3.97		1
22	MARTIN	SNEATH LANE	60.00	60.00	T SSP	7.19		1
23	MCDONALD TAP		60.00	60.00	SWP SSP	5.88		1
24	MENDOCINO	HARTLEY	60.00	60.00	SWP SSP	23.17		1
25	MENDOCINO	PHILO JCT-HOPLAND	60.00	60.00	SWP SSP	23.55		1
26	MENDOCINO	WILLITS	60.00	60.00	SWP SSP	14.52		1
27	MENDOCINO	WILLITS-FORT BRAGG	60.00	60.00	SWP SSP	43.77		1
28	MENDOCINO #1		60.00	60.00	SWP SSP	7.48		1
29	MENLO TAP		60.00	60.00	SWP	0.36		1
30	MIDDLE FORK #1		60.00	60.00	SWP SSP	9.43		1
31	MIDDLE RIVER TAP		60.00	60.00	SWP SSP	7.02		1
32	MILLBRAE	SNEATH LANE	60.00	60.00	T SSP SWP	6.49		1
33	MONTA VISTA	BURNS	60.00	60.00	SWP SSP	18.06		1
34	MONTA VISTA	LOS ALTOS	60.00	60.00	SWP SSP	7.13		1
35	MONTA VISTA	LOS GATOS	60.00	60.00	SWP SSP	10.88		1
36					TOTAL	36,802.57		1,450

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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1	MONTA VISTA	PERMANENTE	60.00	60.00	T SSP SWP	1.19		1
2	MONTE RIO	FORT ROSS	60.00	60.00	SWP SSP	14.30		1
3	MONTE RIO	FULTON	60.00	60.00	SWP SSP	22.56		1
4	MTN GATE JCT	CASCADE	60.00	60.00	SWP OTHERS	6.57		1
5	MTN GATE TAP		60.00	60.00	SWP	0.70		1
6	MTN QUARRIES TAP		60.00	60.00	SWP SSP	2.63		1
7	MULE CREEK TAP		60.00	60.00		0.01		1
8	NARROWS #1 TAP		60.00	60.00	SWP OTHERS	2.65		1
9	NARROWS #2 TAP		60.00	60.00	SWP SSP	3.10		1
10	NAVY LAB TAP		60.00	60.00	SWP	0.19		1
11	NEW HOGAN TAP		60.00	60.00	SWP	2.21		1
12	NEWARK	DECOTO	60.00	60.00	T SSP SWP	6.28		1
13	NEWARK	LIVERMORE	60.00	60.00	T OTHERS	19.05		1
14	NEWARK	VALLECITOS	60.00	60.00	T SSP SWP	12.39		1
15	NEWARK-SIERRA		60.00	60.00	SWP	0.29		1
16	NICOLAUS	CATLETT JCT	60.00	60.00	T SSP SWP	20.16		1
17	NICOLAUS	CATLETT JCT	60.00	60.00	T SSP SWP	18.63		1
18	NICOLAUS	CATLETT JCT (12KV)	60.00	60.00	T SSP SWP	18.63		1
19	NICOLAUS	MARYSVILLE	60.00	60.00	SWP SSP	18.74		1
20	NICOLAUS	PLAINFIELD	60.00	60.00	T SSP SWP	30.63		1
21	NICOLAUS	WILKINS SLOUGH	60.00	60.00	T SSP	42.72		1
22	OAK PARK TAP		60.00	60.00	SWP SSP	0.87		1
23	OILFIELDS	SARGENT CANYON	60.00	60.00	SWP	2.02		1
24	OILFIELDS	SALINAS RIVER	60.00	60.00	SWP	1.46		1
25	ORO FINO TAP		60.00	60.00	SWP	1.30		1
26	OXBOW TAP		60.00	60.00	SWP	0.15		1
27	PACIFIC ETHANOL TAP		60.00	60.00	SWP	0.68		1
28	PACIFIC LUMBER (SCOTIA)		60.00	60.00	SWP OTHERS	0.52		1
29	PACIFIC OROVILLE POWER		60.00	60.00	SWP	0.78		1
30	PALERMO	OROVILLE #1	60.00	60.00	SWP	6.97		1
31	PALERMO	OROVILLE #2	60.00	60.00	SWP SSP	10.13		1
32	PARDEE #1 TAP		60.00	60.00	SWP	4.33		1
33	PARDEE #2 TAP		60.00	60.00	SWP	0.09		1
34	PARKS TAP		60.00	60.00	SWP	0.45		1
35	PEACHTON	PEASE	60.00	60.00	SWP SSP	16.34		1
36					TOTAL	36,802.57		1,450

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1	PEASE	HARTER	60.00	60.00	SWP SSP	15.88		1
2	PEASE	MARYSVILLE-HARTER	60.00	60.00	SWP SSP	10.29		1
3	PERMANENTE #1 TAP		60.00	60.00	SWP	0.31		1
4	PERMANENTE #2 TAP		60.00	60.00	SWP SSP	0.51		1
5	PHILO JCT	ELK	60.00	60.00	SWP SSP	37.25		1
6	PINE GROVE TAP		60.00	60.00	SWP	2.67		1
7	PIT #1	HAT CREEK #2-BURNEY	60.00	60.00	SWP SSP	12.96		1
8	PIT #1	MCARTHUR	60.00	60.00	SWP SSP	7.30		1
9	PITTSBURG #1 TAP (NO		60.00	60.00	SSP	1.15		1
10	PITTSBURG #2 TAP		60.00	60.00	SWP	1.19		1
11	PLACER	DEL MAR	60.00	60.00	SWP SSP	10.81		1
12	PLUMAS-SIERRA TAP		60.00	60.00	SWP	0.75		1
13	PORT COSTA BRICK TAP		60.00	60.00	SWP SSP	1.90		1
14	POTTER VALLEY	MENDOCINO	60.00	60.00	SWP SSP	10.94		1
15	POTTER VALLEY	WILLITS	60.00	60.00	SWP SSP	13.16		1
16	RADUM	LIVERMORE	60.00	60.00	SWP SSP	4.66		1
17	RADUM	VALLECITOS	60.00	60.00	T SSP	10.62		1
18	RED BANK TAP		60.00	60.00	SWP SSP	0.68		1
19	RIO DELL JCT	BRIDGEVILLE	60.00	60.00	SWP SSP	21.25		1
20	RIO DELL TAP		60.00	60.00	SWP SSP	5.36		1
21	ROBERTSON TAP		60.00	60.00	SWP SSP	0.82		1
22	ROLLINS TAP		60.00	60.00	SWP SSP	0.73		1
23	ROUGH & READY TAP		60.00	60.00	SWP SSP	0.95		1
24	SALADO	CROW CREEK SW STA	60.00	60.00	SWP SSP	3.77		1
25	SALADO	NEWMAN #2	60.00	60.00	SWP SSP	21.56		1
26	SALINAS	FORT ORD #1	60.00	60.00	T SSP	10.22		1
27	SALINAS	FIRESTONE #1	60.00	60.00	SWP SSP	6.18		1
28	SALINAS	FIRESTONE #2	60.00	60.00	SWP SSP	17.21		1
29	SALINAS	LAGUNITAS	60.00	60.00	SWP SSP	5.81		1
30	SALINAS	LAURELES	60.00	60.00	SWP SSP	27.46		1
31	SALINAS	FORT ORD #2	60.00	60.00	T SSP SWP	10.12		1
32	SALMON CREEK TAP		60.00	60.00	SWP SSP	10.51		1
33	SAN ANDREAS (CCSF) TAP		60.00	60.00	SWP	0.39		1
34	SAN ARDO TAP		60.00	60.00	SWP SSP	0.34		1
35	SAN BRUNO TAP		60.00	60.00	SWP	1.13		1
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	SAN MATEO	BAIR	60.00	60.00	T SSP	13.99		1
2	SAN MATEO	HILLSDALE JCT	60.00	60.00	SWP SSP	6.89		1
3	SAN RAMON	RADUM	60.00	60.00	SWP	7.06		1
4	SEBASTIANI TAP		60.00	60.00	SWP	0.01		1
5	SENTER #1 TAP		60.00	60.00	SWP	0.23		1
6	SEQUOIA TAP		60.00	60.00	SWP	0.40		1
7	SIERRA PAC IND (QUINCY)		60.00	60.00	SWP	0.17		1
8	SIERRA PINES LIMITED		60.00	60.00	SWP	0.40		1
9	SIMPSON-KORBEL TAP		60.00	60.00	SWP	0.39		1
10	SLAC TAP		60.00	60.00	SWP	1.41		1
11	SMARTVILLE	CAMP FAR WEST	60.00	60.00	SWP SSP	17.81		1
12	SMARTVILLE	CAMP FAR WEST (12KV)	60.00	60.00	SWP SSP	7.15		1
13	SMARTVILLE	MARYSVILLE	60.00	60.00	SWP SSP	20.11		1
14	SMARTVILLE	NICOLAUS #1	60.00	60.00	SWP SSP	29.60		1
15	SMARTVILLE	NICOLAUS #2	60.00	60.00	SWP SSP	30.16		1
16	SMARTVILLE TAP		60.00	60.00	SWP	0.09		1
17	SNEATH LANE	HALF MOON BAY	60.00	60.00	SWP SSP	15.41		1
18	SNEATH LANE	PACIFICA	60.00	60.00	SWP SSP	3.26		1
19	SOLEDAD #1		60.00	60.00	SWP SSP	15.50		1
20	SOLEDAD #2		60.00	60.00	SWP SSP	18.86		1
21	SOLEDAD #3		60.00	60.00	SWP SSP	1.63		1
22	SOLEDAD #4		60.00	60.00	SWP SSP	6.08		1
23	SPAULDING	SUMMIT	60.00	60.00	T SSP	19.65		1
24	SPAULDING #3	SPAULDING #1	60.00	60.00	SWP	1.09		1
25	STAGG	COUNTRY CLUB #1	60.00	60.00	SSP	2.43		1
26	STAGG	COUNTRY CLUB #2	60.00	60.00	SWP SSP	2.46		1
27	STAGG	HAMMER	60.00	60.00	SWP SSP	4.25		1
28	STANDARD #1 & #2 (12KV)		60.00	60.00	T	4.16		1
29	STANISLAUS RECOVERY		60.00	60.00	SWP	0.11		1
30	STAUFFER TAP		60.00	60.00	SWP SSP	0.58		1
31	STOCKTON	NEWARK	60.00	60.00	T SSP SWP	14.59		1
32	STOCKTON A	WEBER #1	60.00	60.00	SWP SSP	13.20		1
33	STOCKTON A	WEBER #2	60.00	60.00	SWP	9.87		1
34	STOCKTON A	WEBER #3	60.00	60.00	SWP SSP	9.81		1
35	STOCKTON A #1		60.00	60.00	T SSP SWP	5.58		1
36					TOTAL	36,802.57		1,450

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	SUMIDEN WIRE PRODUCTS		60.00	60.00	SWP	0.19		1
2	SUNOL TAP		60.00	60.00	SWP OTHERS	0.08		1
3	SUTTER HOME	SUTTER HOME SW STA	60.00	60.00	SSP	0.03		1
4	SUTTER HOME SW STA	LOCKEFORD-LODI	60.00	60.00	SWP SSP	29.74		1
5	SUTTER HOME SW STA	STAGG	60.00	60.00	SWP SSP	17.13		1
6	TABLE MTN	PEACHTON	60.00	60.00	SWP SSP	14.84		1
7	TERMINOUS TAP		60.00	60.00	SWP	3.01		1
8	TEXACO TAP		60.00	60.00	SWP SSP	0.72		1
9	TOCALOMA TAP		60.00	60.00	SWP OTHERS	1.03		1
10	TRAVIS TAP		60.00	60.00	SWP SSP	2.88		1
11	TRINIDAD TAP		60.00	60.00	SWP	1.34		1
12	TRINITY	MAPLE CREEK	60.00	60.00	T SSP	55.45		1
13	TULUCAY	NAPA #1	60.00	60.00	T SSP SWP	9.72		1
14	TULUCAY	NAPA #2	60.00	60.00	SWP SSP	3.93		1
15	ULTRA POWER TAP		60.00	60.00	SWP	1.17		1
16	UNION CHEMICAL TAP		60.00	60.00	SWP	1.04		1
17	URICH TAP		60.00	60.00	SWP	0.21		1
18	US WINDPOWER TAP		60.00	60.00	SWP	1.52		1
19	VACA	PLAINFIELD	60.00	60.00	SWP SSP	29.83		1
20	VALLEY SPRINGS	CALAVERAS CEMENT	60.00	60.00	SWP SSP	7.91		1
21	VALLEY SPRINGS	MARTELL #1	60.00	60.00	SWP SSP	12.75		1
22	VALLEY SPRINGS	CLAY	60.00	60.00	SWP SSP	17.30		1
23	VALLEY SPRINGS #1		60.00	60.00	SWP SSP	27.27		1
24	VALLEY SPRINGS #2		60.00	60.00	SWP SSP	25.65		1
25	VASCO	HERDLYN	60.00	60.00	SWP OTHERS	10.97		1
26	VICTOR TAP		60.00	60.00	SSP	0.06		1
27	VIEJO	MONTEREY	60.00	60.00	SWP SSP	2.28		1
28	VOLTA	DESCHUTES	60.00	60.00	SWP SSP	20.86		1
29	VOLTA	SOUTH	60.00	60.00	SWP SSP	4.86		1
30	WADHAM TAP		60.00	60.00	SWP	1.68		1
31	WASHOE TAP		60.00	60.00	SWP SSP	1.04		1
32	WATERSHED TAP		60.00	60.00	SWP SSP	0.28		1
33	WATSONVILLE	SALINAS	60.00	60.00	SWP SSP	28.39		1
34	WEBER	FRENCH CAMP #1	60.00	60.00	SWP SSP	6.07		1
35	WEBER	FRENCH CAMP #2	60.00	60.00	T SSP SWP	10.89		1
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	WEBER	MORMON JCT	60.00	60.00	SWP SSP	17.67		1
2	WEIMAR	HALSEY	60.00	60.00	SWP SSP	6.28		1
3	WEIMAR #1		60.00	60.00	SWP SSP	13.98		1
4	WEST POINT	VALLEY SPRINGS	60.00	60.00	SWP SSP	21.66		1
5	WEST SAC COM TOWERS		60.00		T SSP	0.02		1
6	WESTINGHOUSE TAP		60.00	60.00	T SWP	7.97		1
7	WILLOW PASS	CONTRA COSTA	60.00	60.00	T SSP SWP	10.82		1
8	WIND FARMS		60.00	60.00	SWP	3.75		1
9	WINDSOR	FITCH MOUNTAIN	60.00	60.00	SWP SSP	21.24		1
10	WINTU TAP		60.00	60.00	SWP	1.86		1
11	WOHLER TAP		60.00	60.00	SWP	1.44		1
12	WOODBRIDGE TAP		60.00	60.00	SWP	0.53		1
13	YUBA CITY COGEN TAP		60.00	60.00	SWP	0.80		1
14	ZOND WIND TAP		60.00	60.00	SWP	1.19		1
15	A	Y #1 (UNDERGROUND IDLE)			N/A	0.35		1
16								
17								
18								
19	Summary of Lines							
20	listed individually above							
21	Towers & Poles		500.00			1,328.00		
22			230.00			5,335.00		
23			115.00			6,114.00		
24			70.00			1,544.00		
25			60.00			3,905.00		
26								
27								
28	Other Undground							
29	Transmission Lines		230.00			86.00		
30			115.00			84.00		
31			70.00					
32			60.00			5.00		
33								
34	Transmission Roads							
35								
36					TOTAL	36,802.57		1,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2300 - AAC - BUND								1
2300 - AAC - BUND								2
2300 - AAC - BUND								3
2300 - AAC - BUND								4
2300 - AAC - BUND								5
2300 - AAC - BUND								6
2300 - AAC - BUND								7
2300 - AAC - BUND								8
2300 - AAC - BUND								9
2156 - ACSR - BUN								10
2300 - AAC - BUND								11
2300 - AAC - BUND								12
2300 - AAC - BUND								13
2300 - AAC - BUND								14
2300 - AAC - BUND								15
2300 - AAC - BUND								16
2300 - AAC - BUND								17
2300 - AAC - BUND								18
2300 - AAC - BUND								19
2300 - AAC - BUND								20
2300 - AAC - BUND								21
795 - ACSR - SING								22
1113 - AAC - SING								23
954 - ACSR - SING								24
1113 - AAC - SING								25
1113 - AAC - SING								26
954 - AAC - SINGL								27
795 - ACSR - SING								28
1113 - AAC - SING								29
954 - ACSS - SING								30
954 - ACSR - SING								31
954 - ACSS - SING								32
954 - AAC - SINGL								33
1113 - ACSS - SIN								34
1113 - ACSS - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1431 - AAC - SING								1
795 - ACSR - SING								2
1113 - AAC - SING								3
1113 - AAC - SING								4
1113 - AAC - SING								5
2300 - AAC - SING								6
795 - ACSR - SING								7
1113 - AAC - SING								8
1113 - AAC - SING								9
795 - ACSR - SING								10
954 - ACSS - SING								11
954 - ACSS - SING								12
1113 - AAC - SING								13
1113 - AAC - SING								14
500 - CU - SINGLE								15
954 - AAC - SINGL								16
954 - AAC - SINGL								17
1113 - AAC - SING								18
795 - ACSS - SING								19
954 - ACSR - SING								20
954 - ACSR - SING								21
954 - ACSS - SING								22
954 - ACSS - SING								23
954 - ACSS - SING								24
954 - ACSS - SING								25
1113 - ACSS - SIN								26
954 - ACSR - SING								27
795 - ACSR - SING								28
954 - ACSR - SING								29
643.7 - SINGLE 95								30
643.7 - SINGLE 11								31
643.7 - SINGLE 95								32
1113 - AAC - SING								33
2300 - AAC - BUND								34
795 - ACSR - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

TRANSMISSION LINE STATISTICS (Continued)

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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.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 - ACSR - SING								1
954 - ACSR - SING								2
954 - ACSR - SING								3
954 - ACSR - SING								4
954 - ACSR - SING								5
1113 - AAC - SING								6
1113 - AAC - SING								7
795 - ACSR - SING								8
954 - ACSS - SING								9
1113 - AAC - SING								10
1113 - AAC - SING								11
643.7 - SINGLE 50								12
1250 KCMIL -								13
1250 KCMIL -								14
2300 - AAC - SING								15
2300 - AAC - SING								16
1113 - AAC - SING								17
3500 KCMIL -								18
1113 - ACSS - SIN								19
1113 - ACSS - SIN								20
1113 - AAC - SING								21
795 - ACSR - SING								22
795 - ACSR - SING								23
795 - ACSR - SING								24
1113 - AAC - SING								25
1431 - AAC - SING								26
1113 - AAC - SING								27
1113 - AAC - SING								28
1113 - AAC - SING								29
1431 - AAC - SING								30
2300 - AAC - BUND								31
3500 KCMIL -								32
954 - ACSR - SING								33
1113 - AAC - SING								34
1113 - AAC - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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.
795 - ACSR - SING								1
1113 - AAC - BUND								2
1113 - AAC - BUND								3
2500 KCMIL - CU								4
2500 KCMIL - CU								5
954 - AAC - SINGL								6
1113 - ACSS - SIN								7
1431 - AAC - BUND								8
1431 - AAC - BUND								9
795 - ACSR - SING								10
1113 - AAC - SING								11
954 - ACSS - SING								12
2300 - AAC - BUND								13
954 - ACSS - SING								14
2500 KCMIL - CU								15
954 - ACSS - SING								16
1113 - AAC - SING								17
2300 - AAC - BUND								18
2156 - ACSS - SIN								19
1 - UNKNOWN -								20
1 - UNKNOWN -								21
1113 - ACSS - SIN								22
795 - ACSR - SING								23
795 - ACSR - SING								24
795 - ACSR - SING								25
2300 - AAC - SING								26
1113 - AAC - SING								27
954 - ACSR - SING								28
954 - ACSS - SING								29
2000 KCMIL - CU								30
795 - ACSR - SING								31
1113 - AAC - SING								32
1113 - AAC - SING								33
1113 - AAC - SING								34
1113 - AAC - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	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)	
795 - ACSS - PARA								1
795 - ACSR - PARA								2
2500 KCMIL - CU								3
954 - ACSR - SING								4
795 - ACSR - SING								5
2300 - AAC - BUND								6
954 - ACSS - SING								7
954 - ACSS - SING								8
1113 - AAC - SING								9
795 - ACSR - SING								10
1113 - AAC - SING								11
1113 - AAC - BUND								12
1113 - AAC - SING								13
1431 - AAC - SING								14
1113 - AAC - SING								15
2300 - AAC - BUND								16
954 - ACSS - SING								17
1113 - AAC - SING								18
1113 - AAC - SING								19
1113 - AAC - SING								20
1431 - AAC - SING								21
954 - ACSR - SING								22
1113 - AAC - SING								23
954 - AAC - SINGL								24
1113 - AAC - SING								25
954 - ACSS - SING								26
954 - ACSS - SING								27
954 - AAC - SINGL								28
795 - ACSR - SING								29
795 - ACSR - SING								30
2300 - AAC - SING								31
1113 - AAC - SING								32
500 - SINGLE								33
1113 - ACSS - SIN								34
1113 - ACSS - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (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.
1113 - AAC - BUND								1
954 - ACSS - BUND								2
2500 KCMIL - CU								3
1113 - AAC - BUND								4
954 - ACSS - SING								5
954 - ACSS - SING								6
2000 KCMIL - CU								7
								8
795 - ACSS - SING								9
1113 - AAC - BUND								10
1113 - ACSS - SIN								11
1113 - ACSS - SIN								12
954 - ACSR - SING								13
1113 - ACSS - SIN								14
500 - CU - SINGLE								15
518 - ACSR - SING								16
795 - ACSR - SING								17
795 - ACSR - SING								18
795 - ACSR - SING								19
795 - ACSR - SING								20
795 - ACSR - SING								21
795 - ACSR - SING								22
795 - ACSR - SING								23
954 - ACSS - SING								24
954 - ACSS - SING								25
954 - ACSS - SING								26
954 - ACSS - SING								27
2300 - AAC - BUND								28
1113 - AAC 954 -								29
954 - ACSS - SING								30
2300 - AAC - BUND								31
795 - ACSR - SING								32
795 - ACSS - PARA								33
1113 - AAC - SING								34
2300 - AAC - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (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)	
2300 - AAC - SING								1
1113 - AAC - BUND								2
1113 - AAC - BUND								3
1113 - AAC - SING								4
795 - ACSR - SING								5
1113 - AAC - SING								6
1113 - AAC - SING								7
795 - ACSR - SING								8
1113 - AAC - SING								9
1113 - AAC - SING								10
795 - ACSR - SING								11
500 - CU - SINGLE								12
1113 - AAC - BUND								13
1113 - AAC - BUND								14
3500 KCMIL								15
954 - ACSR - SING								16
1113 - AAC - SING								17
1113 - AAC - SING								18
954 - ACSS - SING								19
1431 - AAC - SING								20
954 - ACSS - SING								21
954 - ACSS - SING								22
795 - ACSR - SING								23
1113 - AAC - SING								24
795 - ACSR - SING								25
1113 - AAC - SING								26
795 - ACSS - SING								27
795 - ACSS - SING								28
954 - AAC - SINGL								29
1113 - AAC - SING								30
1113 - AAC - SING								31
954 - ACSS - PARA								32
2300 - AAC - BUND								33
2300 - AAC - BUND								34
954 - ACSS - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 - ACSS - SING								1
795 - ACSR - BUND								2
2300 - AAC - BUND								3
2300 - AAC - BUND								4
1113 - AAC - SING								5
1113 - AAC - SING								6
1113 - ACSS - SIN								7
1113 - ACSS - SIN								8
954 - ACSR - SING								9
1113 - AAC - SING								10
954 - ACSR - SING								11
1113 - ACSS - SIN								12
954 - ACSR - SING								13
1113 - ACSS - SIN								14
954 - ACSR - SING								15
954 - ACSS - SING								16
643.7 - SINGLE 50								17
954 - ACSS - SING								18
795 - ACSR - SING								19
2000 KCMIL - CU								20
954 - ACSR - SING								21
954 - ACSS - SING								22
1113 - AAC - SING								23
1113 - AAC - SING								24
795 - ACSR - SING								25
500 - SINGLE 1113								26
1113 - AAC - SING								27
1113 - AAC - SING								28
1113 - AAC - SING								29
2000 KCMIL - CU								30
715.5 - AAC - SIN								31
3500 KCMIL - CU								32
1250 KCMIL - CU								33
1250 KCMIL								34
1250 KCMIL - CU								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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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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)	
3000 KCMIL -								1
1250 KCMIL								2
715.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
								5
715.5 - AAC - SIN								6
4/0 - AAC - SINGL								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
397.5 - AAC - SIN								11
477 - ACSS - SING								12
2500 KCMIL - CU								13
397.5 - AAC - SIN								14
477 - ACSS - SING								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
477 - ACSS - SING								21
715.5 - AAC - SIN								22
4/0 - AAC - SINGL								23
2300 - AAC - SING								24
715.5 - AAC - SIN								25
4/0 - ACSR - SING								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
								31
1113 - AAC - SING								32
4/0 - AAC - SINGL								33
4/0 - AAC - SINGL								34
4/0 - AAC - SINGL								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 - ACSR - SI								1
3/0 - CU - SINGLE								2
3/0 - CU - SINGLE								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
477 - ACSS - SING								10
397.5 - ACSR - SI								11
397.5 - ACSR - SI								12
397.5 - AAC - SIN								13
715.5 - AAC - SIN								14
795 - ACSR - SING								15
3500 KCMIL - CU								16
3000 KCMIL								17
1250 KCMIL - CU								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
477 - ACSS - SING								22
715.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
715.5 - AAC - SIN								25
397.5 - AAC - SIN								26
715.5 - AAC - SIN								27
397.5 - AAC - SIN								28
397.5 - AAC - SIN								29
715.5 - AAC - SIN								30
250 - CU - SINGLE								31
397.5 - AAC - SIN								32
397.5 - AAC - SIN								33
250 - CU - SINGLE								34
397.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 - ACSR - SI								1
397.5 - AAC - SIN								2
4/0 - ACSR - SING								3
715.5 - AAC - SIN								4
397.5 - AAC - SIN								5
715.5 - AAC - SIN								6
397.5 - AAC - SIN								7
397.5 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
1113 - AAC - SING								12
3/0 - CU - SINGLE								13
715.5 - AAC - SIN								14
1113 - AAC - SING								15
477 - ACSS - SING								16
397.5 - ACSR - SI								17
397.5 - AAC - SIN								18
250 - CU - SINGLE								19
477 - ACSS - SING								20
2/0 - CU - SINGLE								21
3/0 - CU - SINGLE								22
477 - ACSS - SING								23
397.5 - AAC - SIN								24
3000 KCMIL								25
477 - ACSS - SING								26
4/0 - AAC - SINGL								27
4/0 - AAC - SINGL								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
477 - ACSS - SING								34
266.8 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
266.8 - AAC - SIN								1
397.5 - ACSR - SI								2
715.5 - AAC - SIN								3
266.8 - AAC - SIN								4
266.8 - AAC - SIN								5
397.5 - ACSR - SI								6
397.5 - ACSR - SI								7
715.5 - AAC - SIN								8
250 - CU - SINGLE								9
795 - ACSS - SING								10
								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
477 - ACSS - SING								15
3000 KCMIL -								16
477 - ACSS - BUND								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
397.5 - AAC - SIN								20
								21
500 KCMIL								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - PAR								28
4/0 - AAC - SINGL								29
								30
715.5 - AAC 397.5								31
715.5 - AAC 397.5								32
266.8 - AAC - SIN								33
								34
266.8 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
								4
4/0 - AAC - SINGL								5
4/0 - AAC - SINGL								6
795 - ACSS - SING								7
397.5 - ACSR - SI								8
4/0 - AAC - SINGL								9
2/0 - CU - SINGLE								10
2/0 - CU - SINGLE								11
715.5 - AAC - SIN								12
477 - ACSS - SING								13
477 - ACSS - SING								14
477 - ACSS - SING								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
1113 - AAC - SING								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - BUN								24
1 - UNKNOWN -								25
715.5 - AAC - SIN								26
477 - ACSS - SING								27
4/0 - AAC - SINGL								28
397.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
4/0 - AAC - SINGL								2
4/0 - AAC - SINGL								3
1113 - AAC - SING								4
715.5 - AAC - SIN								5
3500 KCMIL - CU								6
1000 KCMIL - CU								7
1250 KCMIL - CU								8
1250 KCMIL - CU								9
4/0 - AAC - SINGL								10
1113 - AAC - SING								11
477 - ACSS 1431 -								12
954 - ACSS - SING								13
954 - ACSS - SING								14
1431 - AAC - SING								15
1113 - AAC - SING								16
715.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
4/0 - AAC - SINGL								19
397.5 - ACSR - SI								20
4/0 - ACSR - SING								21
397.5 - AAC - SIN								22
397.5 - AAC - SIN								23
397.5 - AAC - SIN								24
397.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
2 - UNKNOWN -								30
4/0 - AAC - SINGL								31
4/0 - AAC - SINGL								32
715.5 - AAC - SIN								33
397.5 - ACSR - SI								34
2000 KCMIL - CU								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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.
3000 KCMIL - CU								1
4/0 - AAC - SINGL								2
4/0 - ACSR - SING								3
1113 - AAC - SING								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
AAC - SINGLE 266.								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
397.5 - AAC - SIN								25
397.5 - ACSR - SI								26
397.5 - AAC - SIN								27
477 - ACSS - SING								28
477 - ACSS - SING								29
2500 KCMIL - CU								30
715.5 - AAC - SIN								31
477 - ACSS - SING								32
477 - ACSS - SING								33
4/0 - AAC - SINGL								34
4/0 - AAC - SINGL								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
1113 - AAC - SING								1
250 - CU - SINGLE								2
954 - ACSS - SING								3
2/0 - CU - SINGLE								4
715.5 - AAC - SIN								5
1113 - AAC - SING								6
715.5 - AAC - SIN								7
4/0 - AAC - SINGL								8
1113 - AAC - SING								9
1113 - AAC - SING								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
397.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - BUN								17
3/0 - CU - SINGLE								18
397.5 - AAC - SIN								19
397.5 - AAC - SIN								20
795 - ACSS - SING								21
795 - ACSS - SING								22
715.5 - AAC - SIN								23
715.5 - AAC - BUN								24
4/0 - AAC - SINGL								25
4/0 - ACSR - SING								26
4/0 - ACSR - SING								27
715.5 - AAC - SIN								28
3/0 - CU - SINGLE								29
1113 - AAC - SING								30
1431 - AAC - SING								31
477 - ACSS - SING								32
715.5 - AAC - SIN								33
397.5 - AAC - SIN								34
397.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
477 - ACSS - SING								1
477 - ACSS - SING								2
477 - ACSS - SING								3
3000 KCMIL -								4
3000 KCMIL -								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
477 - ACSS - SING								13
477 - ACSS - SING								14
1113 - AAC - SING								15
477 - ACSS - SING								16
477 - ACSS - SING								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
397.5 - ACSR - SI								20
715.5 - AAC - SIN								21
397.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
2/0 - CU - SINGLE								27
2/0 - CU - SINGLE								28
397.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
477 - ACSS - SING								32
477 - ACSS - SING								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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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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.
715.5 - AAC - SIN								1
1 - UNKNOWN -								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
1113 - AAC - SING								5
266.8 - AAC - SIN								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
336.4 - AAC - SIN								9
								10
477 - ACSS - SING								11
1113 - AAC - SING								12
4/0 - AAC - SINGL								13
477 - ACSS - SING								14
397.5 - ACSR - SI								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
477 - ACSS - SING								19
CU								20
795 - ACSS - SING								21
4/0 - AAC - SINGL								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
3/0 - CU - SINGLE								25
3/0 - CU - SINGLE								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
954 - ACSR - SING								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
477 - ACSS - SING								4
477 - ACSS - SING								5
477 - ACSS - SING								6
477 - ACSS - SING								7
477 - ACSS - SING								8
477 - ACSS - SING								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
477 - ACSS - SING								14
477 - ACSS - SING								15
477 - ACSS - SING								16
477 - ACSS - SING								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
477 - ACSS - SING								21
3/0 - CU - SINGLE								22
477 - ACSS - SING								23
1113 - AAC - SING								24
4/0 - CU - SINGLE								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
2500 KCMIL - CU								30
795 - ACSS - SING								31
1 - UNKNOWN -								32
477 - ACCR - SING								33
477 - ACSS - SING								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
4/0 - ACSR - SING								1
4/0 - ACSR - SING								2
715.5 - AAC - SIN								3
715.5 - AAC - PAR								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
250 - CU - SINGLE								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
4/0 - AAC - SINGL								13
4/0 - AAC - SINGL								14
4/0 - AAC - SINGL								15
								16
1000 KCMIL - CU								17
1000 KCMIL - CU								18
1113 - AAC - SING								19
1113 - AAC - SING								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - BUN								23
477 - ACSS - SING								24
477 - ACSS - SING								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
4/0 - AAC - SINGL								30
336.4 - ACSR - SI								31
4/0 - AAC - SINGL								32
397.5 - ACSR - SI								33
477 - ACSS - SING								34
715.5 - AAC - PAR								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
715.5 - AAC - BUN								1
715.5 - AAC - BUN								2
715.5 - AAC - SIN								3
2300 - AAC - BUND								4
2300 - AAC - BUND								5
715.5 - AAC - SIN								6
477 - ACSS - SING								7
477 - ACSS - SING								8
3000 KCMIL - CU								9
3000 KCMIL - CU								10
2300 - AAC - SING								11
2300 - AAC - SING								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
4/0 - AAC - SINGL								16
397.5 - AAC - SIN								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
477 - ACSS - SING								20
477 - ACSS - SING								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
397.5 - AAC - SIN								29
397.5 - AAC - SIN								30
266.8 - AAC - SIN								31
4/0 - AAC - SINGL								32
4/0 - AAC - SINGL								33
1113 - AAC - SING								34
1113 - AAC - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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	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)	
1113 - AAC - SING								1
336.4 - ACSR - SI								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
397.5 - AAC - SIN								5
4/0 - ACSR - SING								6
477 - ACSS - SING								7
4/0 - CU - SINGLE								8
477 - ACSS - SING								9
1 - UNKNOWN -								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
1113 - AAC - SING								13
715.5 - AAC - SIN								14
397.5 - ACSR - SI								15
397.5 - ACSR - SI								16
715.5 - AAC - SIN								17
336.4 - AAC - SIN								18
4/0 - CU - SINGLE								19
4/0 - CU - SINGLE								20
715.5 - AAC - SIN								21
477 - ACSS - SING								22
477 - ACSS - SING								23
477 - ACSS - SING								24
3000 KCMIL -								25
3000 KCMIL -								26
3000 KCMIL -								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
397.5 - ACSR - SI								30
715.5 - AAC - SIN								31
1113 - AAC - SING								32
1113 - AAC - SING								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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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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)	
397.5 - AAC - SIN								1
397.5 - AAC - SIN								2
477 - ACSS - SING								3
397.5 - AAC - SIN								4
1 - UNKNOWN -								5
954 - ACSS - SING								6
477 - ACSS - SING								7
397.5 - AAC - SIN								8
1113 - AAC - SING								9
715.5 - AAC - SIN								10
397.5 - AAC - SIN								11
477 - ACSS - SING								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
2/0 - CU - SINGLE								15
4/0 - CU - SINGLE								16
4/0 - CU - SINGLE								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
4/0 - CU - SINGLE								20
397.5 - AAC - SIN								21
715.5 - AAC - SIN								22
4/0 - AAC - SINGL								23
4/0 - AAC - SINGL								24
4/0 - ACSR - SING								25
266.8 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
1113 - AAC - SING								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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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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)	
3000 KCMIL -								1
								2
715.5 - AAC - SIN								3
397.5 - ACSR - SI								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
2/0 - CU - SINGLE								8
2/0 - CU - SINGLE								9
477 - ACSS - SING								10
477 - ACSS - SING								11
CU								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
397.5 - AAC - SIN								16
397.5 - AAC - SIN								17
477 - ACSS - SING								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
4/0 - AAC - SINGL								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
1113 - AAC - SING								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
								34
336.4 - ACAR - SI								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	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)	
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
1113 - AAC - SING								6
4/0 - AAC - SINGL								7
397.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
3/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
1113 - AAC - SING								20
715.5 - AAC - SIN								21
477 - ACSS - SING								22
715.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
4/0 - AAC - SINGL								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
266.8 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
266.8 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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 (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.
4/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
4/0 - AAC - SINGL								3
715.5 - AAC - SIN								4
2300 - AAC - SING								5
1250 KCMIL - CU								6
397.5 - AAC - SIN								7
715.5 - AAC - SIN								8
4/0 - AAC - SINGL								9
397.5 - ALUM - SI								10
4/0 - AAC - SINGL								11
2 - ACSR - SINGLE								12
715.5 - AAC - SIN								13
397.5 - AAC - SIN								14
715.5 - AAC - SIN								15
3/0 - AAC - SINGL								16
715.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
3/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
1/0 - ACSR - SING								21
397.5 - AAC - SIN								22
1/0 - ACSR - SING								23
4/0 - AAC - SINGL								24
4/0 - AAC - SINGL								25
715.5 - AAC - SIN								26
2 - CU - SINGLE								27
4/0 - CU - SINGLE								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
1750 KCMIL -								32
4/0 - ACSR - SING								33
715.5 - AAC - SIN								34
397.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	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)	
715.5 - AAC - SIN								1
266.8 - AAC - SIN								2
4/0 - AAC - SINGL								3
4/0 - AAC - SINGL								4
3/0 - AAC - SINGL								5
3/0 - AAC - SINGL								6
2 - ACSR - SINGLE								7
4/0 - AAC - SINGL								8
307.1 - AAC - SIN								9
4/0 - AAC - SINGL								10
397.5 - AAC - SIN								11
4/0 - AAC - SINGL								12
1113 - AAC - SING								13
266.8 - ACSR - SI								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
4/0 - CU - SINGLE								18
1113 - AAC - SING								19
1113 - AAC - SING								20
1113 - AAC - SING								21
1113 - AAC - SING								22
397.5 - AAC - SIN								23
2/0 - CU - SINGLE								24
715.5 - AAC - SIN								25
397.5 - AAC - SIN								26
266.8 - AAC - SIN								27
715.5 - AAC - SIN								28
397.5 - AAC - SIN								29
715.5 - AAC - SIN								30
1/0 - ACSR - SING								31
397.5 - AAC - SIN								32
1/0 - ACSR - SING								33
715.5 - AAC - SIN								34
3/0 - ACSR - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	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)	
715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
4/0 - CU - SINGLE								5
4/0 - AAC - SINGL								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
1113 - AAC - SING								11
1/0 - ACSR - SING								12
266.8 - AAC - SIN								13
477 - ACSS - SING								14
397.5 - AAC - SIN								15
4/0 - ACSR - SING								16
266.8 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
4/0 - CU - SINGLE								26
4/0 - AAC - SINGL								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
1113 - AAC - SING								30
1113 - AAC - SING								31
1/0 - ACSR - SING								32
715.5 - AAC - SIN								33
397.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
715.5 - AAC - SIN								1
795 - ACSS - SING								2
1/0 - CU - SINGLE								3
397.5 - AAC - SIN								4
715.5 - AAC - SIN								5
3/0 - CU - SINGLE								6
1/0 - ACSR - SING								7
4/0 - AAC - SINGL								8
1 - UNKNOWN -								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
1/0 - ACSR - SING								15
715.5 - AAC - SIN								16
1/0 - CU - SINGLE								17
4/0 - AAC - SINGL								18
715.5 - AAC - SIN								19
397.5 - AAC - SIN								20
715.5 - AAC - SIN								21
2 - UNKNOWN -								22
3/0 - CU - SINGLE								23
715.5 - AAC - SIN								24
397.5 - AAC - SIN								25
4/0 - AAC - SINGL								26
4/0 - AAC - SINGL								27
397.5 - AAC - SIN								28
266.8 - AAC - SIN								29
1113 - AAC - SING								30
715.5 - AAC - SIN								31
4/0 - AAC - SINGL								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
1/0 - ACSR - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	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) 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.
4/0 - AAC - SINGL								1
4/0 - AAC - SINGL								2
4/0 - AAC - SINGL								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
4/0 - AAC - SINGL								7
266.8 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - CU - SINGLE								10
1113 - AAC - SING								11
715.5 - AAC - SIN								12
3/0 - AAC - SINGL								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
2 - ACSR - SINGLE								16
4 - CU - SINGLE 4								17
3/0 - CU - SINGLE								18
1/0 - ACSR - SING								19
1/0 - ACSR - SING								20
1113 - AAC - SING								21
397.5 - AAC - SIN								22
4/0 - AAC - SINGL								23
4/0 - AAC - SINGL								24
397.5 - AAC - SIN								25
1/0 - ACSR - SING								26
1/0 - CU - SINGLE								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
4/0 - AAC - SINGL								30
2 - ACSR - SINGLE								31
1/0 - ACSR - SING								32
715.5 - AAC - SIN								33
397.5 - ACSR - SI								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	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)	
3/0 - CU - SINGLE								1
336.4 - AAC - SIN								2
1 - CU - SINGLE								3
4/0 - AAC - SINGL								4
397.5 - AAC - SIN								5
336.4 - AAC - SIN								6
2/0 - CU - SINGLE								7
1/0 - ACSR - SING								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
2/0 - CU - SINGLE								11
4/0 - CU - SINGLE								12
715.5 - AAC - SIN								13
477 - ACSS - SING								14
2/0 - CU - SINGLE								15
2/0 - CU - SINGLE								16
477 - ACSS - SING								17
477 - ACSS - SING								18
4/0 - AAC - SINGL								19
4/0 - AAC - SINGL								20
4/0 - ACAR - SING								21
4/0 - ACSR - SING								22
4/0 - AAC - SINGL								23
715.5 - AAC - SIN								24
1/0 - ACSR - SING								25
3/0 - CU - SINGLE								26
3/0 - CU - SINGLE								27
397.5 - AAC - SIN								28
4/0 - AAC - SINGL								29
4/0 - ALUM - SING								30
1/0 - ACSR - SING								31
2 - ACSR - SINGLE								32
2 - ACSR - SINGLE								33
397.5 - AAC - SIN								34
397.5 - ACSR - SI								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 - ACSR - SING								1
397.5 - ACSR - SI								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
350 - AAC - SINGL								5
1 - UNKNOWN -								6
715.5 - AAC - SIN								7
336.4 - AAC - SIN								8
3/0 - CU - SINGLE								9
1 - UNKNOWN -								10
397.5 - AAC - SIN								11
2 - ACSR - SINGLE								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
								16
1431 - AAC - BUND								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
1/0 - CU - SINGLE								22
715.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
4 - ACSR - SINGLE								25
4/0 - ACSR - SING								26
2/0 - CU - SINGLE								27
715.5 - AAC - SIN								28
477 - ACSS - SING								29
4/0 - CU - SINGLE								30
1113 - AAC - BUND								31
2 - ACSR - SINGLE								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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4/0 - CU - SINGLE								1
397.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
2000 KCMIL -								6
1 - CU - SINGLE 2								7
2/0 - CU - SINGLE								8
1/0 - ACSR - SING								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
250 - CU - SINGLE								15
300 - AAC - SINGL								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
715.5 - SINGLE								19
4/0 - CU - SINGLE								20
4/0 - CU - SINGLE								21
1/0 - ACSR - SING								22
4/0 - AAC - SINGL								23
397.5 - AAC - SIN								24
2/0 - CU - SINGLE								25
477 - ACSS - SING								26
715.5 - AAC - SIN								27
3000 KCMIL - CU								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
518 - ACSR - SING								33
350 - AAC - SINGL								34
4 - CU - SINGLE								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

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

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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)	
6 - CU - SINGLE 2								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
397.5 - ACSR - SI								4
4/0 - CU - SINGLE								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
4/0 - ACSR - SING								8
1/0 - CU - SINGLE								9
2 - ACSR - SINGLE								10
4 - CU - SINGLE								11
715.5 - AAC - SIN								12
2/0 - CU - SINGLE								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
4/0 - CU - SINGLE								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
477 - ACSS - SING								20
2/0 - CU - SINGLE								21
350 - AAC - SINGL								22
397.5 - AAC - SIN								23
715.5 - AAC - SIN								24
4/0 - ACSR - SING								25
4/0 - ACSR - SING								26
2/0 - CU - SINGLE								27
4/0 - ACSR - SING								28
477 - ACSS - SING								29
4/0 - AAC - SINGL								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
1/0 - ACSR - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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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715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
2/0 - CU - SINGLE								7
2/0 - CU - SINGLE								8
4/0 - AAC - SINGL								9
397.5 - AAC - SIN								10
715.5 - AAC - SIN								11
1/0 - ACSR - SING								12
4/0 - AAC - SINGL								13
715.5 - AAC - SIN								14
397.5 - AAC - SIN								15
397.5 - AAC - SIN								16
4/0 - ACSR - SING								17
715.5 - AAC - SIN								18
1/0 - ACSR - SING								19
4/0 - AAC - SINGL								20
1/0 - ACSR - SING								21
4/0 - CU - SINGLE								22
4/0 - AAC - SINGL								23
4/0 - AAC - SINGL								24
471 - AAC - SINGL								25
1/0 - CU - SINGLE								26
397.5 - AAC - SIN								27
715.5 - AAC - SIN								28
4/0 - ACSR - SING								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
1113 - AAC - SING								33
1113 - AAC - SING								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
4/0 - ACSR - SING								3
4/0 - ACSR - SING								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
4/0 - AAC - SINGL								7
4 - CU - SINGLE								8
4/0 - AAC - SINGL								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
								13
1750 KCMIL -								14
715.5 - AAC - SIN								15
336.4 - AAC - SIN								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
4/0 - AAC - SINGL								22
336.4 - ACSR - SI								23
1/0 - ACSR - SING								24
2 - ACSR - SINGLE								25
1/0 - ACSR - SING								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
								32
250 - CU - SINGLE								33
397.5 - AAC - SIN								34
1/0 - CU - SINGLE								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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.
715.5 - AAC - SIN								1
4/0 - ACSR - SING								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
4/0 - AAC - SINGL								5
2 - ACSR - SINGLE								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
								13
4/0 - AAC - SINGL								14
1/0 - ACSR - SING								15
397.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
1/0 - CU - SINGLE								19
1/0 - ACSR - SING								20
1/0 - ACSR - SING								21
715.5 - AAC - SIN								22
1/0 - ACSR - SING								23
4/0 - ACSR - SING								24
3/0 - CU - SINGLE								25
2/0 - CU - SINGLE								26
715.5 - ALUM - SI								27
3/0 - CU - SINGLE								28
715.5 - AAC - BUN								29
4/0 - ACSR - SING								30
3 - CU - SINGLE 3								31
715.5 - AAC - SIN								32
3/0 - CU - SINGLE								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
2/0 - CU - SINGLE								4
1/0 - ACSR - SING								5
397.5 - AAC - SIN								6
4/0 - AAC - SINGL								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
2 - CU - SINGLE								10
1/0 - ACSR - SING								11
715.5 - AAC - SIN								12
4/0 - CU - SINGLE								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
4/0 - CU - SINGLE								19
715.5 - AAC - SIN								20
4 - CU - SINGLE 3								21
4 - CU - SINGLE								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
2 - ACSR - SINGLE								25
4/0 - ACSR - SING								26
715.5 - AAC - SIN								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
2/0 - CU - SINGLE								32
2/0 - CU - SINGLE								33
1/0 - ACSR - SING								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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)	
715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
397.5 - AAC - SIN								3
397.5 - AAC - SIN								4
397.5 - ACSR - SI								5
397.5 - ACSR - SI								6
3/0 - CU - SINGLE								7
1/0 - ACSR - SING								8
4/0 - CU - SINGLE								9
3/0 - CU - SINGLE								10
715.5 - AAC - SIN								11
397.5 - ACSR - SI								12
3/0 - CU - SINGLE								13
3/0 - CU - SINGLE								14
1/0 - ACSR - SING								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
1/0 - ACSR - SING								18
1/0 - CU - SINGLE								19
1/0 - CU - SINGLE								20
1/0 - ACSR - SING								21
4/0 - ACSR - SING								22
4/0 - AAC - SINGL								23
715.5 - ACSR - SI								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
4/0 - CU - SINGLE								29
266.8 - AAC - SIN								30
715.5 - AAC - SIN								31
397.5 - AAC - SIN								32
397.5 - AAC - SIN								33
715.5 - AAC - SIN								34
1/0 - ACSR - SING								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	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)	
397.5 - AAC - PAR								1
397.5 - AAC - SIN								2
715.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
336.4 - AAC - SIN								5
4/0 - AAC - SINGL								6
								7
4/0 - AAC - SINGL								8
4/0 - AAC - SINGL								9
397.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
4/0 - AAC - SINGL								20
397.5 - AAC - SIN								21
397.5 - AAC - SIN								22
4/0 - CU - SINGLE								23
1/0 - CU - SINGLE								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
1 - UNKNOWN -								28
397.5 - AAC - SIN								29
1/0 - ACSR - SING								30
3/0 - CU - SINGLE								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 - AAC - SIN								1
4/0 - AAC - SINGL								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
2/0 - ACSR - SING								7
397.5 - AAC - SIN								8
2 - ACSR - SINGLE								9
715.5 - AAC - SIN								10
1 - CU - SINGLE								11
4/0 - ACSR - SING								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
4/0 - AAC - SINGL								15
715.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
4/0 - AAC - SINGL								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
1113 - AAC - SING								21
715.5 - AAC - SIN								22
1113 - AAC - SING								23
1113 - AAC - SING								24
715.5 - AAC - SIN								25
4/0 - AAC - SINGL								26
715.5 - AAC - SIN								27
2/0 - CU - SINGLE								28
1 - CU - SINGLE 2								29
4/0 - AAC - SINGL								30
4/0 - AAC - SINGL								31
4/0 - AAC - SINGL								32
3/0 - CU - SINGLE								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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715.5 - AAC - SIN								1
397.5 - AAC - SIN								2
80 - ACSR - SINGL								3
715.5 - AAC - SIN								4
								5
4/0 - CU - SINGLE								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
4/0 - ACSR - SING								9
1/0 - ACSR - SING								10
2 - ACSR - SINGLE								11
4/0 - AAC - SINGL								12
477 - ACSS - SING								13
								14
1250 KCMIL - CU								15
								16
								17
								18
								19
								20
	29,217,173	461,063,372	490,280,545	1,594,870	9,529,274		11,124,144	21
	77,883,619	1,757,640,266	1,835,523,885	6,408,707	38,291,725		44,700,432	22
	92,589,376	1,052,639,078	1,145,228,454	7,344,486	43,882,962		51,227,448	23
	14,828,234	225,301,498	240,129,732	1,854,741	11,081,991		12,936,732	24
	34,646,232	528,067,383	562,713,615	4,690,909	28,027,963		32,718,872	25
								26
								27
								28
	2,790,742	238,509,403	241,300,145	139,269	839,038		978,307	29
	122,163	516,524,425	516,646,588	136,226	820,704		956,930	30
								31
		21,150,299	21,150,299	8,733	52,614		61,347	32
								33
		103,255,426	103,255,426					34
								35
	252,077,539	4,904,151,150	5,156,228,689	22,177,941	132,526,271		154,704,212	36

Schedule Page: 422 Line No.: 1 Column: a
BUNDLE

Schedule Page: 422 Line No.: 1 Column: e
SSP - Single Steel Poles; SWP - Single Wood Poles; WH - Wood "H" Structures; T - Steel Towers; UG - Underground

Schedule Page: 422 Line No.: 2 Column: a
BUNDLE

Schedule Page: 422 Line No.: 3 Column: a
BUNDLE

Schedule Page: 422 Line No.: 4 Column: a
BUNDLE

Schedule Page: 422 Line No.: 5 Column: a
BUNDLE

Schedule Page: 422 Line No.: 6 Column: a
BUNDLE

Schedule Page: 422 Line No.: 7 Column: a
BUNDLE

Schedule Page: 422 Line No.: 8 Column: a
BUNDLE

Schedule Page: 422 Line No.: 9 Column: a
BUNDLE

Schedule Page: 422 Line No.: 10 Column: a
BUNDLE

Schedule Page: 422 Line No.: 11 Column: a
BUNDLE

Schedule Page: 422 Line No.: 12 Column: a
BUNDLE

Schedule Page: 422 Line No.: 13 Column: a
BUNDLE

Schedule Page: 422 Line No.: 14 Column: a
BUNDLE

Schedule Page: 422 Line No.: 15 Column: a
BUNDLE

Schedule Page: 422 Line No.: 16 Column: a
BUNDLE

Schedule Page: 422 Line No.: 17 Column: a
BUNDLE

Schedule Page: 422 Line No.: 18 Column: a
BUNDLE

Schedule Page: 422 Line No.: 19 Column: a
BUNDLE

Schedule Page: 422 Line No.: 20 Column: a
BUNDLE

Schedule Page: 422 Line No.: 21 Column: a
BUNDLE

Schedule Page: 422 Line No.: 24 Column: a
BUNDLE

Schedule Page: 422 Line No.: 30 Column: a
BUNDLE

Schedule Page: 422 Line No.: 32 Column: a
BUNDLE

Schedule Page: 422.1 Line No.: 3 Column: a
BUNDLE

Schedule Page: 422.1 Line No.: 34 Column: a
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Schedule Page: 422.2 Line No.: 15 Column: a
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Schedule Page: 422.2 Line No.: 17 Column: a
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Schedule Page: 422.2 Line No.: 25 Column: a
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Schedule Page: 422.2 Line No.: 28 Column: a
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Schedule Page: 422.2 Line No.: 31 Column: a
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Schedule Page: 422.3 Line No.: 1 Column: a
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Schedule Page: 422.3 Line No.: 2 Column: a
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Schedule Page: 422.5 Line No.: 4 Column: a
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Schedule Page: 422.6 Line No.: 3 Column: a
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Schedule Page: 422.6 Line No.: 13 Column: a
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Schedule Page: 422.6 Line No.: 14 Column: a
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Schedule Page: 422.6 Line No.: 33 Column: a
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Schedule Page: 422.6 Line No.: 34 Column: a
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Schedule Page: 422.7 Line No.: 3 Column: a
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Schedule Page: 422.7 Line No.: 4 Column: a
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Schedule Page: 422.7 Line No.: 11 Column: a

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Schedule Page: 422.9 Line No.: 3 Column: a
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Schedule Page: 422.9 Line No.: 5 Column: a
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Schedule Page: 422.9 Line No.: 6 Column: a
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Schedule Page: 422.9 Line No.: 7 Column: a
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Schedule Page: 422.9 Line No.: 8 Column: a
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Schedule Page: 422.9 Line No.: 9 Column: a
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Schedule Page: 422.9 Line No.: 14 Column: a
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Schedule Page: 422.11 Line No.: 14 Column: a
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Schedule Page: 422.11 Line No.: 17 Column: a
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Schedule Page: 422.12 Line No.: 24 Column: a
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Schedule Page: 422.12 Line No.: 25 Column: a
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Schedule Page: 422.13 Line No.: 10 Column: a
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Schedule Page: 422.14 Line No.: 8 Column: a
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Schedule Page: 422.14 Line No.: 14 Column: a
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Schedule Page: 422.15 Line No.: 17 Column: a
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Schedule Page: 422.15 Line No.: 24 Column: a
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Schedule Page: 422.16 Line No.: 27 Column: a
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Schedule Page: 422.16 Line No.: 28 Column: a
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Schedule Page: 422.16 Line No.: 30 Column: a
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Schedule Page: 422.16 Line No.: 31 Column: a
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Schedule Page: 422.17 Line No.: 2 Column: a
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Schedule Page: 422.17 Line No.: 10 Column: a
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Schedule Page: 422.18 Line No.: 2 Column: a
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Schedule Page: 422.18 Line No.: 3 Column: a
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Schedule Page: 422.18 Line No.: 32 Column: a
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Schedule Page: 422.19 Line No.: 23 Column: a

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Schedule Page: 422.19 Line No.: 35 Column: a

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Schedule Page: 422.20 Line No.: 1 Column: a

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Schedule Page: 422.20 Line No.: 2 Column: a

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Schedule Page: 422.20 Line No.: 4 Column: a

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Schedule Page: 422.20 Line No.: 5 Column: a

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Schedule Page: 422.20 Line No.: 31 Column: a

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Schedule Page: 422.21 Line No.: 10 Column: a

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Schedule Page: 422.22 Line No.: 5 Column: a

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Schedule Page: 422.22 Line No.: 16 Column: a

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Schedule Page: 422.22 Line No.: 17 Column: a

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Schedule Page: 422.22 Line No.: 27 Column: a

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Schedule Page: 422.23 Line No.: 8 Column: a

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Schedule Page: 422.23 Line No.: 9 Column: a

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Schedule Page: 422.23 Line No.: 30 Column: a

BUNDLE

Schedule Page: 422.24 Line No.: 17 Column: a

ALUM

Schedule Page: 422.24 Line No.: 30 Column: a

IDLE

Schedule Page: 422.25 Line No.: 10 Column: a

ALUM

Schedule Page: 422.26 Line No.: 29 Column: a

IDLE

Schedule Page: 422.28 Line No.: 9 Column: a

IDLE

Schedule Page: 422.29 Line No.: 6 Column: a

IDLE

Schedule Page: 422.29 Line No.: 8 Column: a

IDLE

Schedule Page: 422.29 Line No.: 15 Column: a

ALUM

Schedule Page: 422.29 Line No.: 18 Column: a

ALUM

Schedule Page: 422.30 Line No.: 5 Column: a

IDLE

Schedule Page: 422.30 Line No.: 30 Column: a

ALUM

Schedule Page: 422.31 Line No.: 6 Column: a

IDLE

Schedule Page: 422.31 Line No.: 10 Column: a

IDLE

Schedule Page: 422.31 Line No.: 17 Column: a

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Schedule Page: 422.31 Line No.: 31 Column: a

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Schedule Page: 422.32 Line No.: 1 Column: a

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Schedule Page: 422.32 Line No.: 4 Column: a

IDLE

Schedule Page: 422.32 Line No.: 5 Column: a

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Schedule Page: 422.32 Line No.: 30 Column: a

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Schedule Page: 422.33 Line No.: 33 Column: a

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Schedule Page: 422.34 Line No.: 2 Column: a

BUNDLE

Schedule Page: 422.36 Line No.: 5 Column: a

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Schedule Page: 422.36 Line No.: 27 Column: a

ALUM

Schedule Page: 422.36 Line No.: 29 Column: a

BUNDLE

Schedule Page: 422.37 Line No.: 12 Column: a

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Schedule Page: 422.37 Line No.: 17 Column: a

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Schedule Page: 422.37 Line No.: 18 Column: a

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Schedule Page: 422.37 Line No.: 34 Column: a

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Schedule Page: 422.38 Line No.: 9 Column: a

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Schedule Page: 422.39 Line No.: 6 Column: a

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Schedule Page: 422.39 Line No.: 12 Column: a

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Schedule Page: 422.39 Line No.: 28 Column: a

IDLE

Schedule Page: 422.39 Line No.: 31 Column: a

IDLE

Schedule Page: 422.40 Line No.: 23 Column: a

BUNDLE

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	RECONDUCTORING WORK						
2	OVERHEAD						
3							
4	Semitropic-Midway						
5	Semitropic Sub	Midway Substation	14.20	Various	17.00	1	1
6	Job Order #74001000						
7							
8	Headgate Tap						
9	Headgate Metering station	Glenn #3	0.90	SWP, LDSP	21.00	1	1
10	Job Order #74000976						
11							
12	R2 HELM-KERMAN 70KV						
13	T-LINE TP 11/4	TP 9/6	2.00	WP, LDSP	16.00	1	1
14	Job Order #74001043						
15							
16	Cortina #3						
17	Cortina Sub	Wadham Junction	5.50	LDSP, WP, TSP	17.00	1	1
18	Job Order #74001094						
19							
20	Missouri Flat						
21	Gold Hill	Shingle Springs sub	12.20	Lattice, TSP	15.00	2	2
22	Job Order #74001423						
23							
24	ENG~LODI STIG-EIGHT						
25	(T-LINE) Lodi Sting	Eight Mile Road	2.30	Various	6.00	2	2
26	Job Order #74003601						
27							
28	Smartville_ E Nicolaus Inside						
29	BAFB Smartville-Nicolaus	9/183	4.10	LDSP, WP, TSP	18.00	1	1
30	Job Order #74003265						
31							
32	Vaca-Vacaville-Cordelia						
33	Vacaville	Cordelia	25.30	TOWER, TSP	5.00	2	2
34	Job Order #74004611						
35							
36	Vaca-Vacaville-Jameson-Nort						
37	Tower 115 kV NERC Project						
38	Vaca-Vacaville-Jameson						
39	Tower	Vaca-Vacaville Cordelia 115	11.70	Tower/TSP	8.00	2	2
40	Job Order						
41							
42	Sobrante R						
43	Sobrante R #1	Sobrante R #2	0.50	Tower	7.00	2	2
44	TOTAL		125.30		163.00	27	27

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Job Order #74004614						
2							
3	Fulton Junction-Vaca 115kV						
4	NERC Project						
5	Fulton Jct	Vacaville	11.80	Tower	7.00	2	2
6	Job Order #74004616						
7							
8	Madison-Vaca 115kV NERC						
9	Project						
10	Madison	Vacaville	11.80	Tower	7.00	2	2
11	Job Order #74006767						
12							
13	GP Gypsum San						
14	J Tap Remo						
15	San Leandro-Oakland JTap	Domtar #2 Sub.	0.10	TSP	1.00	2	2
16	Job Order #74016660						
17							
18	El Dorado-Missouri						
19	002/020	03/023	0.50	TSP	3.00	2	2
20	Job Order #74010782						
21							
22							
23	REMOVALS						
24	OVERHEAD						
25							
26	Big Bend-Clayton Idle						
27	074/551	86/643	5.98	lattice tower	8.00	2	2
28	Job Order #74000663						
29							
30	Brighton-Grand Island Idle						
31	Removal						
32	24/189	41/307	16.42	lattice tower	7.00	2	2
33	Job Order #74010461						
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		125.30		163.00	27	27

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
Various	AAC	T1 8.5 FT	115		4,773,941	1,267,713		6,041,654	5
									6
									7
									8
4/0	AAC	T1 8.5 FT	60		537,454	344,306		881,760	9
									10
									11
									12
715.5	AAC	Various	70		528,710	1,431,542		1,960,252	13
									14
									15
									16
715.5	AAC	Various	60		989,918	3,400,476		4,390,394	17
									18
									19
									20
795	ACSS	Various	115	4,162,563	25,240,911	20,740,114		50,143,588	21
									22
									23
									24
795	ACSS	16.5' twr	230	165,363	143,117	1,906,788		2,215,268	25
									26
									27
									28
Various	Various	Various	60		1,034,547	978,995		2,013,542	29
									30
									31
									32
Various	Various	A 10 FT	115		505,717	221,294		727,011	33
									34
									35
									36
									37
									38
397	ACSR	Vert10 FT	115		8,657,789	14,925,557		23,583,346	39
									40
									41
									42
397	ACSR	Vert10 FT	115		1,374,811	4,075,738		5,450,549	43
				4,327,926	52,265,210	62,679,557		119,272,693	44

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 Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Line No.
									1
									2
									3
									4
477	ACSS	Vert10 FT	115		4,246,118	4,575,030		8,821,148	5
									6
									7
									8
									9
477	ACSS	Vert10 FT	115		22,652	1,433,086		1,455,738	10
									11
									12
									13
									14
714	AA	Vert10 FT	115			85,178		85,178	15
									16
									17
									18
397.5	ACSR	SS2, DDE	115		724,914	348,679		1,073,593	19
									20
									21
									22
									23
									24
									25
									26
3/0	CU	Removal	115		862,365	3,723,048		4,585,413	27
									28
									29
									30
									31
3/0	CU	Removal	115		2,622,246	3,222,013		5,844,259	32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				4,327,926	52,265,210	62,679,557		119,272,693	44

Schedule Page: 424 Line No.: 5 Column: d

LSDP, TSP, SWP, TOWER

Schedule Page: 424 Line No.: 5 Column: h

266.8, 1113, 397.5

Schedule Page: 424 Line No.: 25 Column: d

Lattice Towers, TSP

Schedule Page: 424 Line No.: 25 Column: j

16.5' twr arm spacing

Schedule Page: 424 Line No.: 29 Column: h

715, 1/0, 397

Schedule Page: 424 Line No.: 29 Column: i

AAC, ACSR, AAC

Schedule Page: 424 Line No.: 33 Column: h

715.5, 3/0, 397.5, 2/0

Schedule Page: 424 Line No.: 33 Column: i

AAC, CU, ACSR, CU

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ARCO SUB, Lost Hills	Transmission	230.00	70.00	13.20
2	ATLANTIC SUB, Roseville	Transmission	230.00	60.00	13.20
3	ATLANTIC SUB, Roseville	Transmission	230.00	115.00	13.20
4	BAIR SUB, Redwood City	Transmission	115.00	60.00	13.20
5	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
6	BORDEN SUB, Madera	Transmission	230.00	70.00	13.20
7	BRIDGEVILLE SUB, Bridgeville	Transmission	115.00	60.00	13.20
8	BRIGHTON SUB, Sacramento	Transmission	230.00	115.00	13.20
9	BUTTE SUB, Chico	Transmission	115.00	60.00	13.20
10	CASCADE SUB, Pine Grove	Transmission	115.00	60.00	13.20
11	CHRISTIE SUB, Hercules	Transmission	115.00	60.00	13.20
12	COBURN SUB, King City	Transmission	230.00	60.00	13.20
13	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	60.00	13.20
14	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	115.00	13.20
15	COOLEY LANDING SUB, Palo Alto	Transmission	115.00	60.00	13.80
16	CORCORAN SUB, Corcoran	Transmission	115.00	70.00	13.20
17	CORTINA SUB, Williams	Transmission	115.00	60.00	13.20
18	CORTINA SUB, Williams	Transmission	230.00	115.00	13.20
19	COTTONWOOD SUB, Cottonwood	Transmission	230.00	60.00	13.20
20	COTTONWOOD SUB, Cottonwood	Transmission	230.00	115.00	13.20
21	DEL MONTE SUB, Monterey	Transmission	115.00	60.00	13.20
22	DIVIDE SUB, Orcutt	Transmission	115.00	70.00	13.20
23	EAGLE ROCK SUB, Geysers	Transmission	115.00	60.00	
24	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	60.00	
25	EASTSHORE SUB, Hayward	Transmission	230.00	115.00	
26	EVERGREEN SUB, San Jose	Transmission	115.00	60.00	13.20
27	FULTON SUB, Fulton	Transmission	115.00	60.00	13.20
28	FULTON SUB, Fulton	Transmission	230.00	115.00	13.20
29	GATES SUB, Huron	Transmission	115.00	70.00	13.20
30	GATES SUB, Huron	Transmission	230.00	115.00	13.20
31	GATES SUB, Huron	Transmission	500.00	230.00	13.20
32	GLENN SUB, Orland	Transmission	230.00	60.00	13.20
33	GOLD HILL SUB, Folsom	Transmission	115.00	60.00	13.20
34	GOLD HILL SUB, Folsom	Transmission	230.00	115.00	13.20
35	GREEN VALLEY SUB, Watsonville	Transmission	115.00	60.00	
36	HELM SUB, San Joaquin	Transmission	230.00	70.00	13.20
37	HENRIETTA SUB, Lamoore	Transmission	230.00	70.00	13.20
38	HENRIETTA SUB, Lamoore	Transmission	230.00	115.00	2.40
39	HERDLYN SUB, Tracy	Transmission	70.00	60.00	2.40
40	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HOPLAND SUB, Hopland	Transmission	115.00	60.00	13.20
2	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
3	IGNACIO SUB, Ignacio	Transmission	115.00	60.00	13.20
4	IGNACIO SUB, Ignacio	Transmission	230.00	115.00	13.20
5	JEFFERSON SUB, Redwood City	Transmission	230.00	60.00	13.20
6	KASSON SUB, Tracy	Transmission	115.00	60.00	13.20
7	KERN PP SUB, Bakersfield	Transmission	115.00	70.00	13.20
8	KERN PP SUB, Bakersfield	Transmission	230.00	115.00	13.20
9	KINGSBURG SUB, Kingsburg	Transmission	115.00	70.00	13.80
10	LAKEVILLE SUB, Petaluma	Transmission	230.00	60.00	13.20
11	LAKEVILLE SUB, Petaluma	Transmission	230.00	115.00	13.20
12	LAS POSITAS SUB, Livermore	Transmission	230.00	60.00	13.20
13	LOCKEFORD SUB, Lockeford	Transmission	230.00	60.00	13.20
14	LOS BANOS SUB, Los Banos	Transmission	230.00	70.00	13.20
15	LOS BANOS SUB, Los Banos	Transmission	500.00	230.00	13.80
16	LOS ESTEROS SUB,	Transmission	230.00	115.00	12.00
17	MANTECA SUB, Manteca	Transmission	115.00	60.00	13.20
18	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
19	MENDOCINO SUB, Redwood Valley	Transmission	115.00	60.00	13.20
20	MENDOTA SUB, Mendota	Transmission	115.00	70.00	12.00
21	MERCED SUB, Merced	Transmission	115.00	70.00	6.60
22	MESA SUB, Nipomo	Transmission	230.00	115.00	13.20
23	METCALF SUB, San Jose	Transmission	500.00	230.00	13.80
24	METCALF SUB, San Jose	Transmission	230.00	115.00	13.20
25	MIDWAY SUB, Buttonwillow	Transmission	230.00	115.00	13.20
26	MIDWAY SUB, Buttonwillow	Transmission	500.00	230.00	13.80
27	MILLBRAE SUB, Millbrae	Transmission	115.00	60.00	13.80
28	MONTA VISTA SUB, Cupertino	Transmission	115.00	60.00	13.20
29	MONTA VISTA SUB, Cupertino	Transmission	230.00	60.00	
30	MONTA VISTA SUB, Cupertino	Transmission	230.00	115.00	13.20
31	MORAGA SUB, Orinda	Transmission	230.00	115.00	13.20
32	MORRO BAY PP SWYD, Morro Bay	Transmission	230.00	115.00	13.20
33	MOSS LANDING PP SUB, Moss Landing	Transmission	230.00	115.00	13.20
34	MOSS LANDING PP SUB, Moss Landing	Transmission	500.00	230.00	13.80
35	NEW KEARNEY SUB, FRESNO	Transmission	230.00	70.00	13.20
36	NEWARK SUB, Fremont	Transmission	115.00	60.00	13.20
37	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
38	ORO LOMA SUB, Dos Palos	Transmission	115.00	70.00	13.20
39	PALERMO SUB, Palermo	Transmission	230.00	60.00	
40	PALERMO SUB, Palermo	Transmission	230.00	115.00	13.20

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.
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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	PANOCHE SUB, Mendota	Transmission	230.00	115.00	13.20
2	PEASE SUB, Tierra Buena	Transmission	115.00	60.00	13.20
3	PITTSBURG PP SUB,	Transmission	230.00	115.00	13.20
4	PLACER SUB, Auburn	Transmission	115.00	60.00	
5	RAVENSWOOD SUB, Menlo Park	Transmission	230.00	115.00	13.20
6	REEDLEY SUB, Reedley	Transmission	115.00	70.00	13.20
7	RIO OSO SUB, Rio Oso	Transmission	230.00	115.00	13.20
8	ROUND MOUNTAIN SUB, Rd Mtn	Transmission	500.00	230.00	13.80
9	SALADO SUB, Patterson	Transmission	115.00	60.00	13.20
10	SALINAS SUB, Salinas	Transmission	115.00	60.00	13.20
11	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	230.00	115.00	13.20
12	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	60.00	
13	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	230.00	115.00	
14	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	70.00	13.20
15	SAN MATEO SUB, San Mateo	Transmission	115.00	60.00	
16	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
17	SAN RAMON SUB, San Ramon	Transmission	230.00	60.00	13.20
18	SANGER SUB, Fresno	Transmission	115.00	70.00	6.60
19	SCHINDLER SUB, Five Points	Transmission	115.00	70.00	13.20
20	SEMITROPIC SUB, Wasco	Transmission	115.00	70.00	13.80
21	SOBRANTE SUB, Orinda	Transmission	230.00	115.00	
22	SOLEDAD SUB, Soledad	Transmission	115.00	60.00	
23	STAGG SUB, Stockton	Transmission	230.00	60.00	13.20
24	TABLE MOUNTAIN SUB, Oroville	Transmission	230.00	115.00	
25	TABLE MOUNTAIN SUB, Oroville	Transmission	500.00	230.00	13.80
26	TAFT SUB, Taft	Transmission	115.00	70.00	13.20
27	TEMPLETON SUB, TEMPLETON	Transmission	230.00	70.00	13.20
28	TESLA SUB, Tracy	Transmission	230.00	115.00	13.20
29	TESLA SUB, Tracy	Transmission	500.00	230.00	13.20
30	TRINITY SUB, Weaverville	Transmission	115.00	60.00	13.20
31	TULUCAY SUB, Napa	Transmission	230.00	60.00	13.20
32	VACA DIXON SUB, Vacaville	Transmission	115.00	60.00	13.20
33	VACA DIXON SUB, Vacaville	Transmission	230.00	115.00	13.20
34	VACA DIXON SUB, Vacaville	Transmission	500.00	230.00	13.80
35	VALLEY SPRINGS SUB, Valley Springs	Transmission	230.00	60.00	13.20
36	WEBER SUB, Stockton	Transmission	230.00	60.00	13.20
37	WHEELER RIDGE SUB, Bakersfield	Transmission	115.00	70.00	13.20
38	WHEELER RIDGE SUB, Bakersfield	Transmission	230.00	70.00	13.20
39	WILSON SUB, Merced	Transmission	230.00	115.00	13.20
40	7th STANDARD SUB, Bakersfield	Distribution	115.00	21.00	

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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	AIRWAYS SUB, Fresno, Ca.	Distribution	115.00	12.00	7.20
2	ALHAMBRA SUB, Martinez	Distribution	115.00	12.00	7.20
3	ALLEGHANY SUB, Alleghany	Distribution	60.00	12.00	7.20
4	ALMADEN SUB, San Jose	Distribution	60.00	12.00	7.20
5	ALPAUGH SUB, Tulare	Distribution	115.00	12.00	
6	ALTO SUB, Mill Valley	Distribution	60.00	12.00	2.40
7	AMES DISTRIBUTION SUB, Mountain View	Distribution	115.00	12.00	7.20
8	ANDERSON SUB, Anderson	Distribution	60.00	12.00	2.40
9	ANGIOLA SUB, Kings	Distribution	70.00	12.00	7.20
10	ANITA SUB, Chico	Distribution	60.00	12.00	2.40
11	ANTELOPE SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
12	ANTLER SUB, Lakehead	Distribution	60.00	12.00	2.40
13	APPLE HILL SUB, Camino	Distribution	115.00	12.00	7.20
14	APPLE HILL SUB, Camino	Distribution	115.00	21.00	7.20
15	ARBUCKLE SUB, ARBUCKLE	Distribution	60.00	12.00	7.20
16	ARCATA SUB, Arcata	Distribution	60.00	12.00	2.40
17	ARVIN SUB, Arvin	Distribution	70.00	12.00	2.40
18	ASHLAN AVENUE SUB, Fresno	Distribution	230.00	12.00	7.20
19	ATASCADERO SUB, Atascadero	Distribution	115.00	12.00	7.20
20	ATWATER SUB, Atwater	Distribution	115.00	12.00	7.20
21	AUBERRY SUB, Auberry	Distribution	70.00	12.00	7.20
22	AVENA SUB, Escalon	Distribution	115.00	12.00	
23	AVENAL SUB, Avenal	Distribution	70.00	12.00	
24	BAHIA SUB, Benicia	Distribution	230.00	12.00	7.20
25	BAIR SUB, Redwood City	Transmission	115.00	12.00	7.20
26	BAKERSFIELD SUB, Bakersfield	Distribution	230.00	21.00	7.20
27	BANGOR SUB, Bangor	Distribution	60.00	12.00	7.20
28	BARTON SUB, Fresno	Distribution	115.00	12.00	7.20
29	BASALT SUB, Napa	Distribution	60.00	12.00	2.40
30	BAY MEADOWS SUB, San Mateo	Distribution	115.00	21.00	7.20
31	BAY MEADOWS SUB, San Mateo	Distribution	115.00	12.00	7.20
32	BAYWOOD SUB, Morro Bay	Distribution	70.00	12.00	2.40
33	BEAR VALLEY SUB, Bear Valley	Distribution	70.00	21.00	7.20
34	BELL SUB, Auburn	Distribution	115.00	12.00	7.20
35	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	12.00	2.40
36	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	4.00	2.40
37	BELLEVUE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
38	BELMONT SUB, Belmont	Distribution	115.00	12.00	7.20
39	BERRENDA A SUB,	Distribution	70.00	4.00	2.40
40	BIG BASIN SUB, Santa Cruz	Distribution	60.00	12.00	

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SUBSTATIONS

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1	BIG MEADOWS SUB, Greenville	Distribution	60.00	44.00	2.40
2	BIOLA SUB, Biola	Distribution	70.00	12.00	2.40
3	BLACKWELL SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
4	BLUE LAKE SUB, Blue Lake	Distribution	60.00	12.00	2.40
5	BOGUE SUB, Yuba City	Distribution	115.00	12.00	7.20
6	BOLINAS SUB, Boninas	Distribution	60.00	12.00	7.20
7	BONITA SUB, Madera	Distribution	70.00	12.00	7.20
8	BORDEN SUB, Madera	Transmission	230.00	12.00	7.20
9	BOWLES SUB, Bowles	Distribution	70.00	12.00	7.20
10	BRENTWOOD SUB, Brentwood	Distribution	230.00	21.00	7.20
11	BRITTON SUB, Sunnyvale	Distribution	115.00	12.00	
12	BRUNSWICK SUB, Grass Valley	Distribution	115.00	12.00	7.20
13	BUELLTON SUB, Buellton /93427	Distribution	115.00	12.00	7.20
14	BUENA VISTA SUB, Salinas	Distribution	60.00	12.00	7.20
15	BULLARD SUB, Fresno	Distribution	115.00	12.00	7.20
16	BULLARD SUB, Fresno	Distribution	115.00	21.00	7.20
17	BURLINGAME SUB, Burlingame	Distribution	115.00	21.00	7.20
18	BUTTE SUB, Chico	Transmission	115.00	12.00	7.20
19	CABRILLO SUB, LOMPOC	Distribution	115.00	12.00	7.20
20	CADET SUB, Maricopa	Distribution	70.00	12.00	
21	CAL WATER SUB,	Distribution	115.00	12.00	7.20
22	CALAVERAS CEMENT SUB, San Andreas	Distribution	60.00	12.00	7.20
23	CALFLAX SUB, Huron	Distribution	70.00	12.00	2.40
24	CALIFORNIA AVE SUB, Fresno	Distribution	115.00	12.00	7.20
25	CALISTOGA SUB, Calistoga	Distribution	60.00	12.00	7.20
26	CALPELLA SUB, Calpella	Distribution	115.00	12.00	7.20
27	CAMDEN SUB, Riverdale	Distribution	70.00	12.00	2.40
28	CAMP EVERS SUB, Santa Cruz	Distribution	115.00	21.00	7.20
29	CAMPHORA SUB, Monterey	Distribution	60.00	12.00	7.20
30	CAMPHORA SUB, Monterey	Distribution	60.00	4.00	
31	CANAL SUB, Los Banos	Distribution	70.00	12.00	7.20
32	CANTUA SUB, Cantua Creek	Distribution	115.00	12.00	
33	CAPAY SUB, Orland	Distribution	60.00	12.00	2.40
34	CARBONA SUB, Tracy	Distribution	60.00	12.00	7.20
35	CARNATION SUB, Bakersfield	Distribution	70.00	21.00	7.20
36	CARNERAS SUB, Blackwells Corner	Distribution	70.00	12.00	7.20
37	CAROLANDS SUB, Hillsborough	Distribution	60.00	4.00	
38	CARQUINEZ SUB, Vallejo	Distribution	115.00	12.00	2.40
39	CARUTHERS SUB, Fresno	Distribution	70.00	12.00	2.40
40	CASSIDY SUB, Madera	Distribution	70.00	12.00	2.40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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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	CASTRO VALLEY SUB, Castro Valley	Distribution	230.00	12.00	
2	CASTROVILLE SUB, Castroville	Distribution	115.00	21.00	7.20
3	CATLETT SUB, Pleasant Grove	Distribution	60.00	12.00	
4	CAWELO B SUB, Famosa	Distribution	70.00	4.00	
5	CAYETANO SUB, Danville	Distribution	230.00	21.00	7.20
6	CAYUCOS SUB, Cayucos	Distribution	70.00	12.00	7.20
7	CHANNEL SUB, Stockton	Distribution	60.00	12.00	
8	CHARCA SUB, Wasco	Distribution	115.00	12.00	7.20
9	CHEROKEE SUB, Stockton	Distribution	60.00	12.00	7.20
10	CHICO A SUB, Chico	Distribution	60.00	12.00	7.20
11	CHICO B SUB, Chico	Distribution	115.00	12.00	7.20
12	CHOLAME SUB, Cholame/93431	Distribution	70.00	12.00	2.40
13	CHOLAME SUB, Cholame/93431	Distribution	70.00	21.00	2.40
14	CHOWCHILLA SUB, Chowchilla	Distribution	115.00	12.00	7.20
15	CLARK ROAD SUB, Paradise	Distribution	60.00	12.00	2.40
16	CLARKSVILLE SUB, Clarksville	Distribution	115.00	21.00	7.20
17	CLAY SUB, Ione	Distribution	60.00	12.00	2.40
18	CLAYTON SUB, Concord	Distribution	115.00	21.00	7.20
19	CLAYTON SUB, Concord	Distribution	115.00	12.00	7.20
20	CLEAR LAKE SUB, Finley	Distribution	60.00	12.00	2.40
21	CLOVERDALE SUB, Cloverdale	Distribution	115.00	12.00	7.20
22	CLOVIS SUB, Clovis	Distribution	115.00	12.00	7.20
23	CLOVIS SUB, Clovis	Distribution	115.00	21.00	7.20
24	COALINGA #1 SUB, Coalinga	Distribution	70.00	12.00	7.20
25	COALINGA #2 SUB, Coalinga	Distribution	70.00	12.00	2.40
26	COARSEGOLD SUB, Coursegold	Distribution	115.00	21.00	7.20
27	COLUMBUS SUB, Bakersfield	Distribution	115.00	12.00	7.20
28	COLUSA JUNCT SUB, Colusa	Distribution	60.00	12.00	7.20
29	COLUSA SUB, Colusa	Distribution	60.00	12.00	
30	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	21.00	7.20
31	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	21.00	6.60
32	COPPERMINE SUB, Clovis	Distribution	70.00	12.00	2.40
33	COPUS SUB, Bakersfield	Distribution	70.00	12.00	
34	CORCORAN SUB, Corcoran	Transmission	115.00	12.00	7.20
35	CORDELIA SUB, Cordelia	Distribution	115.00	12.00	7.20
36	CORDELIA SUB, Cordelia	Distribution	60.00	12.00	2.40
37	CORNING SUB, Corning	Distribution	60.00	12.00	2.40
38	CORONA SUB,	Distribution	115.00	12.00	7.20
39	CORRAL SUB, Bellota	Distribution	60.00	12.00	7.20
40	CORTINA SUB, Williams	Transmission	115.00	12.00	7.20

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1	COTATI SUB, Cotati	Distribution	60.00	12.00	
2	COTTLE SUB, Oakdale	Distribution	230.00	17.00	
3	COTTONWOOD SUB, Cottonwood	Transmission	115.00	12.00	7.20
4	COUNTRY CLUB SUB, Stockton	Distribution	60.00	12.00	
5	COUNTRY CLUB SUB, Stockton	Distribution	60.00	4.00	
6	CRESSEY SUB, Merced	Distribution	115.00	21.00	
7	CURTIS SUB, Sonora	Distribution	115.00	18.00	
8	CUYAMA SUB, Cuyama	Distribution	70.00	12.00	
9	CUYAMA SUB, Cuyama	Distribution	70.00	21.00	7.20
10	CYMRIC SUB, McKitrick	Distribution	115.00	12.00	7.20
11	DAIRYLAND SUB, Chowchilla	Distribution	115.00	12.00	7.20
12	DALY CITY SUB, Daly City	Distribution	115.00	12.00	7.20
13	DAVIS SUB, Davis	Distribution	115.00	12.00	7.20
14	DEEPWATER SUB, W. Sacramento	Distribution	115.00	12.00	7.20
15	DEL MAR SUB, Rocklin	Distribution	60.00	21.00	7.20
16	DEL MAR SUB, Rocklin	Distribution	60.00	12.00	7.20
17	DEL MONTE SUB, Monterey	Transmission	115.00	21.00	7.20
18	DERRICK SUB, Kettleman	Distribution	70.00	12.00	2.40
19	DESCHUTES SUB, Palo Cedro	Distribution	60.00	12.00	7.20
20	DIAMOND SPRINGS SUB, Placerville	Distribution	115.00	12.00	7.20
21	DINUBA SUB, Dinuba	Distribution	70.00	12.00	7.20
22	DIVIDE SUB, Orcutt	Transmission	70.00	12.00	2.40
23	DIVIDE SUB, Orcutt	Transmission	115.00	12.00	7.20
24	DIXON LANDING SUB,	Distribution	115.00	21.00	7.20
25	DIXON SUB, Dixon	Distribution	60.00	12.00	
26	DOLAN ROAD SUB, Moss Landing	Distribution	115.00	12.00	
27	DOS PALOS SUB, Dos Palos	Distribution	70.00	12.00	7.20
28	DUMBARTON SUB, Fremont	Distribution	115.00	12.00	
29	DUNBAR SUB, Glen Ellen	Distribution	60.00	12.00	
30	EAST GRAND SUB, So San Fran.	Distribution	115.00	12.00	7.20
31	EAST MARYSVILLE SUB, Marysville,	Distribution	115.00	12.00	7.20
32	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	12.00	
33	EAST STOCKTON SUB, Stockton	Distribution	60.00	12.00	7.20
34	EAST STOCKTON SUB, Stockton	Distribution	60.00	4.00	
35	EDENVALE SUB, San Jose	Distribution	115.00	21.00	7.20
36	EDENVALE SUB, San Jose	Distribution	115.00	12.00	7.20
37	EDES SUB, Oakland	Distribution	115.00	12.00	7.20
38	EEL RIVER SUB, Ferndale	Distribution	60.00	12.00	7.20
39	EIGHT MILE SUB, Stockton	Distribution	230.00	21.00	7.20
40	EL CAPITAN SUB, Snelling	Distribution	115.00	12.00	

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1	EL CAPITAN SUB, Snelling	Distribution	115.00	21.00	
2	EL CERRITO G SUB, El Cerrito	Distribution	115.00	12.00	
3	EL NIDO SUB, Merced	Distribution	115.00	12.00	7.20
4	EL PATIO SUB, Campbell	Distribution	115.00	12.00	7.20
5	EL PECO SUB, Madera	Distribution	70.00	12.00	
6	ELECTRA SUB,	Distribution	60.00	12.00	
7	ELK HILLS SUB, Valley Acres	Distribution	70.00	12.00	
8	ELK SUB, Elk	Distribution	60.00	12.00	2.40
9	EUREKA A SUB, Eureka	Distribution	60.00	12.00	7.20
10	EUREKA E SUB, Eureka	Distribution	60.00	12.00	
11	EVERGREEN SUB, San Jose	Transmission	115.00	21.00	7.20
12	FAIRHAVEN SUB, Fairhaven	Distribution	60.00	12.00	7.20
13	FAIRVIEW SUB, Martinez	Distribution	115.00	21.00	12.00
14	FAIRWAY SUB, Santa Maria	Distribution	115.00	12.00	7.20
15	FAMOSO SUB, Famosa	Distribution	115.00	12.00	
16	FELLOWS SUB, Fellows	Distribution	115.00	21.00	
17	FIGARDEN SUB, Fresno	Distribution	230.00	21.00	7.20
18	FIREBAUGH SUB, Firebaugh	Distribution	70.00	12.00	7.20
19	FITCH MOUNTAIN SUB, Healdsburg	Distribution	60.00	12.00	7.20
20	FLINT SUB, Auburn	Distribution	115.00	12.00	7.20
21	FMC SUB, San Jose	Distribution	115.00	12.00	7.20
22	FOOTHILL SUB, SLO	Distribution	115.00	12.00	2.40
23	FORESTHILL SUB, Foresthill,	Distribution	60.00	12.00	7.20
24	FORT BRAGG A SUB, Fort Bragg	Distribution	60.00	12.00	
25	FORT ORD SUB, Fort Ord	Distribution	60.00	21.00	7.20
26	FORT ORD SUB, Fort Ord	Distribution	60.00	12.00	2.40
27	FRANKLIN SUB, Hercules	Distribution	60.00	12.00	7.20
28	FREMONT SUB, Fremont	Distribution	115.00	12.00	7.20
29	FRENCH CAMP SUB, Stockton	Distribution	60.00	12.00	
30	FROGTOWN SUB, Angels Camp	Distribution	115.00	17.00	
31	FRUITVALE SUB, Bakersfield	Distribution	70.00	12.00	2.40
32	FULTON SUB, Fulton	Transmission	230.00	12.00	7.20
33	GABILAN SUB, Salinas	Distribution	115.00	12.00	7.20
34	GALLO SUB, Livingston	Distribution	115.00	12.00	
35	GANSNER SUB, Quincy	Distribution	60.00	12.00	7.20
36	GANSO SUB, Buttonwillow	Distribution	115.00	12.00	7.20
37	GARBERVILLE SUB, Garberville	Distribution	60.00	12.00	7.20
38	GATES SUB, Huron	Transmission	230.00	12.00	7.20
39	GATES SUB, Huron	Transmission	115.00	12.00	
40	GEYSERVILLE SUB, Geyserville	Distribution	60.00	12.00	2.40

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GIFFEN SUB, San Joaquin	Distribution	70.00	12.00	2.40
2	GIRVAN SUB, Redding	Distribution	60.00	12.00	7.20
3	GLENN SUB, Orland	Transmission	60.00	12.00	
4	GLENWOOD SUB, Menlo Park	Distribution	60.00	12.00	7.20
5	GLENWOOD SUB, Menlo Park	Distribution	60.00	4.00	
6	GOLDTREE SUB, SLO	Distribution	115.00	12.00	7.20
7	GONZALES SUB, Gonzales	Distribution	60.00	12.00	
8	GOOSE LAKE SUB, Wasco	Distribution	115.00	12.00	7.20
9	GRAND ISLAND SUB, Ryde	Distribution	115.00	21.00	7.20
10	GRANT SUB, San Lorenzo	Distribution	115.00	12.00	7.20
11	GRASS VALLEY SUB, Grass Valley	Distribution	60.00	12.00	
12	GREEN VALLEY SUB, Watsonville	Transmission	115.00	21.00	7.20
13	GREENBRAE SUB, Larkspur	Distribution	60.00	12.00	7.20
14	GUALALA SUB, Gualala	Distribution	60.00	12.00	2.40
15	GUERNSEY SUB, Hanford	Distribution	70.00	12.00	
16	GUSTINE SUB, Gustine	Distribution	60.00	12.00	7.20
17	HALF MOON BAY SUB, Half Moon Bay	Distribution	60.00	12.00	2.40
18	HAMMER SUB, Stockton	Distribution	60.00	12.00	7.20
19	HAMMONDS SUB, Fresno	Distribution	115.00	12.00	
20	HARDING SUB, Stockton	Distribution	60.00	4.00	
21	HARDWICK SUB, Layton	Distribution	70.00	12.00	7.20
22	HARRIS SUB, Eureka	Distribution	60.00	12.00	7.20
23	HARTER SUB, Yuba City	Distribution	60.00	12.00	7.20
24	HARTLEY SUB, Lakeport	Distribution	60.00	12.00	7.20
25	HATTON SUB, Carmel Valley	Distribution	60.00	12.00	2.40
26	HENRIETTA SUB, Lemoore	Transmission	70.00	12.00	2.40
27	HERDLYN SUB, Tracy	Transmission	60.00	12.00	2.40
28	HICKS SUB, San Jose	Distribution	230.00	21.00	7.20
29	HICKS SUB, San Jose	Distribution	230.00	12.00	7.20
30	HIGGINS SUB, Higgins Corner	Distribution	115.00	12.00	7.20
31	HIGHLANDS SUB, Clear Lake	Distribution	115.00	12.00	7.20
32	HIGHWAY SUB, Petaluma	Distribution	115.00	12.00	7.20
33	HOLLISTER SUB, Hollister	Distribution	115.00	21.00	7.20
34	HOLLISTER SUB, Hollister	Distribution	60.00	21.00	
35	HONCUT SUB, Honcut	Distribution	115.00	12.00	7.20
36	HOPLAND SUB, Hopland	Transmission	60.00	12.00	2.40
37	HORSESHOE SUB, Granite Bay	Distribution	115.00	12.00	7.20
38	HOWLAND ROAD SUB, Manteca	Distribution	115.00	12.00	7.20
39	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	13.80	
40	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	13.80	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

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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	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	12.00	7.20
2	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	2.00	
3	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	2.00	
4	HURON SUB, Huron	Distribution	70.00	12.00	2.40
5	IGNACIO SUB, Ignacio	Transmission	115.00	12.00	
6	IMHOFF SUB, Martinez	Distribution	115.00	12.00	7.20
7	IONE SUB, Ione	Distribution	60.00	12.00	7.20
8	JACINTO SUB, Willows	Distribution	60.00	12.00	7.20
9	JACOBS CORNER SUB, Lemoore	Distribution	70.00	12.00	2.40
10	JAMESON SUB, CORDELIA	Distribution	115.00	12.00	7.20
11	JANES CREEK SUB, Arcata	Distribution	60.00	12.00	7.20
12	JARVIS SUB, Union City	Distribution	115.00	12.00	7.20
13	JESSUP SUB, Anderson	Distribution	115.00	12.00	
14	JOLON SUB, King City	Distribution	60.00	12.00	
15	KELSO SUB, Tracy	Distribution	230.00	12.00	
16	KERMAN SUB, Kerman	Distribution	70.00	12.00	7.20
17	KERN OIL SUB, Bakersfield	Distribution	115.00	12.00	7.20
18	KERN PP DIST SUB, Bakersfield	Distribution	115.00	21.00	7.20
19	KESWICK SUB, Keswick	Distribution	60.00	12.00	2.40
20	KETTLEMAN HILLS SUB, Kettleman	Distribution	70.00	12.00	2.40
21	KING CITY SUB, King City	Distribution	60.00	12.00	
22	KINGSBURG SUB, Kingsburg	Transmission	115.00	12.00	7.20
23	KIRKER SUB, Pittsburg	Distribution	115.00	21.00	7.20
24	KONOCTI SUB, Clear Lake	Distribution	60.00	12.00	2.40
25	LAKEVIEW SUB, Bakersfield	Distribution	70.00	12.00	2.40
26	LAKEVILLE SUB, Petaluma	Transmission	115.00	12.00	7.20
27	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	21.00	7.20
28	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	12.00	7.20
29	LAMMERS SUB, TRACY	Distribution	115.00	12.00	7.20
30	LAMONT SUB, Bakersfield	Distribution	115.00	12.00	
31	LAS GALLINAS A SUB, Las Gallinas	Distribution	115.00	12.00	7.20
32	LAS PALMAS SUB, Fresno	Distribution	115.00	12.00	7.20
33	LAS POSITAS SUB, Livermore	Transmission	230.00	21.00	7.20
34	LAS PULGAS SUB, Redwood City	Distribution	60.00	4.00	2.40
35	LAWRENCE SUB, Sunnyvale	Distribution	115.00	12.00	7.20
36	LE GRAND SUB, Le Grand	Distribution	115.00	12.00	7.20
37	LEMOORE SUB, Armonia	Distribution	70.00	12.00	2.40
38	LERDO SUB, Bakersfield	Distribution	115.00	12.00	7.20
39	LINCOLN SUB, Lincoln	Distribution	115.00	12.00	7.20
40	LINDEN SUB, Linden	Distribution	60.00	12.00	2.40

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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	LIVE OAK SUB, Live Oak	Distribution	60.00	12.00	
2	LIVERMORE SUB, Livermore	Distribution	60.00	12.00	2.40
3	LIVINGSTON SUB, Livingston	Distribution	115.00	12.00	7.20
4	LIVINGSTON SUB, Livingston	Distribution	70.00	12.00	
5	LLAGAS SUB, Gilroy	Distribution	115.00	21.00	12.00
6	LOCKEFORD SUB, Lockeford	Transmission	115.00	21.00	7.20
7	LOCKHEED #1 SUB, Sunnyvale	Distribution	115.00	12.00	7.20
8	LOCKHEED #2 SUB, Sunnyvale	Distribution	115.00	12.00	
9	LODI SUB, Lodi	Distribution	60.00	12.00	2.40
10	LODI SUB, Lodi	Distribution	60.00	4.00	
11	LOGAN CREEK SUB, Willows	Distribution	230.00	21.00	
12	LONETREE SUB, Antioch	Distribution	230.00	21.00	7.20
13	LOS ALTOS SUB, Los Altos	Distribution	60.00	12.00	
14	LOS COCHES SUB, Greenfield	Distribution	60.00	12.00	
15	LOS GATOS SUB, Los Gatos	Distribution	60.00	12.00	7.20
16	LOS MOLINOS SUB, Los Molinos	Distribution	60.00	12.00	7.20
17	LOS OSITOS SUB, Monterey	Distribution	60.00	21.00	7.20
18	LOYOLA SUB, Loyola	Distribution	60.00	12.00	7.20
19	LOYOLA SUB, Loyola	Distribution	60.00	4.00	2.40
20	LUCERNE SUB, Lucerne	Distribution	115.00	12.00	7.20
21	MABURY SUB, San Jose	Distribution	60.00	12.00	2.40
22	MABURY SUB, San Jose	Distribution	60.00	12.00	7.20
23	MADERA SUB, Madera	Distribution	70.00	12.00	
24	MADISON SUB, Madison	Distribution	60.00	12.00	7.20
25	MADISON SUB, Madison	Distribution	115.00	12.00	
26	MAGUNDEN SUB, Bakersfield	Distribution	115.00	12.00	7.20
27	MAGUNDEN SUB, Bakersfield	Distribution	115.00	21.00	7.20
28	MALAGA SUB, Fresno	Distribution	115.00	12.00	7.20
29	MANCHESTER SUB, Fresno	Distribution	115.00	12.00	7.20
30	MANTECA SUB, Manteca	Transmission	115.00	17.00	
31	MARICOPA SUB, Maricopa	Distribution	70.00	12.00	2.40
32	MARIPOSA SUB, Mariposa	Distribution	70.00	21.00	
33	MARTELL SUB, Martell	Distribution	60.00	12.00	2.40
34	MARYSVILLE SUB, Marysville	Distribution	60.00	12.00	
35	MAXWELL SUB, Maxwell	Distribution	60.00	12.00	
36	MCARTHUR SUB, McArthur	Distribution	60.00	12.00	2.40
37	MCCALL SUB, Selma	Transmission	115.00	12.00	7.20
38	MCDONALD-MCDONALDISLAND SUB, Stockton	Distribution	60.00	4.00	2.40
39	MCFARLAND SUB, McFarland	Distribution	70.00	12.00	7.20
40	MCKEE SUB, San Jose	Distribution	115.00	12.00	7.20

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1	MCKITTRICK SUB, MCKITTRICK	Distribution	70.00	12.00	
2	MCMULLIN SUB, Fresno	Distribution	230.00	12.00	7.20
3	MEADOW LANE SUB, Concord	Distribution	115.00	21.00	7.20
4	MENDOCINO SUB, Redwood Valley	Transmission	60.00	12.00	2.40
5	MENDOTA SUB, Mendota	Transmission	115.00	12.00	7.20
6	MENLO SUB, Menlo Park	Distribution	60.00	12.00	7.20
7	MENLO SUB, Menlo Park	Distribution	60.00	4.00	
8	MERCED SUB, Merced	Transmission	115.00	12.00	7.20
9	MERCED SUB, Merced	Transmission	115.00	21.00	7.20
10	MERIDIAN SUB, Meridian	Distribution	60.00	12.00	
11	MESA SUB, Nipomo	Transmission	230.00	12.00	
12	METTLER SUB, Stockton	Distribution	60.00	12.00	
13	MIDDLETOWN SUB, Middletown	Distribution	60.00	12.00	7.20
14	MIDWAY SUB, Buttonwillow	Transmission	115.00	12.00	7.20
15	MILLBRAE SUB, Millbrae	Transmission	115.00	12.00	
16	MILLBRAE SUB, Millbrae	Transmission	60.00	4.00	
17	MILPITAS SUB, Milpitas	Distribution	115.00	21.00	7.20
18	MILPITAS SUB, Milpitas	Distribution	115.00	12.00	7.20
19	MIRABEL SUB, Forestville	Distribution	60.00	12.00	
20	MI-WUK SUB, Sugarpine	Distribution	115.00	17.00	
21	MOLINO SUB, Sebastopol	Distribution	60.00	12.00	7.20
22	MONROE SUB, Santa Rosa	Distribution	115.00	21.00	7.20
23	MONROE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
24	MONTAGUE SUB, San Jose	Distribution	115.00	21.00	7.20
25	MONTE RIO SUB, Monte Rio	Distribution	60.00	12.00	7.20
26	MONTEREY SUB, Monterey	Distribution	60.00	4.00	
27	MORAGA SUB, Orinda	Transmission	115.00	12.00	
28	MORGAN HILL SUB, Morgan Hill	Distribution	115.00	21.00	7.20
29	MORMON SUB, Stockton	Distribution	60.00	12.00	7.20
30	MORRO BAY PP SWYD, Morro Bay	Transmission	115.00	12.00	7.20
31	MOSHER SUB, Stockton	Distribution	60.00	21.00	7.20
32	MOUNTAIN VIEW SUB, Mt. View	Distribution	115.00	12.00	7.20
33	MT. EDEN SUB, Hayward	Distribution	115.00	12.00	7.20
34	MT. QUARRIES SUB, Cool	Distribution	60.00	12.00	7.20
35	NAPA SUB, Napa	Distribution	60.00	12.00	
36	NARROWS SUB,	Distribution	60.00	21.00	7.20
37	NEWARK DIST SUB, Fremont	Distribution	230.00	21.00	7.20
38	NEWARK SUB, Fremont	Transmission	115.00	12.00	7.20
39	NEWBURG SUB, Fortuna	Distribution	60.00	12.00	2.40
40	NEWHALL SUB, Firebaugh	Distribution	115.00	12.00	7.20

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1	NEWMAN SUB, Newman	Distribution	60.00	12.00	7.20
2	NORCO SUB, Bakersfield	Distribution	115.00	12.00	7.20
3	NORD SUB, Chico	Distribution	115.00	12.00	7.20
4	NORTECH SUB, San Jose	Distribution	115.00	21.00	7.20
5	NORTH DUBLIN SUB, Pleasanton	Distribution	230.00	21.00	12.00
6	NORTH TOWER SUB, Vallejo	Distribution	115.00	12.00	7.20
7	NOTRE DAME SUB, Chico	Distribution	115.00	12.00	7.20
8	NOVATO SUB, Novato	Distribution	60.00	12.00	7.20
9	OAKHURST SUB, Oakhurst	Distribution	115.00	12.00	2.40
10	OAKLAND C (OAKLAND PP) SUB, Oakland	Distribution	115.00	12.00	7.20
11	OAKLAND D SUB, Oakland	Distribution	115.00	12.00	7.20
12	OAKLAND J SUB, Oakland	Distribution	115.00	12.00	7.20
13	OAKLAND K (CLAREMONT) SUB, Oakland	Distribution	115.00	12.00	6.60
14	OAKLAND L SUB, Oakland	Distribution	115.00	12.00	7.20
15	OAKLAND X SUB, Oakland	Distribution	115.00	12.00	7.20
16	OCEANO SUB, Oceano	Distribution	115.00	12.00	7.20
17	OILFIELDS SUB, San Ardo	Distribution	60.00	12.00	
18	OLD KEARNEY SUB, Fresno	Distribution	70.00	12.00	13.20
19	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	2.40
20	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	7.20
21	OLETA SUB, Plymouth	Distribution	60.00	12.00	2.40
22	OLIVEHURST SUB, Olivehurst	Distribution	115.00	12.00	7.20
23	OREGON TRAIL SUB, Redding	Distribution	115.00	12.00	7.20
24	OREGON TRAIL SUB, Redding	Distribution	60.00	12.00	2.40
25	ORLAND B SUB, Orland	Distribution	60.00	12.00	2.40
26	ORO FINO SUB, Magalia	Distribution	60.00	12.00	2.40
27	ORO LOMA SUB, Dos Palos	Transmission	70.00	12.00	2.40
28	ORO LOMA SUB, Dos Palos	Transmission	115.00	12.00	
29	OROSI SUB, Orosi	Distribution	70.00	12.00	7.20
30	OROVILLE SUB, Oroville	Distribution	60.00	12.00	7.20
31	OROVILLE SUB, Oroville	Distribution	60.00	4.00	2.40
32	ORTIGA SUB, Los Banos	Distribution	70.00	12.00	2.40
33	PACIFICA SUB, Pacifica	Distribution	60.00	12.00	
34	PALMER SUB, Sisquat	Distribution	115.00	12.00	7.20
35	PANAMA SUB, Bakersfield	Distribution	70.00	21.00	7.20
36	PANOCHE SUB, Mendota	Transmission	230.00	12.00	7.20
37	PANORAMA SUB, Anderson	Distribution	115.00	12.00	
38	PARADISE SUB, Paradise	Distribution	60.00	12.00	7.20
39	PARADISE SUB, Paradise	Distribution	115.00	12.00	
40	PARKWAY SUB, Vallejo	Distribution	230.00	12.00	7.20

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1	PARLIER SUB, Parlier	Distribution	115.00	12.00	7.20
2	PASO ROBLES SUB, Paso Robles	Distribution	70.00	12.00	2.40
3	PAUL SWEET SUB, Santa Cruz	Distribution	115.00	21.00	7.20
4	PEABODY SUB, Fairfield	Distribution	230.00	21.00	7.20
5	PEACHTON SUB, Gridley	Distribution	60.00	12.00	2.40
6	PEASE SUB, Tierra Buena	Transmission	115.00	12.00	
7	PENNGROVE SUB, Penngrove	Distribution	115.00	12.00	
8	PENRYN SUB, Penryn	Distribution	60.00	12.00	7.20
9	PEORIA SUB, Jamestown	Distribution	115.00	18.00	
10	PETALUMA C SUB, Petaluma	Distribution	60.00	12.00	
11	PIERCY SUB, San Jose	Distribution	115.00	21.00	7.20
12	PINE GROVE SUB, Pine Grove	Distribution	60.00	12.00	2.40
13	PINEDALE SUB, FRESNO	Distribution	115.00	21.00	7.20
14	PLACER SUB, Auburn	Transmission	115.00	12.00	
15	PLACERVILLE SUB, Placerville	Distribution	115.00	12.00	7.20
16	PLACERVILLE SUB, Placerville	Distribution	115.00	21.00	
17	PLAINFIELD SUB, Davis	Distribution	60.00	12.00	2.40
18	PLEASANT GROVE SUB, Pleasant Grove	Distribution	60.00	21.00	7.20
19	PLUMAS SUB, Wheatland	Distribution	60.00	21.00	7.20
20	PLUMAS SUB, Wheatland	Distribution	60.00	12.00	7.20
21	POINT MORETTI SUB, Davenport	Distribution	60.00	12.00	2.40
22	POINT PINOLE SUB, Richmond	Distribution	115.00	12.00	6.60
23	POSO MOUNTAIN SUB, Kern	Distribution	115.00	21.00	
24	PRUNEDALE SUB, Prunedale	Distribution	115.00	12.00	7.20
25	PUEBLO SUB, Napa	Distribution	115.00	12.00	
26	PUEBLO SUB, Napa	Distribution	115.00	21.00	
27	PURISIMA SUB, Lompoc	Distribution	115.00	12.00	7.20
28	PUTAH CREEK SUB, Winters	Distribution	115.00	12.00	
29	RACE TRACK SUB, Jamestown	Distribution	115.00	17.00	
30	RADUM SUB, Pleasanton	Distribution	60.00	12.00	
31	RAINBOW SUB, Sanger	Distribution	115.00	12.00	7.20
32	RALSTON SUB, Belmont	Distribution	60.00	12.00	
33	RANCHERS COTTON SUB, Fresno	Distribution	115.00	12.00	7.20
34	RAWSON SUB, Red Bluff	Distribution	60.00	12.00	2.40
35	RED BLUFF SUB, Red Bluff	Distribution	60.00	12.00	2.40
36	REDBUD SUB, Clearlake Oaks	Distribution	115.00	12.00	7.20
37	REDWOOD CITY SUB, Redwood City	Distribution	60.00	12.00	7.20
38	REDWOOD CITY SUB, Redwood City	Distribution	60.00	4.00	
39	REEDLEY SUB, Reedley	Transmission	115.00	12.00	7.20
40	REEDLEY SUB, Reedley	Transmission	70.00	12.00	2.40

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1	RENFRO SUB, BAKERSFIELD	Distribution	115.00	12.00	7.20
2	RESEARCH SUB, San Ramon	Distribution	230.00	21.00	7.20
3	RESERVATION ROAD SUB, Salinas	Distribution	60.00	12.00	2.40
4	RICE SUB, Princeton	Distribution	60.00	12.00	4.16
5	RICHMOND R SUB, Richmond	Distribution	115.00	12.00	7.20
6	RINCON SUB, Santa Rosa	Distribution	115.00	12.00	
7	RIO BRAVO SUB, Shafter	Distribution	115.00	12.00	7.20
8	RIO DELL SUB, Rio Dell	Distribution	60.00	12.00	
9	RIPON SUB, Ripon	Distribution	115.00	17.00	
10	RISING RIVER SUB, Cassell,	Distribution	60.00	12.00	2.40
11	RIVER OAKS SUB, San Jose	Distribution	115.00	21.00	7.20
12	RIVERBANK SUB, Escalon	Distribution	115.00	12.00	
13	ROB ROY SUB, Watsonville	Distribution	115.00	21.00	7.20
14	ROCKLIN SUB, Rocklin	Distribution	60.00	12.00	7.20
15	ROSEDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
16	ROSSMOOR SUB, Walnut Creek	Distribution	230.00	12.00	
17	ROUGH & READY ISLAND SUB, Stockton	Distribution	60.00	12.00	7.20
18	SALINAS SUB, Salinas	Transmission	115.00	12.00	7.20
19	SALMON CREEK SUB, Bodega Bay	Distribution	60.00	12.00	2.40
20	SAN ARDO SUB, San Ardo	Distribution	60.00	12.00	
21	SAN BENITO SUB, San Benito	Distribution	115.00	21.00	7.20
22	SAN BERNARD SUB, Lamont	Distribution	70.00	12.00	2.40
23	SAN CARLOS SUB, San Carlos	Distribution	60.00	12.00	7.20
24	SAN CARLOS SUB, San Carlos	Distribution	60.00	4.00	2.40
25	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	115.00	12.00	7.20
26	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	12.00	
27	SAN FRAN P-HUNTERS POINT SUB, San Francisco	Distribution	115.00	12.00	
28	SAN FRAN X (MISSION) SUB, San Francisco	Distribution	115.00	12.00	7.20
29	SAN FRAN Y (LARKIN) SUB, San Francisco	Distribution	115.00	12.00	7.20
30	SAN FRAN Z (Embarcadero), San Francisco	Distribution	230.00	34.50	7.20
31	SAN JOAQUIN SUB, San Joaquin	Distribution	70.00	12.00	7.20
32	SAN JOSE A SUB, San Jose	Distribution	115.00	4.00	7.20
33	SAN JOSE A SUB, San Jose	Distribution	115.00	12.00	
34	SAN JOSE B SUB, San Jose	Distribution	115.00	12.00	7.20
35	SAN LEANDRO U SUB, San Leandro	Distribution	115.00	12.00	
36	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	12.00	7.20
37	SAN MATEO SUB, San Mateo	Transmission	115.00	21.00	
38	SAN MATEO SUB, San Mateo	Transmission	60.00	4.00	
39	SAN MIGUEL SUB, San Miguel	Distribution	70.00	12.00	7.20
40	SAN PABLO SUB, Richmond	Distribution	115.00	12.00	7.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SAN RAFAEL SUB, San Rafael	Distribution	115.00	12.00	
2	SAN RAMON SUB, San Ramon	Transmission	230.00	21.00	12.00
3	SANGER SUB, Fresno	Transmission	115.00	12.00	7.20
4	SANTA MARIA SUB, Santa Maria	Distribution	115.00	12.00	7.20
5	SANTA NELLA SUB, Santa Nella	Distribution	70.00	12.00	2.40
6	SANTA RITA SUB, Dos Palos	Distribution	70.00	12.00	2.40
7	SANTA ROSA A SUB, Santa Rosa	Distribution	115.00	12.00	7.20
8	SANTA YNEZ SUB, Santa Maria	Distribution	115.00	12.00	7.20
9	SARATOGA SUB, Saratoga	Distribution	230.00	12.00	7.20
10	SAUSALITO SUB, Sausalito	Distribution	60.00	12.00	2.40
11	SAUSALITO SUB, Sausalito	Distribution	60.00	4.00	
12	SCHINDLER SUB, Five Points	Transmission	115.00	12.00	7.20
13	SEMITROPIC SUB, Wasco	Transmission	115.00	12.00	7.20
14	SERRAMONTE SUB, Daly City	Distribution	115.00	12.00	
15	SHAFTER SUB, Shafter	Distribution	115.00	12.00	7.20
16	SHARON SUB, Chowchilla	Distribution	115.00	12.00	
17	SHEPARD SUB, Clovis	Distribution	115.00	21.00	7.20
18	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	21.00	7.20
19	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	12.00	7.20
20	SHREDDER SUB, Redwood City	Distribution	115.00	4.00	6.60
21	SILVERADO SUB, St. Helena	Distribution	115.00	21.00	
22	SISQUOC SUB, Orcutt	Distribution	115.00	12.00	7.20
23	SMYRNA SUB, Wasco	Distribution	115.00	12.00	7.20
24	SNEATH LANE SUB, San Bruno	Distribution	60.00	12.00	2.40
25	SOBRANTE SUB, Orinda	Transmission	115.00	12.00	7.20
26	SOLEDAD SUB, Soledad	Transmission	60.00	12.00	
27	SONOMA A SUB, Sonoma	Distribution	115.00	12.00	
28	SOUTH BAY #1 & #2 SUB, Tracy	Distribution	60.00	4.00	
29	SPANISH CREEK SUB,	Distribution	60.00	44.00	
30	SPENCE SUB, Salinas	Distribution	60.00	12.00	
31	SRI SUB, Menlo Park	Distribution	60.00	12.00	
32	STAFFORD SUB, Novato	Distribution	60.00	12.00	
33	STAGG SUB, Stockton	Transmission	230.00	21.00	7.20
34	STAGG SUB, Stockton	Transmission	60.00	12.00	2.40
35	STELLING SUB, Cupertino	Distribution	115.00	12.00	7.20
36	STILLWATER STA SUB, Project City	Distribution	60.00	12.00	2.40
37	STOCKDALE SUB, Bakersfield	Distribution	230.00	21.00	7.20
38	STOCKDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
39	STOCKTON A SUB, Stockton	Distribution	115.00	12.00	
40	STOCKTON A SUB, Stockton	Distribution	60.00	4.00	

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	STONE CORRAL SUB, Woodlake	Distribution	70.00	12.00	2.40
2	STONE SUB, San Jose	Distribution	115.00	12.00	7.20
3	STOREY SUB, Madera	Distribution	230.00	12.00	7.20
4	STROUD SUB, Helm	Distribution	70.00	12.00	2.40
5	SUISUN SUB, Fairfield	Distribution	115.00	12.00	7.20
6	SUNOL SUB, Sunol	Distribution	60.00	12.00	7.20
7	SWIFT SUB, San Jose	Distribution	115.00	21.00	7.20
8	SYCAMORE CREEK SUB, Chico	Distribution	115.00	12.00	
9	TAFT SUB, Taft	Transmission	115.00	12.00	7.20
10	TAMARACK SUB, Soda Springs	Distribution	60.00	12.00	7.20
11	TASSAJARA SUB, Danville	Distribution	230.00	21.00	7.20
12	TEJON SUB, Leboc	Distribution	70.00	12.00	2.40
13	TEMBLOR SUB, McKittrick	Distribution	115.00	12.00	2.40
14	TEMPLETON SUB, TEMPLETON	Transmission	230.00	21.00	7.20
15	TEVIS SUB, Oildale	Distribution	115.00	21.00	7.20
16	TIDEWATER SUB, Martinez	Distribution	230.00	21.00	
17	TIVY VALLEY SUB, Fresno	Distribution	70.00	12.00	7.20
18	TRACY SUB, Tracy	Distribution	115.00	12.00	7.20
19	TRES VIAS SUB, Oroville	Distribution	60.00	12.00	7.20
20	TRIMBLE SUB, San Jose	Distribution	115.00	12.00	7.20
21	TRIMBLE SUB, San Jose	Distribution	115.00	21.00	7.20
22	TULARE LAKE SUB, Kettleman	Distribution	70.00	12.00	2.40
23	TULUCAY SUB, Napa	Transmission	60.00	12.00	7.20
24	TUPMAN SUB, Tupman	Distribution	115.00	12.00	7.20
25	TWISSELMAN SUB, Blackwell Corners	Distribution	70.00	12.00	7.20
26	TYLER SUB, Red Bluff	Distribution	60.00	12.00	2.40
27	UKIAH SUB, Ukiah	Distribution	115.00	12.00	7.20
28	URICH SUB, Martinez	Distribution	60.00	4.00	
29	VACA DIXON SUB, Vacaville	Transmission	115.00	12.00	7.20
30	VACAVILLE SUB, Vacaville	Distribution	115.00	12.00	7.20
31	VALLEY HOME SUB, Valley Home	Distribution	60.00	17.00	
32	VALLEY HOME SUB, Valley Home	Distribution	115.00	17.00	
33	VALLEY VIEW SUB, El Sobrante	Distribution	115.00	12.00	
34	VASCO SUB, Livermore	Distribution	60.00	12.00	
35	VASONA SUB, Los Gatos	Distribution	230.00	12.00	7.20
36	VICTOR SUB, Lodi	Distribution	60.00	12.00	2.40
37	VIEJO SUB, Monterey	Distribution	60.00	21.00	7.20
38	VIERRA SUB, Lathrop	Distribution	115.00	17.00	7.20
39	VINEYARD SUB, Pleasanton	Distribution	230.00	21.00	7.20
40	VOLTA #1PH SUB, Shingletown	Distribution	60.00	12.00	2.40

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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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	WAHTOKE SUB, Reedley	Distribution	115.00	12.00	7.20
2	WASCO SUB, Wasco	Distribution	70.00	12.00	2.40
3	WATERLOO SUB, Stockton	Distribution	60.00	12.00	2.40
4	WATSONVILLE SUB, Watsonville	Distribution	60.00	12.00	7.20
5	WATSONVILLE SUB, Watsonville	Distribution	60.00	4.00	
6	WEBER SUB, Stockton	Transmission	60.00	12.00	7.20
7	WEBER SUB, Stockton	Transmission	230.00	12.00	7.20
8	WEEDPATCH SUB, Weedpatch	Distribution	70.00	12.00	7.20
9	WELLFIELD SUB, Lamont	Distribution	70.00	12.00	2.40
10	WEST FRESNO SUB, Fresno	Distribution	115.00	12.00	7.20
11	WEST LANE SUB, Stockton	Distribution	60.00	12.00	7.20
12	WEST SACRAMENTO SUB, WEST SACRAMENTO	Distribution	115.00	12.00	7.20
13	WESTLEY SUB, Westley	Distribution	60.00	12.00	2.40
14	WESTPARK SUB, Bakersfield	Distribution	115.00	12.00	7.20
15	WHEATLAND SUB, Wheatland	Distribution	60.00	12.00	7.20
16	WHEELER RIDGE SUB, Bakersfield	Transmission	70.00	12.00	7.20
17	WHISMAN SUB, Mt. View	Distribution	115.00	12.00	7.20
18	WILLIAMS SUB, Williams	Distribution	60.00	12.00	7.20
19	WILLITS A SUB, Willits	Distribution	60.00	12.00	2.40
20	WILLOW CREEK SUB, Willow Creek	Distribution	60.00	12.00	2.40
21	WILLOW PASS SUB, Pittsburg	Distribution	115.00	21.00	7.20
22	WILLOW PASS SUB, Pittsburg	Distribution	60.00	12.00	2.40
23	WILLOWS A SUB, Willows	Distribution	60.00	12.00	
24	WILSON SUB, Merced	Transmission	115.00	12.00	
25	WINDSOR SUB, Windsor	Distribution	60.00	12.00	
26	WINTERS SUB, Winters	Distribution	60.00	12.00	
27	WOLFE SUB, Cupertino	Distribution	115.00	12.00	
28	WOODCHUCK SUB, Wilson Village	Distribution	70.00	21.00	
29	WOODLAND SUB, Woodland	Distribution	115.00	12.00	7.20
30	WOODSIDE SUB, Woodside	Distribution	60.00	12.00	
31	WOODWARD SUB, Fresno	Distribution	115.00	21.00	7.20
32	WRIGHT SUB, Los Banos	Distribution	70.00	12.00	2.40
33	WYANDOTTE SUB, Oroville	Distribution	115.00	12.00	7.20
34	ZACA SUB, Santa Maria	Distribution	115.00	12.00	7.20
35	ZAMORA SUB, Zamora	Distribution	115.00	12.00	
36	Rounding issues in column f				
37	Total Distribution and Transmission Substations		82440.00	18872.10	4089.56
38	Transmission only Substations		24120.00	10990.00	1342.20
39					
40	Combined Dist Subs < 10MVA (129 substations)				

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
360	6	1	2.00000			1
334	4	1	2.00000			2
840	2		2.00000			3
80	3		1.00000			4
400	2		Sync Cond	1	40	5
400	2		2.00000			6
90	3	1	1.00000			7
840	2		2.00000			8
90	3	1	1.00000			9
76	3		1.00000			10
190	4	1	2.00000			11
214	6	1	2.00000			12
120	6	2	2.00000			13
180	3	1	1.00000			14
290	4	1	2.00000			15
90	3	1	1.00000			16
200	1		1.00000			17
588	4	2	2.00000			18
400	2		2.00000			19
240	6	1	2.00000			20
400	2		2.00000			21
170	6	1	2.00000			22
68	3	1	1.00000			23
400	2		2.00000			24
840	2		2.00000			25
80	3	1	1.00000			26
600	2		2.00000			27
823	4	1	2.00000			28
117	3	1	1.00000			29
120	3		1.00000			30
1122	3	1	2.00000			31
255	4	1	2.00000			32
80	3		1.00000			33
840	2		2.00000			34
38	3		1.00000			35
134	3		1.00000			36
400	2		2.00000			37
180	3	1	1.00000			38
50	3	1	1.00000			39
1260	3		Sync Cond	2	80	40

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
40	1		1.00000			1
400	2		SVC	1	50	2
400	2		2.00000			3
823	4	1	2.00000			4
400	2		2.00000			5
76	3		1.00000			6
400	2		2.00000			7
1260	3		3.00000			8
90	3	1	1.00000			9
400	2		2.00000			10
840	2		2.00000			11
90	3		1.00000			12
400	2		2.00000			13
334	4		2.00000			14
840	3	1	1.00000			15
840	2		2.00000			16
100	1	1	2.00000			17
1243	5	1	Sync Cond	2	80	18
280	4	1	2.00000			19
90	3	1	1.00000			20
50	3		1.00000			21
840	2		2.00000			22
3366	9	2	3.00000			23
1630	10	1	4.00000			24
1260	3		3.00000			25
3364	9	2	3.00000			26
90	3		1.00000			27
200	1		1.00000			28
134	3	1	1.00000			29
1260	3		1.00000			30
1243	5	1	3.00000			31
269	3	1	1.00000			32
1680	4		2.00000			33
1122	3	1	1.00000			34
200	4	1	1.00000			35
80	3		1.00000			36
1646	8	1	SVC	1	220	37
60	3		1.00000			38
168	3	1	1.00000			39
420	1		1.00000			40

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SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
840	2		2.00000			1
80	3	1	1.00000			2
840	2		2.00000			3
95	3		1.00000			4
823	4	1	2.00000			5
190	4	1	2.00000			6
254	6		2.00000			7
1122	3	1	1.00000			8
200	2		2.00000			9
400	2		2.00000			10
420	1		1.00000			11
100	1		1.00000			12
823	4	1	2.00000			13
200	1		1.00000			14
200	2		2.00000			15
1260	3		Sync Cond	2	88	16
90	3	1	1.00000			17
30	3	1	1.00000			18
90	3	1	1.00000			19
90	3	1	1.00000			20
823	4	1	2.00000			21
75	6		2.00000			22
600	2		2.00000			23
1008	5	1	3.00000			24
1122	3	1	1.00000			25
162	4		2.00000			26
175	1		1.00000			27
806	6	1	2.00000			28
3366	9	2	3.00000			29
90	3	1	1.00000			30
400	2		2.00000			31
290	4	1	2.00000			32
1094	8		3.00000			33
2244	6	1	2.00000			34
334	4	1	2.00000			35
600	2		2.00000			36
60	3	1	1.00000			37
400	2		2.00000			38
689	4	1	2.00000			39
45	1		1.00000			40

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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)	
90	2		2.00000			1
27	2		2.00000			2
13	1		1.00000			3
60	2		2.00000			4
41	2		2.00000			5
49	4	1	2.00000			6
30	1		1.00000			7
19	3	1	1.00000			8
16	1		1.00000			9
38	2		2.00000			10
16	1		1.00000			11
11	3	1	1.00000			12
16	1		1.00000			13
16	1		1.00000			14
27	4	1	2.00000			15
60	2		2.00000			16
13	3	1	1.00000			17
210	3		3.00000			18
30	1		1.00000			19
90	2		2.00000			20
25	2		2.00000			21
16	3	1	1.00000			22
16	1		1.00000			23
112	2		2.00000			24
45	1		1.00000			25
225	3		3.00000			26
13	1		1.00000			27
120	3		3.00000			28
39	4		2.00000			29
90	2		2.00000			30
75	2		2.00000			31
16	1		1.00000			32
13	1		1.00000			33
57	2		2.00000			34
57	3		3.00000			35
16	6	1	2.00000			36
70	3		3.00000			37
135	3		3.00000			38
16	2		2.00000			39
11	3	1	1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
15	3		1.00000			1
20	3		1.00000			2
13	1		1.00000			3
13	3	1	1.00000			4
90	2		2.00000			5
13	1		1.00000			6
16	1		1.00000			7
30	1		1.00000			8
30	1		1.00000			9
225	3		3.00000			10
120	3		3.00000			11
90	3		3.00000			12
21	2		2.00000			13
76	3		3.00000			14
90	2		2.00000			15
45	1		1.00000			16
30	1		1.00000			17
46	2		2.00000			18
11	1		1.00000			19
20	3		1.00000			20
30	1		1.00000			21
15	3		1.00000			22
19	3		1.00000			23
135	3		3.00000			24
21	3	1	1.00000			25
16	1		1.00000			26
41	2		2.00000			27
90	2		2.00000			28
11	1		1.00000			29
6	3	1	1.00000			30
60	2		2.00000			31
24	1		1.00000			32
11	6		1.00000			33
37	3		2.00000			34
16	1		1.00000			35
16	1		1.00000			36
14	2		2.00000			37
25	2		2.00000			38
50	4		2.00000			39
45	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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.
90	2		2.00000			1
30	3	1	1.00000			2
39	4	1	2.00000			3
11	1		1.00000			4
45	1		1.00000			5
25	2		2.00000			6
13	1		1.00000			7
41	2		2.00000			8
16	1		1.00000			9
21	3	1	1.00000			10
32	2		2.00000			11
13	1		1.00000			12
13	1		1.00000			13
61	2		2.00000			14
11	3	1	1.00000			15
135	3		3.00000			16
29	2		2.00000			17
135	3		3.00000			18
16	1		1.00000			19
20	6	1	2.00000			20
19	3	1	1.00000			21
90	2		2.00000			22
45	1		1.00000			23
27	2		2.00000			24
21	3		1.00000			25
61	2		2.00000			26
59	3		3.00000			27
12	1		1.00000			28
21	6	1	2.00000			29
225	3		3.00000			30
42	3	1	1.00000			31
20	3	1	1.00000			32
28	4		2.00000			33
46	2		2.00000			34
45	1		1.00000			35
13	3	2	1.00000			36
58	10	3	2.00000			37
30	1		1.00000			38
43	2		2.00000			39
7	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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.
29	6	1	2.00000			1
130	3		3.00000			2
75	2		2.00000			3
35	3		3.00000			4
7	1		1.00000			5
30	1		1.00000			6
90	2		2.00000			7
19	3	1	1.00000			8
16	3		1.00000			9
16	1		1.00000			10
60	2		2.00000			11
135	3		3.00000			12
135	3		3.00000			13
90	2		2.00000			14
75	2		2.00000			15
16	1		1.00000			16
75	2		2.00000			17
14	1		1.00000			18
43	2		2.00000			19
61	2		2.00000			20
60	2		2.00000			21
11	3	1	1.00000			22
30	1		1.00000			23
135	3		3.00000			24
75	2		2.00000			25
11	1		1.00000			26
13	1		1.00000			27
105	3		3.00000			28
32	6	1	2.00000			29
180	4		4.00000			30
25	2	1	2.00000			31
16	1		1.00000			32
16	1		1.00000			33
8	1		1.00000			34
135	3		3.00000			35
45	1		1.00000			36
90	2		2.00000			37
25	4		2.00000			38
90	2		2.00000			39
63	2		2.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	1		1.00000			1
127	3		3.00000			2
32	2		2.00000			3
180	4		4.00000			4
23	2		2.00000			5
11	1		1.00000			6
13	1		1.00000			7
11	3	1	1.00000			8
13	1		1.00000			9
21	3	1	1.00000			10
90	2	1	2.00000			11
13	1		1.00000			12
50	3		1.00000			13
60	2		2.00000			14
30	1		1.00000			15
60	2		2.00000			16
225	3		3.00000			17
30	1		1.00000			18
22	2		2.00000			19
25	3		1.00000			20
50	2		2.00000			21
11	1		1.00000			22
21	3	1	1.00000			23
60	2		2.00000			24
45	1		1.00000			25
19	3	1	1.00000			26
60	2		2.00000			27
105	3		3.00000			28
32	2		2.00000			29
25	4		2.00000			30
49	4	1	2.00000			31
60	2		2.00000			32
16	1		1.00000			33
25	1		1.00000			34
13	1		1.00000			35
16	1		1.00000			36
21	3	1	SVC	1	15	37
45	1		1.00000			38
19	3		1.00000			39
22	4		2.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	3		1.00000			1
16	1		1.00000			2
30	1		1.00000			3
32	2		2.00000			4
7	1		1.00000			5
16	1		1.00000			6
22	2		2.00000			7
27	2		2.00000			8
81	3		3.00000			9
90	2		2.00000			10
19	3	1	1.00000			11
60	2		2.00000			12
32	2		2.00000			13
12	7	1	2.00000			14
60	2		2.00000			15
21	3		3.00000			16
50	5		3.00000			17
90	3		3.00000			18
16	1		1.00000			19
13	2		2.00000			20
12	1		1.00000			21
29	2		2.00000			22
60	2		2.00000			23
19	2		2.00000			24
16	3		1.00000			25
46	2		2.00000			26
13	1		1.00000			27
150	2		2.00000			28
90	2		2.00000			29
77	3		3.00000			30
60	2		2.00000			31
90	2		2.00000			32
70	2		2.00000			33
25	1		1.00000			34
16	1		1.00000			35
13	3	1	1.00000			36
90	2		2.00000			37
16	1		1.00000			38
133	6		2.00000			39
77	3		2.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1		1.00000			1
4	1		1.00000			2
4	1		1.00000			3
20	3		1.00000			4
46	2		2.00000			5
16	1		1.00000			6
13	1		1.00000			7
16	1		1.00000			8
29	2		2.00000			9
90	2		2.00000			10
39	2		2.00000			11
105	3		3.00000			12
22	1		1.00000			13
27	2		2.00000			14
30	1		1.00000			15
60	2		2.00000			16
135	3		3.00000			17
90	2		2.00000			18
11	3	1	1.00000			19
11	3		1.00000			20
47	3		3.00000			21
90	2		2.00000			22
135	3		3.00000			23
23	2		2.00000			24
49	4		2.00000			25
75	2		2.00000			26
215	4		4.00000			27
25	3	1	1.00000			28
90	2		2.00000			29
75	2		2.00000			30
76	3		3.00000			31
30	1		1.00000			32
165	3		3.00000			33
14	2		2.00000			34
145	5	1	3.00000			35
45	1		1.00000			36
75	2		2.00000			37
90	2		2.00000			38
91	3		3.00000			39
19	3		1.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
27	2		2.00000			1
25	6		2.00000			2
45	1		1.00000			3
11	3		1.00000			4
100	3		3.00000			5
30	1	1	1.00000			6
90	2		2.00000			7
46	2		2.00000			8
21	3	1	1.00000			9
5	3	1	1.00000			10
45	1		1.00000			11
45	1		1.00000			12
51	3		3.00000			13
13	3	1	1.00000			14
32	2		2.00000			15
13	3	1	1.00000			16
43	2		2.00000			17
21	3	1	1.00000			18
5	3	1	1.00000			19
29	2		2.00000			20
19	3		1.00000			21
45	1		1.00000			22
71	7		3.00000			23
30	1		1.00000			24
21	2		2.00000			25
45	1		1.00000			26
45	1		1.00000			27
105	3		3.00000			28
135	3		3.00000			29
135	8	1	4.00000			30
11	3		1.00000			31
32	2		2.00000			32
13	3	1	1.00000			33
49	4	1	2.00000			34
43	4	1	2.00000			35
11	3	1	1.00000			36
90	2		2.00000			37
21	2		2.00000			38
32	2		2.00000			39
105	3		3.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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.
13	4	1	1.00000			1
45	1		1.00000			2
170	3		3.00000			3
5	3	1	1.00000			4
30	1		1.00000			5
32	2		2.00000			6
18	2		2.00000			7
45	1		1.00000			8
45	1		1.00000			9
21	3	1	1.00000			10
45	1		1.00000			11
11	1		1.00000			12
34	4	1	2.00000			13
23	2		2.00000			14
60	2		2.00000			15
6	3	1	1.00000			16
90	2		2.00000			17
75	2		2.00000			18
11	1		1.00000			19
14	3	1	1.00000			20
43	2		2.00000			21
90	2		2.00000			22
45	1		1.00000			23
135	3		3.00000			24
29	2		2.00000			25
11	3	1	1.00000			26
45	1		1.00000			27
120	3		3.00000			28
30	1		1.00000			29
16	1		1.00000			30
105	3		3.00000			31
115	3		2.00000			32
135	3		2.00000			33
16	1		1.00000			34
79	5		3.00000			35
30	1		1.00000			36
150	2		2.00000			37
90	2		2.00000			38
20	4	1	2.00000			39
29	2		2.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
41	4		2.00000			1
16	1		1.00000			2
32	2		2.00000			3
90	2		2.00000			4
45	1		1.00000			5
90	2		2.00000			6
45	1		1.00000			7
23	2		2.00000			8
43	3		2.00000			9
195	4		4.00000			10
175	4		4.00000			11
120	3		3.00000			12
38	3	1	1.00000			13
135	3		3.00000			14
90	3		3.00000			15
75	2		2.00000			16
42	6	1	2.00000			17
31	4		2.00000			18
16	1		1.00000			19
45	1		1.00000			20
18	4		2.00000			21
60	2		2.00000			22
16	1		1.00000			23
6	3		1.00000			24
25	7		2.00000			25
11	1		1.00000			26
22	3		1.00000			27
45	1		1.00000			28
41	2		2.00000			29
25	2		2.00000			30
5	3	1	1.00000			31
16	1		1.00000			32
23	2		2.00000			33
11	1		1.00000			34
45	1		1.00000			35
30	1		1.00000			36
30	1		1.00000			37
45	1		1.00000			38
45	1		1.00000			39
30	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
45	1		1.00000			1
90	3		3.00000			2
135	3		SVC	1	60	3
195	3		3.00000			4
14	6	1	2.00000			5
50	2		2.00000			6
13	1		1.00000			7
61	2		2.00000			8
58	4		2.00000			9
57	5	1	3.00000			10
45	1		1.00000			11
22	4		2.00000			12
135	3		3.00000			13
41	4	1	2.00000			14
30	1		1.00000			15
30	1		1.00000			16
39	2		2.00000			17
135	3		3.00000			18
45	1		1.00000			19
13	1		1.00000			20
11	1		1.00000			21
16	1		1.00000			22
65	2		1.00000			23
32	2		2.00000			24
45	1		StatCom	2	8	25
45	1		1.00000			26
11	1		1.00000			27
32	2		2.00000			28
16	1		1.00000			29
25	6		2.00000			30
30	1		1.00000			31
16	4		2.00000			32
16	1		1.00000			33
19	3		1.00000			34
50	5		3.00000			35
23	3		2.00000			36
70	5		3.00000			37
14	3		1.00000			38
30	1		1.00000			39
30	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
90	2		2.00000			1
45	1		1.00000			2
11	1		1.00000			3
14	2		2.00000			4
90	2		2.00000			5
32	2		2.00000			6
64	4		2.00000			7
11	3		1.00000			8
73	2		2.00000			9
11	3	1	1.00000			10
90	2		2.00000			11
73	4	1	2.00000			12
23	1		1.00000			13
27	4	1	2.00000			14
30	1		1.00000			15
90	2		2.00000			16
16	1		1.00000			17
90	2		2.00000			18
11	3	1	1.00000			19
11	3	1	1.00000			20
30	1		1.00000			21
19	3		1.00000			22
29	2		2.00000			23
12	3	1	1.00000			24
186	3		3.00000			25
180	4		4.00000			26
98	2		2.00000			27
375	5		5.00000			28
450	6		6.00000			29
345	3		3.00000			30
18	2		2.00000			31
40	2		3.00000			32
30	1		1.00000			33
180	4		2.00000			34
160	4		4.00000			35
135	3		3.00000			36
45	1		1.00000			37
13	3	1	1.00000			38
16	1		1.00000			39
45	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
120	3		3.00000			1
300	4		4.00000			2
60	2		2.00000			3
90	2		2.00000			4
27	2		2.00000			5
12	3		1.00000			6
135	3		3.00000			7
41	2		2.00000			8
157	3		3.00000			9
21	3	1	1.00000			10
5	3	1	1.00000			11
60	2		2.00000			12
30	1		1.00000			13
13	1		1.00000			14
72	4	1	2.00000			15
11	1		1.00000			16
45	1		1.00000			17
61	2		2.00000			18
16	1		1.00000			19
15	3	1	1.00000			20
60	2		2.00000			21
32	2		2.00000			22
49	4		2.00000			23
19	6		2.00000			24
30	1		1.00000			25
11	1		1.00000			26
60	2		2.00000			27
25	3		3.00000			28
19	1		1.00000			29
13	3	1	2.00000			30
13	1		1.00000			31
25	2		2.00000			32
150	2		2.00000			33
51	4	1	2.00000			34
105	3		2.00000			35
11	3	1	1.00000			36
225	3		3.00000			37
75	2		2.00000			38
105	3		3.00000			39
22	6		1.00000			40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
17	2		2.00000			1
45	1		1.00000			2
90	2		2.00000			3
21	3	1	1.00000			4
120	3		3.00000			5
13	1		1.00000			6
135	3		3.00000			7
90	3		3.00000			8
27	2		2.00000			9
13	1		1.00000			10
225	3		3.00000			11
49	4		2.00000			12
21	3	1	1.00000			13
90	2		2.00000			14
90	2		2.00000			15
150	2		2.00000			16
13	1		1.00000			17
121	4		4.00000			18
16	1		1.00000			19
90	2		2.00000			20
90	2		2.00000			21
24	4	2	2.00000			22
30	1		1.00000			23
61	2		2.00000			24
32	2		2.00000			25
19	6		2.00000			26
29	2		2.00000			27
10	3	1	1.00000			28
105	3		3.00000			29
120	3		3.00000			30
6	3	1	1.00000			31
30	1		1.00000			32
29	2		2.00000			33
17	6		2.00000			34
90	2		4.00000			35
30	1		1.00000			36
60	2		2.00000			37
90	2		2.00000			38
150	2	1	2.00000			39
21	3	1	1.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2		2.00000			1
20	3		1.00000			2
11	1		1.00000			3
16	1		1.00000			4
8	1		1.00000			5
50	2		2.00000			6
90	2		2.00000			7
30	1		1.00000			8
24	4		2.00000			9
135	3		3.00000			10
30	1		1.00000			11
105	3		3.00000			12
29	2		2.00000			13
105	3		3.00000			14
44	4	1	2.00000			15
30	1		1.00000			16
105	3		3.00000			17
27	2		2.00000			18
19	3	1	1.00000			19
13	3	1	1.00000			20
30	1		1.00000			21
11	3	1	1.00000			22
14	3	1	1.00000			23
14	1		1.00000			24
30	1		1.00000			25
13	1		1.00000			26
120	3		3.00000			27
23	3		1.00000			28
135	3		3.00000			29
60	2		2.00000			30
135	3		3.00000			31
13	1		1.00000			32
120	3		3.00000			33
11	1		1.00000			34
27	2		2.00000			35
-57						36
96173	1780	159		13	641	37
64915	359	57				38
						39
675	331	54				40

Schedule Page: 426.3 Line No.: 29 Column: e

2.4 & 7.2

Schedule Page: 426.3 Line No.: 35 Column: e

2.4 & 7.2

Schedule Page: 426.4 Line No.: 27 Column: e

2.4 & 7.2

Schedule Page: 426.5 Line No.: 17 Column: e

2.4 & 7.2

Schedule Page: 426.8 Line No.: 17 Column: e

2.4 & 7.2

Schedule Page: 426.9 Line No.: 9 Column: e

2.4 & 7.2

Schedule Page: 426.9 Line No.: 25 Column: e

2.4 & 7.2

Schedule Page: 426.10 Line No.: 22 Column: c

60 or 115

Schedule Page: 426.12 Line No.: 20 Column: c

70 or 115

Schedule Page: 426.13 Line No.: 2 Column: e

2.4 & 7.2

Schedule Page: 426.13 Line No.: 17 Column: e

2.4 & 7.2

Schedule Page: 426.16 Line No.: 12 Column: e

2.4 & 7.2

Schedule Page: 426.17 Line No.: 36 Column: a

The original entries in column f were in two decimal places, which the FERC software rounds automatically to whole numbers. The entry here is an adjustment to present the correct total.

Schedule Page: 426.17 Line No.: 38 Column: a

Substation voltage classes are listed separately for each substation. Therefore, there will be multiple line entries for substations having more than one voltage class. Substations having combined total capacity of =>10 MVA are listed individually. Substations with less than 10 MVA capacity are lumped together in one line item. All transmission substations are =>10 MVA.

There are 92 Transmission Substations and 605 Distribution Substations. This represents a total of 697 physical transmission and distribution substations (92+605=697). All transmission and distribution substations are unattended.

Any substation that has a transmission-to-transmission transformation (Primary voltage >=60kV and secondary voltage >= 60kV) is defined as a transmission station, regardless of the number of distribution assets in the station. Hence, substations with both transmission and distribution (secondary voltage <60 kV) transformers are characterized as Transmission in the list. There are 59 Transmission Substations with both transmission and distribution transformers; one of them <10MVA. There are 664 substations with distribution transformer banks. (605+59 = 664)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2		PG&E Corporation		
3	Corporate A&G Allocations		923, 426.4, 426.5	94,248,645
4	Total - Administrative & General Expenses			94,248,645
5				
6	Rent Expense	Eureka Energy Company	532.0	321,288
7				
8	Total Non-power Goods/Srv.provided by Affilia			94,569,933
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21		PG&E Corporation	930.2	
22	ACCOUNTING			536,406
23	ADMINISTRATION			509,322
24	AFFILIATE RULES COMPLIANCE SUPPORT			24,463
25	BANKING SERVICES			33,980
26	BOD EXPENSES			23
27	BUSINESS PLANNING SERVICES			26,436
28	COMPLIANCE & ETHICS SUPPORT			8,469
29	CONSULTING SERVICES			5,656
30	CORPORATE SECRETARY SUPPORT			1,885
31	CORPORATE SUSTAINABILITY SUPPORT			242,594
32	FINANCIAL FORECASTING AND ANALYSIS			56,932
33	FLEET SERVICES			27,617
34	HUMAN RESOURCES SUPPORT			72,382
35	INFORMATION TECHNOLOGY			450,881
36	INSURANCE SUPPORT			13,577
37	INTERNAL AUDIT SERVICES			6,001
38	INVESTOR RELATIONS SUPPORT			9,802
39	LEGAL			98,874
40	MISC EXPENSE			41
41	REAL ESTATE AND FACILITY			667,510
42	SECURITY SUPPORT			327,578
1	**Non-power Goods or Services Provided by Affiliated**			
2				

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

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	SOURCING SUPPORT			122,355
23	STRATEGIC ANALYSIS SUPPORT			47,456
24	TAX SERVICES			89,462
25	EMPLOYEE TRANSFER FEE			351,426
26	INTEREST			40,201
27				
28				
29				
30	Total - A&G Direct Charges to PG&E Corp			3,771,329
31				
32		FUELCO	930.2	
33	ACCOUNTING			18,032
34	CFO SUPPORT			6,011
35	FUEL PURCHASING SUPPORT			426,283
36	LEGAL			1,208
37	SUPPLY CHAIN SUPPORT			9,051
38				
39	Total - A&G Direct Charges to FUELCO			460,585
40				
41	TOTAL NON-POWER GOODS/SRV PROVIDED			
42	FOR AFFILIATES			4,231,914

Schedule Page: 429 Line No.: 3 Column: a

1. Allocation of Corporation cost center costs were based on one of the following methods:
   (A) 3-Factor Method
   Simple Average of the following ratios:
   (a) Affiliate Assets/Total Consolidated Assets
   (b) Affiliate Operating Expenses less Fuel purchase costs/Total Consolidated Operating Expenses less Fuel Purchase Cost
   (c) Affiliate Headcount/Total Consolidated Headcount
   (B) Capitalization
   Affiliate Capitalization/Total Consolidated Capitalization
   (C) Headcount
   Affiliate Headcount/Total Consolidated Headcount

For 2018, the Corporation’s A&G Allocation Rate is rounded to 99% based on the calculation from three methodologies above.

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