THIS FILING IS

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

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

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

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	End of 2017/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	02 Year/Period of Report End of 2017/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 77 BEALE STREET, P.O. BOX 770000, SAN FRANCISCO, CA 94177	
05 Name of Contact Person SUSAN HUNTER	06 Title of Contact Person DIRECTOR, CORP ACCOUNTIG
07 Address of Contact Person *(Street, City, State, Zip Code)* 77 BEALE STREET, P.O. BOX 770000, SAN FRANCISCO, CA 94177	

08 Telephone of Contact Person,*Including Area Code* (415) 973-5072	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 03/09/2018

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name DAVID THOMASON	03 Signature DAVID THOMASON	04 Date Signed *(Mo, Da, Yr)* 03/09/2018
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	03/09/2018	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	NOT APPLICABLE
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NONE
18	Electric Plant Held for Future Use	214	NONE
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NONE
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	NOT APPLICABLE
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	NOT APPLICABLE
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NOT APPLICABLE
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

GENERAL INFORMATION

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

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.

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	03/09/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	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				

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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				
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				
10				
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
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	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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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	03/09/2018	2017/Q4

FOOTNOTE DATA

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.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report End of 2017/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President, Electric	Geisha J. Williams	991,667
2	President and Chief Operating Officer	Nickolas Stavropoulos	777,500
3	Senior VP, Generation and Chief Nuclear Officer	Edward D. Halpin	591,783
4	Senior VP and Chief Information Officer	Karen A. Austin	555,800
5	Senior VP, Human Resources and Chief Diversity Officer	Dinyar B. Mistry	455,833
6	Senior VP and Chief Ethics and Compliance Officer and	Julie M. Kane	452,500
7	Deputy General Council		
8	Senior VP, Gas Operations	Jesus Soto, Jr.	442,150
9	Senior VP and Chief Customer Officer	Loraine M. Giammona	429,483
10	Senior VP, Strategy and Policy	Steven Malnight	403,450
11	Senior VP, Energy Policy and Procurement	Fong Wan	393,167
12	Senior VP, Electric Operations	Patrick M. Hogan	384,167
13	Vice President, Chief Financial Officer and Controller	David S. Thomason	295,833
14	Senior VP, Safety and Shared Services	Desmond A. Bell	150,835
15	Senior VP, External Affairs and Public Policy	Helen A. Burt	70,330
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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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 104 Line No.: 1 Column: b

Ms. Williams, formerly President, Electric of Pacific Gas and Electric Company, became CEO and President of PG&E Corporation on March 1, 2017.

Schedule Page: 104 Line No.: 2 Column: b

Mr. Stavropolous, formerly President, Gas, became President and Chief Operating Officer on March 1, 2017.

Schedule Page: 104 Line No.: 3 Column: b

Mr. Halpin's employment ended December 30, 2017.

Schedule Page: 104 Line No.: 5 Column: b

Mr. Mistry, formerly Senior VP, Human Resources, became Senior VP Human Resources and Chief Diversity Officer on February 1, 2017.

Schedule Page: 104 Line No.: 6 Column: b

Ms. Kane, formerly Senior VP and Chief Ethics and Compliance Officer, became Senior VP, Chief Ethics and Compliance Officer and Deputy General Council on March 21, 2017.

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

Mr. Malnight, formerly Senior VP, Regulatory Affairs, became Senior VP, Strategy and Policy on March 1, 2017.

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

Mr. Hogan, formerly Senior VP, Electric Transmission and Distribution Operations, became Senior VP, Electric Operations on February 1, 2017.

Schedule Page: 104 Line No.: 14 Column: b

Mr. Bell's employment ended May 8, 2017.

Schedule Page: 104 Line No.: 15 Column: b

Ms. Burt's employment ended March 1, 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	03/09/2018	End of 2017/Q4

DIRECTORS

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

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

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	03/09/2018	End of 2017/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		San Francisco, CA 94105
2		
3	Anne Shen Smith	c/o PG&E Corporation
4		77 Beale Street, 32nd Floor
5		San Francisco, CA 94105
6		
7	Nickolas Stavropoulos ***	c/o PG&E Corporation
8		77 Beale Street, 32nd Floor
9		San Francisco, CA 94105
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11	Barry Lawson Williams ***	c/o PG&E Corporation
12		77 Beale Street, 32nd Floor
13		San Francisco, CA 94105
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15	Geisha J. Williams ***	c/o PG&E Corporation
16		77 Beale Street, 32nd Floor
17		San Francisco, CA 94105
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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	03/09/2018	End of 2017/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	03/09/2018	End of 2017/Q4

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

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

[ ] 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	03/09/2018	End of 2017/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1		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.

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	03/09/2018	2017/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

PACIFIC GAS AND ELECTRIC COMPANY
IMPORTANT CHANGES DURING THE YEAR

For the Quarter/Year Ended December 31, 2017

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 March 23, 2017, the Five Points Switching Station was released to operations. This project, located in Fresno County, constructed a new 5-breaker ring bus, expandable to breaker-an-a-half (BAAH) 70 kV Switching Station. This project was built to facilitate the interconnection of a 20 Mw solar generation by Whitney Point to Pacific Gas and Electric Company's Schindler - Huron - Gates 70 kV Line.

   On June 8, 2017, Las Aguilas 230 kV Switching Station was released to operations. This project, located in San Benito County, constructed a new three bay, breaker-and-a-half (BAAH) 230 kV Las Aguilas Switching Station. This project was built to facilitate the interconnection of a 240 Mw solar generation project by Panoche Valley Solar to Pacific Gas and Electric Company's Moss Landing - Panoche and Coburn - Panoche 230 kV Lines.

   On December 20, 2017, the Windsor distribution substation was released for operations. The substation is equipped with a three breaker 60kV ring bus, one 60/12kV stepdown LTC transformer, and a 12kV switchgear. Three new distribution feeders are scheduled to be installed and energized in February 2018. Located in the town of Windsor in Sonoma County, the new substation is expected to increase area

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

capacity, reliability, operational flexibility, and eliminate project asset overloads.

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:

On November 27, 2017 PG&E priced $1.15 billion of 3.30% 10-year senior unsecured notes and $850 million of 3.95% 30-year senior unsecured notes. The notes were issued as 144A with registration rights private securities and are expected to be registered within one year. The transaction settled on November 29, 2017.

On November 29, 2017, PG&E issued a make whole notice on $400M of 8.25% senior notes due October 2018. On November 30, 2017, the bonds were defeased to relieve PG&E of the indebtedness. The bondholders received the funds on December 29. 2017.

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

b) Bank Credit Facilities:

At December 31, 2017, the Utility had $49 million of letters of credit outstanding, $50 million of commercial paper outstanding, and no borrowings under its $3 billion 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 1, 2017 to December 31, 2017, $32,670,940 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of December 31, 2017, there was a total of $96,361,940 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, 2017, 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:

No important changes to report.

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, 2017, 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 2017, three beneficial owners of at least 5 percent of PG&E Corporation common stock as of December 31, 2016 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"). 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 the 2017, 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 2017 through March 2018 (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:

- Jeh C. Johnson, Director

The following individuals are no longer Directors of the Utility:

- Anthony F. Earley, Jr., Director
- Maryellen C. Herringer, Director
- Barry Lawson Williams, Director

Officers

The following individuals become officers of the Utility:

- Forrest E. Miller, Non-executive Chairman of the Board
- Melvin Christopher, Vice President, Gas Transmission and Distribution Operations
- Jon A. Franke, Vice President, Generation Technical Services
- Janet C. Loduca, Vice President and Deputy General Counsel
- Jamie Martin, Vice President, Business Finance

The following individual's titles changed:

- Nickolas Stavropoulos, President and Chief Operating Officer (formerly President, Gas)
- Patrick M. Hogan, Senior Vice President, Electric Operations (formerly Senior Vice

President, Electric Transmission and Distribution)
- Julie M. Kane, Senior Vice President, Chief Ethics and Compliance Officer, and Deputy General Counsel (formerly Senior Vice President and Chief Ethics and Compliance Officer)
- Steven E. Malnight, Senior Vice President, Strategy and Policy (formerly Senior Vice President, Regulatory Affairs)
- Dinyar B. Mistry, Senior Vice President, Human Resources and Chief Diversity Officer (formerly Senior Vice President, Human Resources)
- Laura L. Butler, Vice President (formerly Vice President, Talent Management and Chief Diversity Officer)
- Stephen J. Cairns, Vice President, Internal Audit and Chief Risk Officer (formerly Vice President, Internal Audit)
- Jon A. Franke, Vice President Power Generation (formerly Vice President, Generation Technical Services)
- John C. Higgins, Vice President, Safety and Health and Chief Safety Officer (formerly Vice President, Safety and Health; formerly Vice President, Gas Transmission and Distribution Operations)
- Robert S. Kenney, Vice President, Regulatory Affairs (formerly Vice President, CPUC Regulatory Relations)
- Travis T. Kiyota, Vice President, California External Affairs (formerly Vice President, Community Relations and Public Affairs)
- Jamie Martin, Vice President, Finance and Planning (formerly Vice President, Business Finance)
- James M. Welsch, Vice President, Nuclear Generation and Chief Nuclear Officer (formerly Vice President, Nuclear Generation)
- Andrew K. Williams, Vice President, Land and Environmental Management (formerly Vice President, Safety, Health, and Environment)

The following individuals are no longer officers of the Utility:

- Barry Lawson Williams, Non-executive Chairman of the Board
- Geisha J. Williams, President, Electric
- Desmond A. Bell, Senior Vice President, Safety and Shared Services
- Helen A. Burt, Senior Vice President, External Affairs and Public Policy
- Edward D. Halpin, Senior Vice President, Generation and Chief Nuclear Officer
- William D. Arndt, Vice President, Electric Business and Performance Management
- Laura L. Butler, Vice President
- DeAnn Hapner, Vice President, FERC and ISO Relations
- Sanford L. Hartman, Vice President and Managing Director, Law
- Albert F. Torres, Vice President

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 9,516,370 shares as of December 31, 2016 to 9,556,157 shares as of December 31, 2017. (Approximately 93 percent of the total preferred shares outstanding).

Dividend Payments

Refer to Note 5, Equity, of the Notes to Financial Statements on page 123 of the FERC Form 1.

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	03/09/2018	2017/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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	03/09/2018	End of 2017/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	81,000,792,691	76,683,196,010
3	Construction Work in Progress (107)	200-201	2,470,588,868	2,183,195,426
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		83,471,381,559	78,866,391,436
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	35,680,789,356	33,823,849,160
6	Net Utility Plant (Enter Total of line 4 less 5)		47,790,592,203	45,042,542,276
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	261,763,030	280,145,003
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		416,084,176	402,677,540
10	Spent Nuclear Fuel (120.4)		2,265,141,307	2,164,292,005
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,505,050,242	2,381,791,989
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		437,938,271	465,322,559
14	Net Utility Plant (Enter Total of lines 6 and 13)		48,228,530,474	45,507,864,835
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)		30,929,381	28,119,383
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	48,859,887	49,368,145
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	195,017,512	373,856,814
24	Other Investments (124)		10,942	88,957
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,863,247,030	2,606,497,177
29	Special Funds (Non Major Only) (129)		553,022,543	368,120,654
30	Long-Term Portion of Derivative Assets (175)		102,130,395	140,213,840
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,793,217,690	3,566,264,970
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		57,718,289	68,255,295
36	Special Deposits (132-134)		6,951,064	6,764,423
37	Working Fund (135)		146,305	145,905
38	Temporary Cash Investments (136)		385,000,000	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,368,326,668	1,365,313,422
41	Other Accounts Receivable (143)		1,294,343,299	1,234,905,330
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		64,476,202	58,476,163
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		21,355,991	20,742,129
45	Fuel Stock (151)	227	1,375,066	1,429,732
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	365,624,133	346,493,508
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	419,851,065	403,970,714

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	03/09/2018	End of 2017/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		195,017,512	373,856,814
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		113,465,206	115,567,316
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		227,100,005	149,578,164
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		945,999,103	1,098,140,120
62	Miscellaneous Current and Accrued Assets (174)		14,376,070	54,386,274
63	Derivative Instrument Assets (175)		129,373,589	221,422,287
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		102,130,395	140,213,840
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)		4,989,381,744	4,514,567,802
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		131,251,529	117,574,986
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,683,889	3,800,000
72	Other Regulatory Assets (182.3)	232	5,018,800,793	9,306,684,417
73	Prelim. Survey and Investigation Charges (Electric) (183)		82,918	89,260
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)		3,237,868	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	55,551,664	57,798,631
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)		97,418,150	95,397,747
82	Accumulated Deferred Income Taxes (190)	234	1,728,161,422	2,549,460,531
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		7,038,188,233	12,130,805,572
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		64,105,225,466	65,775,410,504

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	03/09/2018	end of 2017/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	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	6,735,547,928	6,280,547,928
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	9,712,977,993	8,815,133,482
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-56,608,615	-52,118,510
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)	6,290,667	2,433,257
16	Total Proprietary Capital (lines 2 through 15)		19,747,402,038	18,395,190,222
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	18,032,100,000	16,877,100,001
19	(Less) Reaquired Bonds (222)	256-257	0	145,000,000
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)		14,860,769	16,824,052
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		80,156,440	74,086,768
24	Total Long-Term Debt (lines 18 through 23)		17,966,804,329	16,674,837,285
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		17,990,411	30,502,448
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,003,439,991	1,093,392,860
29	Accumulated Provision for Pensions and Benefits (228.3)		2,025,769,027	2,548,296,358
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,039,213,260	1,087,354,964
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		57,007,082	88,887,394
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		4,899,104,864	4,684,437,697
35	Total Other Noncurrent Liabilities (lines 26 through 34)		9,042,524,635	9,532,871,721
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		800,000,001	1,516,633,001
38	Accounts Payable (232)		2,402,987,144	2,160,397,276
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		22,050,491	23,414,183
41	Customer Deposits (235)		231,822,866	231,954,935
42	Taxes Accrued (236)	262-263	433,396,782	147,023,038
43	Interest Accrued (237)		220,498,682	219,472,711
44	Dividends Declared (238)		2,319,386	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)		34,679,077	36,323,395
48	Miscellaneous Current and Accrued Liabilities (242)		692,014,936	509,678,150
49	Obligations Under Capital Leases-Current (243)		12,512,046	18,262,304
50	Derivative Instrument Liabilities (244)		88,095,705	127,287,589
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		57,007,082	88,887,394
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)		4,883,370,034	4,903,878,574
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		423,431,367	469,414,203
57	Accumulated Deferred Investment Tax Credits (255)	266-267	114,033,790	128,411,839
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	208,094,334	212,255,529
60	Other Regulatory Liabilities (254)	278	3,876,105,498	2,227,787,406
61	Unamortized Gain on Reaquired Debt (257)		862,920	1,008,945
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	307	307
63	Accum. Deferred Income Taxes-Other Property (282)		7,394,379,151	12,517,825,140
64	Accum. Deferred Income Taxes-Other (283)		448,217,063	711,929,333
65	Total Deferred Credits (lines 56 through 64)		12,465,124,430	16,268,632,702
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		64,105,225,466	65,775,410,504

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report End of 2017/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	17,477,273,258	17,837,520,495		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	9,354,586,213	10,017,207,909		
5	Maintenance Expenses (402)	320-323	1,473,178,225	1,578,146,187		
6	Depreciation Expense (403)	336-337	2,520,662,622	2,318,104,364		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	332,006,690	365,056,901		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		116,111			
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		-629,795	70,005,143		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	592,757,485	537,759,015		
15	Income Taxes - Federal (409.1)	262-263	-10,252,653	-102,414,099		
16	- Other (409.1)	262-263	108,797,147	-19,643,366		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	-208,874,972	483,365,700		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-718,959,065	139,214,264		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		13,324,707			
21	Losses from Disp. of Utility Plant (411.7)		270,691			
22	(Less) Gains from Disposition of Allowances (411.8)			2		
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)		14,868,252,122	15,108,373,488		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,609,021,136	2,729,147,007		

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
13,283,628,752	13,882,048,118	4,193,644,506	3,955,472,377			2
						3
7,014,966,243	8,010,497,695	2,339,619,970	2,006,710,214			4
959,259,070	852,668,218	513,919,155	725,477,969			5
1,980,795,695	1,844,735,417	539,866,927	473,368,947			6
						7
237,269,411	260,457,881	94,737,279	104,599,020			8
						9
116,111						10
						11
-629,795	70,005,143					12
						13
449,084,479	401,070,256	143,673,006	136,688,759			14
-10,252,653	-103,711,101		1,297,002			15
105,092,246	81,990,553	3,704,901	-101,633,919			16
-275,512,268	449,260,118	66,637,296	34,105,582			17
-713,495,770	22,523,442	-5,463,295	116,690,822			18
						19
2,517,330		10,807,377				20
270,691						21
	2					22
						23
						24
11,171,437,670	11,844,450,736	3,696,814,452	3,263,922,752			25
2,112,191,082	2,037,597,382	496,830,054	691,549,625			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	03/09/2018	End of 2017/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		2,609,021,136	2,729,147,007		
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	-3,103,044	49,093		
37	Interest and Dividend Income (419)		30,022,985	22,250,938		
38	Allowance for Other Funds Used During Construction (419.1)		89,256,337	112,488,153		
39	Miscellaneous Nonoperating Income (421)		5,679,371	38,384,882		
40	Gain on Disposition of Property (421.1)		6,657,171			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		128,512,820	173,173,066		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		10,944,162	12,965,525		
46	Life Insurance (426.2)					
47	Penalties (426.3)		24,386,884	33,144,344		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		13,443,474	11,340,945		
49	Other Deductions (426.5)		301,635,298	775,085,215		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		350,409,818	832,536,029		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	362,370	351,984		
53	Income Taxes-Federal (409.2)	262-263	71,582,687	49,511		
54	Income Taxes-Other (409.2)	262-263	-39,875,243	-18,424,592		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-40,539,809	6,702,261		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	158,562,363	135,763,621		
57	Investment Tax Credit Adj.-Net (411.5)		-14,378,049	-4,024,778		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-181,410,407	-151,109,235		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-40,486,591	-508,253,728		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		806,065,887	776,036,604		
63	Amort. of Debt Disc. and Expense (428)		27,416,689	28,859,372		
64	Amortization of Loss on Reaquired Debt (428.1)		18,399,376	20,530,674		
65	(Less) Amort. of Premium on Debt-Credit (429)		1,963,283	1,915,309		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		146,025	146,125		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		65,165,469	47,182,819		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		37,674,326	51,347,450		
70	Net Interest Charges (Total of lines 62 thru 69)		877,263,787	819,200,585		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,691,270,758	1,401,692,694		
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)		1,691,270,758	1,401,692,694		

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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

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

	2017		2016	
	Revenues	Expenses	Revenues	Expenses
Electric	44,421,522	71,545,053	44,898,176	66,448,741
Gas	189,093,175	161,969,644	162,540,914	140,990,349
Total	233,514,697	233,514,697	207,439,090	207,439,090

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

Refer to the footnote for Line 2, column c.

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	03/09/2018	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		8,576,546,935	8,095,695,738
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Cumulative effect of change in accounting principle			24,084,688
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			24,084,688
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		1,694,373,802	1,401,643,601
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	-23,778,373	(22,090,165)
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-23,778,373	(22,090,165)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25	Preferred Stock Dividends		-13,916,352	(13,916,354)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-13,916,352	(13,916,354)
30	Dividends Declared-Common Stock (Account 438)			
31				
32	Common Stock Dividends		-784,000,000	(911,000,000)
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-784,000,000	(911,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,387,061	2,129,427
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		9,450,613,073	8,576,546,935
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
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	03/09/2018	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41	Reserves for excess earnings on FERC hydroelectric			
42	project licenses pursuant to Federal Power Act Section 10 (d)		23,778,373	22,090,165
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		23,778,373	22,090,165
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		238,586,547	216,496,382
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		262,364,920	238,586,547
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		9,712,977,993	8,815,133,482
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-52,118,510	(50,038,177)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-3,103,044	49,093
51	(Less) Dividends Received (Debit)			
52	Utility subsidiary earnings reflected in operations and maintenance accounts		-1,387,061	(2,129,426)
53	Balance-End of Year (Total lines 49 thru 52)		-56,608,615	(52,118,510)

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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

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

Class of Stock	Annual No. of Shares	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.: 25 Column: d

The following is the detail of dividends declared on First Preferred Stocks for the year ended December 31, 2016:

Class of Stock	No. of Shares	Dividends Per Share	Total Declared
6.00% Cumulative, Non-Redeemable	4,211,662	$1.500	$ 6,317,512
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			$13,916,354

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

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

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, 2016.

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	03/09/2018	End of 2017/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	1,691,270,758	1,401,692,694
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	2,852,785,423	2,683,161,265
5	Disallowed Capital Expenditures	47,398,938	507,198,621
6	Amortization of Unamortized Loss or Gain on Reacquired Debt	17,613,914	25,843,827
7	Amortization of Expenses, Discount and Premium - Long Term Debt	18,098,551	9,406,456
8	Deferred Income Taxes (Net)	1,083,992,255	1,019,090,904
9	Investment Tax Credit Adjustment (Net)	-14,378,049	-4,024,778
10	Net (Increase) Decrease in Receivables	39,678,174	-1,044,170,612
11	Net (Increase) Decrease in Inventory	-16,973,849	-24,610,966
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	505,815,231	120,266,795
14	Net (Increase) Decrease in Other Regulatory Assets	-981,763,074	-854,099,084
15	Net Increase (Decrease) in Other Regulatory Liabilities	609,750,902	-287,473,741
16	(Less) Allowance for Other Funds Used During Construction	89,256,337	112,488,153
17	(Less) Undistributed Earnings from Subsidiary Companies	-4,490,105	9,215,527
18	Other (provide details in footnote):	129,518,306	889,235,922
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	5,898,041,248	4,319,813,623
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-5,596,719,659	-5,708,003,565
27	Gross Additions to Nuclear Fuel	-131,760,000	-113,641,852
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-89,256,337	-112,488,153
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-5,639,223,322	-5,709,157,264
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	25,953,577	12,907,267
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-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	2,116,947
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report End of 2017/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Net (Increase) Decrease in Restricted Cash	-186,641	227,547,523
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	1,291,749,504	1,295,192,896
55	Purchases of nuclear decommissioning trust investments and other	-1,322,693,283	-1,352,469,466
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-5,651,166,044	-5,523,862,097
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	2,713,526,928	983,900,644
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	-221,734,268	491,456,708
67	Other (provide details in footnote):		
68	Equity contribution from PG&E Corporation	455,000,000	835,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	2,946,792,660	2,310,357,352
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-1,445,000,000	-160,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Customer Advances for Construction	-7,963,753	31,687,898
78	Net Decrease in Short-Term Debt (c)	-500,000,000	
79	Other	-68,324,365	-41,715,147
80	Dividends on Preferred Stock	-13,916,352	-13,916,354
81	Dividends on Common Stock	-784,000,000	-911,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	127,588,190	1,215,413,749
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	374,463,394	11,365,275
87			
88	Cash and Cash Equivalents at Beginning of Period	68,401,200	57,035,925
89			
90	Cash and Cash Equivalents at End of period	442,864,594	68,401,200

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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

This consists of the following:

	2017	2016
Decrease in Other Working Capital	$ 105,668,533	$ 28,527,020
Increase (Decrease) - Other Noncurrent Liabilities	(191,024,518)	739,365,602
Others		
Nuclear Fuel Lease Amortization	123,258,253	125,349,148
Payment on capital lease obligation	(18,262,296)	(20,234,320)
Collateral Posted	(13,675,915)	44,312,983
Bad Debt Expense	54,533,182	50,486,925
Tax benefit on stock option exercises	24,464,196	4,805,641
Other-net	44,556,871	(83,377,077)
Total	$ 129,518,306	$ 889,235,922

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

See footnote in column (b), Line 18.

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

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

	2017	2016
Purchases of Nuclear Decommissioning Trust Investments	$ (1,322,771,298)	$ (1,352,474,365)
Decrease in other investments	78,015	4,899
Total	$ (1,322,693,283)	$ (1,352,469,466)

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:

	2017	2016
Increase (Decrease) in customer deposits	$ 469,325	$ (5,288,377)
Debt Issuance Costs - ST Borrowings	(3,268,176)	(1,853,073)
Employee taxes paid for withheld shares	(65,525,514)	(34,573,697)
Total	$ (68,324,365)	$ (41,715,147)

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

See footnote in column (b), Line 79.

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

This consists of the following:

	2017	2016
Cash (131)	$ 57,718,289	$ 68,255,295

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Working Funds (135)	146,305	145,905
Temporary Cash Investment (136)	385,000,000	-
Total	$ 442,864,594	$ 68,401,200

Supplemental disclosures of cash flow information (in millions):

Cash paid for:		
Interest (net of amounts capitalized)	$ (781)	$ (717)
Income taxes paid (refunded), net	162	244
Supplemental disclosures of noncash investing and financing activities:		
Capital expenditures financed through accounts payable	501	403
Terminated capital leases	23	18

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, 2017, as filed with the Securities and Exchange Commission ("SEC") on February 9, 2018. 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 negative balances 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, and (10) there is no current liability classification of the current portion of accumulated provision for injuries and damages for FERC reporting.

Subsequent Events:

Management has evaluated the impact of events occurring after December 31, 2017 up to February 9, 2018, 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 March 9, 2018. 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 $32,053,493 at December 31, 2017, 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 $204,601 for the year ended December 31, 2017, 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 $693 for the year ended December 31, 2017, of which $0 is recorded in account 582 and $693 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 $196,979 for the year ended December 31, 2017, of which $0 is recorded in account 570 and $196,979 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 $122.

Energy storage-related payroll tax expenses are recorded in account 408.1 in the amount of $43.

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	$11,197,000	$231	$58,976	$0	$204,601	$55
2	Hitachi	Distribution	San Jose, CA	$20,856,493	$231	$85,885	$0	$0	$55
3	Browns Valley	Distribution	Marysville, CA	$0	$231	$52,118	$0	$0	$55
Totals				**$32,053,493**	**$693**	**$196,979**	**$0**	**$204,601**	**$165**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: 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 regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation 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 impact on PG&E Corporation's and the Utility's financial condition and results of operations and cash flows during the period in which such change occurred.

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44. The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. See "Northern California Wildfires" in Note 13 below.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 also 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.

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

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.

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's ability to recover revenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. 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, revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

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. These differences have no impact on net income.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) 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 revenues subject to refund.

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:

	Estimated Useful	Balance at December 31,	
(in millions, except estimated useful lives)	**Lives (years)**	**2017**	**2016**
Electricity generating facilities (1)	5 to 120	$ 11,843	$ 11,308
Electricity distribution facilities	15 to 65	31,110	29,836
Electricity transmission facilities	15 to 75	12,180	11,412
Natural gas distribution facilities	5 to 60	12,312	11,362
Natural gas transmission and storage facilities	5 to 62	7,329	6,491
Construction work in progress		2,471	2,184
Total property, plant, and equipment		**77,245**	**72,593**
Accumulated depreciation		(23,456)	(22,012)
Net property, plant, and equipment		**$ 53,789**	**$ 50,581**

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as used based on the amount of energy output. (See Note 13 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 3.83% in 2017, 3.73% in 2016, and 3.80% in 2015. 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 $38 million and $89 million during 2017, $51 million and $112 million during 2016, and $48 million and $107 million during 2015.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2017 and 2016, including nuclear decommissioning obligations:

(in millions)	**2017**	**2016**
ARO liability at beginning of year	$ 4,684	$ 3,643
Revision in estimated cash flows	128	968
Accretion	207	194
Liabilities settled	(120)	(121)
ARO liability at end of year	**$ 4,899**	**$ 4,684**

The Utility has not recorded a liability related to certain ARO's 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 specified conditions under certain agreements.

Nuclear Decommissioning Obligation

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. On May 25, 2017, the CPUC issued a final decision in the 2015 NDCTP adopting a nuclear decommissioning cost estimate of $1.1 billion for Humboldt Bay, corresponding to the Utility's request, and $2.4 billion for Diablo Canyon, representing 64% of the Utility's request of $3.8 billion. On an aggregate basis, the final decision adopted a $3.5 billion total nuclear decommissioning cost estimate, compared to $4.8 billion requested by the Utility. Compared to the Utility's estimated cost to decommission Diablo Canyon, the final decision adopts assumptions which lower costs for large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility can seek recovery of these costs in the 2018 NDCTP. The CPUC's final decision resulted in a $66 million reduction to the ARO on the Consolidated Balance Sheets related to the assumed length of the wet cooling period of spent nuclear fuel after plant shut down.

PG&E Corporation and the Utility recorded an increase of $92 million to the ARO recognized on the Consolidated Balance Sheets, to align the decommissioning cost estimate with the CPUC's final decision on the Utility's application to retire Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $3.5 billion at both December 31, 2017 and 2016. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $4.1 billion at December 31, 2017 (or $7 billion in future dollars). These estimates are based on the 2017 decommissioning cost studies, prepared in accordance with CPUC requirements.

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 13 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 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, 2017, 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, 2017, 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 Note 13 herein.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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, 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.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2016 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
Beginning balance	$ (23)	$ 16	$ (7)
Other comprehensive income before reclassifications:			
Unrecognized prior service cost (net of taxes of $37 and $15, respectively)	54	(21)	33
Unrecognized net actuarial loss (net of taxes of $45 and $15, respectively)	(64)	21	(43)
Regulatory account transfer (net of taxes of $5 and $0, respectively)	7	-	7
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $3 and $6, respectively) [1]	5	9	14
Amortization of net actuarial loss (net of taxes of $10 and $2, respectively) [1]	14	2	16
Regulatory account transfer (net of taxes of $13 and $8, respectively) [1]	(18)	(11)	(29)
Net current period other comprehensive loss	**(2)**	**-**	**(2)**
Ending balance	**$ (25)**	**$ 16**	**$ (9)**

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

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Accounting Standards Issued But Not Yet Adopted

Presentation of Net Periodic Pension Cost

In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715)*, which amends the existing guidance relating to the presentation of net periodic pension cost and net periodic other post-retirement benefit costs. 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. In addition, on a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018. 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 actuaries. The change in capitalization of retirement benefits will not have a material impact on PG&E Corporation's and the Utility's Consolidated Financial Statements.

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which amends the existing guidance relating to the definition of a lease, recognition of lease assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. In November, 2017, the FASB tentatively decided to amend the new leasing guidance such that entities may elect not to restate their comparative periods in the period of adoption. Under the new standard, all lessees must recognize an asset and liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019, with early adoption permitted. PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility expect this standard to increase lease assets and lease liabilities on the Consolidated Balance Sheets and do not expect the guidance will have a material impact on the Consolidated Statements of Income, Statements of Cash Flows and lease disclosures.

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 existing 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. These investments are classified as "available-for-sale" and gains or losses are refundable, or recoverable, from customers through rates. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018 and will not have a material impact on the Consolidated Financial Statements and related disclosures.

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which amends existing 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. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018. This standard will be adopted for related disclosures in the first quarter of 2018 and will not have a material impact on the Consolidated Financial Statements. Upon adoption of ASU 2014-09, the Utility plans to disclose revenues from contracts with customers separately from regulatory balancing account revenue and disaggregate customer contract revenue by customer class.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Current Regulatory Assets

At December 31, 2017 and 2016, the Utility had current regulatory assets of $615 million and $423 million, respectively. At December 31, 2017 and 2016, the current regulatory assets included $426 million and $223 million, respectively, of costs related to CEMA fire prevention and vegetation management. Current regulatory assets are included within the current assets in the Consolidated Balance Sheets.

Long-Term Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Balance at December 31, 2017	2016	Recovery Period
Pension benefits (1)	$ 1,954	$ 2,429	Indefinitely (3)
Deferred income taxes (1)(4)	-	3,859	
Utility retained generation (2)	319	364	9 years
Environmental compliance costs (1)	837	778	32 years
Price risk management (1)	65	92	10 years
Unamortized loss, net of gain, on reacquired debt (1)	79	76	25 years
Other	539	353	Various
Total long-term regulatory assets	**$ 3,793**	**$ 7,951**	

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recognized in accordance with GAAP.

(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 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) 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.

(4) The change in the balance from a regulatory asset as of December 31, 2016 to a regulatory liability as of December 31, 2017 reflects the impact of changes in net deferred tax liabilities associated with a lower federal income tax rate as a result of the Tax Act. (See "Regulatory Liabilities" below and Note 8.)

At December 31, 2017 and 2016, other long-term regulatory assets included $274 million and $70 million, respectively, of costs related to CEMA events from 2014 through 2017 that the Utility believes are recoverable based on historical experience in recovering costs for these types of events.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation, and unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

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NOTES TO FINANCIAL STATEMENTS (Continued)

(in millions)	Balance at December 31, 2017	2016
Cost of removal obligations (1)	$ 5,547	$ 5,060
Deferred income taxes (2)	1,021	-
Recoveries in excess of AROs (3)	624	626
Public purpose programs (4)	590	567
Other	897	552
Total long-term regulatory liabilities	**$ 8,679**	**$ 6,805**

(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.

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:

(in millions)	Receivable Balance at December 31, 2017	2016
Electric distribution	$ -	$ 132
Electric transmission	139	244
Utility generation	-	48
Gas distribution and transmission	486	541
Energy procurement	71	132
Public purpose programs	103	106
Other	423	297
Total regulatory balancing accounts receivable	**$ 1,222**	**$ 1,500**

(in millions)	Payable Balance at December 31, 2017	2016
Electric distribution	$ 72	$ -
Electric transmission	120	99
Utility generation	14	-
Gas distribution and transmission	-	48
Energy procurement	149	13
Public purpose programs	452	264

Other	313	221
Total regulatory balancing accounts payable	**$ 1,120**	**$ 645**

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. 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

Long-Term Debt

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

		December 31,	
(in millions)		**2017**	**2016**
PG&E Corporation			
Senior notes:			
Maturity	Interest Rates		
2019	2.40%	$ 350	$ 350
Unamortized discount, net of premium and debt issuance costs		-	(2)
Total PG&E Corporation long-term debt		**350**	**348**
Utility			
Senior notes:			
Maturity	Interest Rates		
2017	5.63%	-	700
2018	8.25%	400	800
2020	3.50%	800	800
2021	3.25% to 4.25%	550	550
2022	2.45%	400	400
2023 through 2047	2.95% to 6.35%	14,975	12,375
Less: current portion (1)		(400)	(700)
Unamortized discount, net of premium and debt issuance costs		(185)	(161)
Total senior notes, net of current portion		**16,540**	**14,764**
Pollution control bonds:			
Maturity	Interest Rates		
Series 2004 A-D due 2023 (2)	4.75%	-	345
Series 2008 F and 2010 E, due 2026 (3)	1.75%	100	-
Series 2008 G, due 2018 (4)	1.05%	45	-
Series 2009 A-B, due 2026 (5)	1.78%	149	149
Series 1996 C, E, F, 1997 B due 2026 (6)	variable rate (7)	614	614
Less: current portion		(45)	-
Total pollution control bonds		**863**	**1,108**
Total Utility long-term debt, net of current portion		**17,403**	**15,872**
Total consolidated long-term debt, net of current portion		**$ 17,753**	**$ 16,220**

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NOTES TO FINANCIAL STATEMENTS (Continued)

(1) On January 19, 2018, the Utility sent a notice of redemption to redeem all $400 million aggregate principal amount of the 8.25% senior notes due October 15, 2018 on February 18, 2018. On January 31, 2018, the Utility deposited with the trustee funds sufficient to effect the early redemption of these bonds and satisfy and discharge its remaining obligation of $400 million.

(2) In June 2017, the Utility repurchased and retired $345 million principal amount of Pollution Control Bonds series 2004 A-D.

(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 30, 2022.

(4) Pollution Control Bonds series 2008G were remarketed and issued in June 2017 and mature on December 1, 2018.

(5) 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.

(6) Each series of these bonds is supported by a separate letter of credit. In December 2015, 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.

(7) At December 31, 2017, the interest rate on these bonds ranged from 1.45% - 1.70%.

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 combined long-term debt principal repayment amounts at December 31, 2017 are reflected in the table below:

(in millions, except interest rates)	2018	2019	2020	2021	2022	Thereafter	Total
PG&E Corporation							
Average fixed interest rate	-	2.40%	-	-	-	-	2.40%
Fixed rate obligations	$ -	$ 350	$ -	$ -	$ -	$ -	$ 350
Utility							
Average fixed interest rate	7.52%	-	3.50%	3.80%	2.31%	4.68%	4.61%
Fixed rate obligations	$ 445	$ -	$ 800	$ 550	$ 500 (2)	$ 14,975	$ 17,270
Variable interest rate as of December 31, 2017	-	1.78%	1.59%	-	-	-	1.63%
Variable rate obligations (1)	$ -	$ 149	$ 614	$ -	$ -	$ -	$ 763
Total consolidated debt	**$ 445**	**$ 499**	**$ 1,414**	**$ 550**	**$ 500**	**$ 14,975**	**$ 18,383**

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

(2) 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 30, 2022.

Short-term Borrowings

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at December 31, 2017:

	Termination	Credit Facility	Letters of Credit	Commercial Paper	Facility

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NOTES TO FINANCIAL STATEMENTS (Continued)

(in millions)	Date	Limit		Outstanding	Outstanding	Availability
PG&E Corporation	April 2022	$ 300	(1)	$ -	$ 132	$ 168
Utility	April 2022	3,000	(2)	49	50	2,901
Total revolving credit facilities		**$ 3,300**		**$ 49**	**$ 182**	**$ 3,069**

(1) Includes a $50 million lender commitment to the letter of credit sublimit 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 sublimit and a $75 million commitment for swingline loans.

For the year ended December 31, 2017, PG&E Corporation's average outstanding commercial paper balance was $81 million and the maximum outstanding balance during the year was $161 million. For 2017, the Utility's average outstanding commercial paper balance was $469 million and the maximum outstanding balance during the year was $1.1 billion. There were no bank borrowings for PG&E Corporation or the Utility in 2017.

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. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes.

Borrowings under each credit agreement (other than swingline loans) will bear interest based on the borrower's credit rating and on each borrower's election of either (1) a London Interbank Offered Rate ("LIBOR") plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal 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 will determine the applicable rate within the following ranges. The applicable margin for LIBOR loans will range 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 will range 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 will range 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 require 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 requires that PG&E Corporation owns, 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 are used primarily to fund temporary financing needs. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation's and the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. For 2017, the average yield on outstanding PG&E Corporation and Utility commercial paper was 1.29% and 1.11%, respectively.

Other Short-term Borrowings

In February 2017, the Utility's $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid. Additionally, in February 2017, the Utility entered into a $250 million floating rate unsecured term loan maturing on February 22, 2018. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

In November 2017, the Utility issued $500 million in unsecured floating rate senior notes that mature on November 28, 2018. The proceeds were used towards repayment of the $250 million unsecured floating rate senior notes due November 30, 2017 and the balance was used to support the Northern California wildfire response efforts.

NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 514,755,845 shares of common stock outstanding at December 31, 2017. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2017.

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate price of up to $275 million. During 2017, PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $28.4 million, net of commissions paid of $0.2 million. There were no issuances under the February 2017 EDA for the three months ended December 31, 2017. As of December 31, 2017, the remaining sales available under this agreement were $246.3 million.

In addition, during 2017, PG&E Corporation sold 7.4 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 $366.4 million.

Dividends

Ordinarily, the Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. 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 $218 million of the Utility's retained earnings was subject to this restriction at December 31, 2017. 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, $14.3 billion of the Utility's net assets were restricted at December 31, 2017. Additionally, as a result of this requirement, the Utility's ability to pay dividends in the future could be impacted by future potential liabilities. On December 20, 2017, the Board of Directors of PG&E Corporation suspended quarterly cash dividends on PG&E Corporation's common stock, beginning with the fourth quarter of 2017 due to uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See "Northern California Wildfires" in Note 13 below.)

For the first quarter of 2017, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share quarterly. In May 2017, the Board of Directors of PG&E Corporation approved a new annual common stock cash dividend of $0.53 per share quarterly. In 2017, total dividends declared were $1.55 per share.

Long-Term Incentive Plan

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, 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 14,327,157 shares were available for future awards at December 31, 2017.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2017, 2016, and 2015:

(in millions)	2017	2016	2015
Restricted stock units	$ 40	$ 53	$ 47
Performance shares	45	55	46
Total compensation expense (pre-tax)	**$ 85**	**$ 108**	**$ 93**
Total compensation expense (after-tax)	**$ 50**	**$ 64**	**$ 55**

The amount of share-based compensation costs capitalized during 2017, 2016, and 2015 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Restricted Stock Units

Restricted stock units 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 rateably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2017, 2016, and 2015 was $66.95, $56.68, and $53.30, respectively. The total fair value of restricted stock units that vested during 2017, 2016, and 2015 was $57 million, $36 million, and $57 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2017, $33 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.46 years.

The following table summarizes restricted stock unit activity for 2017:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,923,010	$ 51.26
Granted	658,395	66.95
Vested	(1,172,194)	48.44
Forfeited	(29,976)	61.07
Nonvested at December 31	**1,379,235**	$ 60.93

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 rateably 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 2017, 2016, and 2015 was $77.00, $53.61, and $68.27, respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2017, $46 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.42 years.

The following table summarizes activity for performance shares in 2017:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value

Nonvested at January 1	1,838,855	$ 58.65
Granted	745,724	77.00
Vested	(81,501)	53.74
Forfeited (1)	(755,050)	66.30
Nonvested at December 31	**1,748,028**	$ 63.40

(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, 2017 and December 31, 2016, 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, 2017, 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, 2017, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility determined to suspend quarterly cash dividends on the Utility's preferred stock, beginning with the three-month period ending January 31, 2018, due to uncertainty related to causes and potential liabilities associated with the October 2017 Northern California wildfires. See "Northern California Wildfires" in Note 13 below.)

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 $14 million of dividends on preferred stock in each of 2017, 2016, and 2015.

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 2017, 2016, and 2015.

	Year Ended December 31,		
(in millions, except per share amounts)	**2017**	**2016**	**2015**
Income available for common shareholders	$ 1,646	$ 1,393	$ 874
Weighted average common shares outstanding, basic	512	499	484
Add incremental shares from assumed conversions:			
Employee share-based compensation	1	2	3
Weighted average common share outstanding, diluted	513	501	487
Total earnings per common share, diluted	**$ 3.21**	**$ 2.78**	**$ 1.79**

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)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Current:						
Federal	$ (10)	$ (105)	$ (89)	$ 61	$ (105)	$ (88)
State	48	(70)	11	50	(66)	6
Deferred:						
Federal	481	218	131	326	229	136
State	6	16	(76)	4	16	(69)
Tax credits	(14)	(4)	(4)	(14)	(4)	(4)
Income tax provision (benefit)	**$ 511**	**$ 55**	**$ (27)**	**$ 427**	**$ 70**	**$ (19)**

The following table describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	**2017**	**2016**	**2017**	**2016**
Deferred income tax assets:				
Tax carryforwards	830	1,851	736	1,596
Compensation	274	277	205	199
Income tax regulatory liability (1)	286	-	286	-
Other (2)	185	186	194	203
Total deferred income tax assets	**$ 1,575**	**$ 2,314**	**$ 1,421**	**$ 1,998**

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Deferred income tax liabilities:				
Property related basis differences	7,269	10,429	7,256	10,411
Income tax regulatory asset (1)	-	1,572	-	1,572
Other (3)	128	526	128	525
Total deferred income tax liabilities	**$ 7,397**	**$ 12,527**	**$ 7,384**	**$ 12,508**
Total net deferred income tax liabilities	**$ 5,822**	**$ 10,213**	**$ 5,963**	**$ 10,510**

(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 and "Tax Cuts and Jobs Act of 2017" below.)

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

(3) 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,					
	2017	2016	2015	2017	2016	2015
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	1.5	(2.5)	(4.9)	1.6	(2.2)	(4.8)
Effect of regulatory treatment of fixed asset differences (2)	(16.5)	(23.7)	(33.6)	(16.8)	(23.4)	(33.7)
Tax credits	(1.1)	(0.8)	(1.3)	(1.1)	(0.8)	(1.3)
Benefit of loss carryback	-	(1.1)	(1.5)	-	(1.1)	(1.5)
Non deductible penalties (3)	0.4	0.8	4.3	0.4	0.8	4.3
Tax Reform Adjustment (4)	6.8	-	-	3.0	-	-
Other, net (5)	(2.5)	(3.9)	(1.1)	(2.0)	(3.5)	(0.2)
Effective tax rate	**23.6 %**	**3.8 %**	**(3.1) %**	**20.1 %**	**4.8 %**	**(2.2) %**

(1) Includes the effect of state flow-through ratemaking treatment. In 2016 and 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions. The 2017 amount reflects an agreement with the IRS on a 2013 audit related to generation repairs deductions.

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted 2016 and 2017. All amounts are impacted by the level of income before income taxes. The 2014 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.

(3) Primarily represents the effects of a non-tax deductible penalty associated with the Butte fire for 2017, non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for 2016 and the effects of the San Bruno Penalty Decision for 2015.

(4) Represents the required adjustment to deferred tax balances, due to the federal income tax rate being lowered from 35% to 21% beginning in 2018 as a result of the enactment of the Tax Act.

(5) These amounts primarily represent 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)	2017	2016	2015	2017	2016	2015
Balance at beginning of year	$ 388	$ 468	$ 713	$ 382	$ 462	$ 707
Additions for tax position taken during a prior year	-	-	40	-	-	40
Reductions for tax position taken during a prior year	(71)	(77)	(349)	(71)	(77)	(349)
Additions for tax position taken during the current year	48	56	64	48	56	64
Settlements	(14)	(59)	-	(8)	(59)	-
Expiration of statute	(3)	-	-	(3)	-	-
Balance at end of year	**$ 349**	**$ 388**	**$ 468**	**$ 349**	**$ 382**	**$ 462**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2017 for PG&E Corporation and the Utility was $21 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, 2017, it is reasonably possible that unrecognized tax benefits will decrease by approximately $20 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, 2017, 2016, and 2015, 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 percent to 21 percent beginning on January 1, 2018 and eliminated bonus depreciation for utilities. The Tax Act required PG&E Corporation and the Utility to re-measure all existing deferred income tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility have made reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by the SEC in Staff Accounting Bulletin No. 118, for the re-measurement of deferred tax balances as of December 31, 2017.

During the three months and year ended December 31, 2017, PG&E Corporation, on a consolidated basis, recorded a one-time provisional tax expense of $147 million to reflect the transitional impacts of the Tax Act. Of this amount, $83 million is attributable to the re-measurement of PG&E Corporation's net deferred tax asset comprised primarily of net operating loss carry-forwards and compensation-related items. The remaining $64 million is related to the re-measurement of the Utility's deferred taxes not reflected in authorized revenue requirements, such as disallowed plant. The Utility also recorded a provisional $5.7 billion re-measurement of its deferred tax balances (related to flow-through and normalized timing differences for plant-related items) which was offset by a change from a net deferred income tax regulatory asset to a net regulatory liability. The deferred income tax regulatory liability will be refunded to customers over the regulatory lives of the related assets.

The final transition impacts of the Tax Act may differ from the above recorded amounts, possibly materially, due to, among other things, regulatory decisions from the CPUC that could differ from the Utility's determination of how the impacts of the Tax Act are allocated between customers and shareholders. In addition, while PG&E Corporation and the Utility were able to make reasonable estimates of the impact of the reduction in federal tax rate and the elimination of bonus depreciation due to the enactment of the Tax Act; changes in interpretations, guidance on legislative intent, and any changes in accounting standards for income taxes in response to the Tax Act could impact the recorded amounts. PG&E Corporation and the Utility will finalize and record any adjustments related to the Tax Act within the one year measurement period provided under Staff Accounting Bulletin No. 118.

Tax Settlements

PG&E Corporation's tax returns have been accepted through 2015 except for a few matters, the most significant of which relates to deductible repair costs for gas transmission and distribution lines of business. 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. The IRS may issue guidance in 2018 that clarifies which repair costs are deductible for the natural gas transmission and distribution lines of business.

Tax years after 2008 remain subject to examination by the state of California.

2015 Gas Transmission and Storage Rate Case

The final phase two decision reduced rate base by the full amount of the disallowed capital expenditures but did not remove the associated deferred taxes, which the Utility believes constitutes a normalization violation. In the final decision, the CPUC authorized the Utility to establish a Tax Normalization Memorandum Account to track relevant costs and clarified that it is the CPUC's intention that the Utility comply with normalization rules and avoid the potential adverse consequences of a normalization violation. The CPUC allowed the Utility to seek a ruling from the IRS and the Utility filed the ruling request with the IRS on April 10, 2017. On October 5, 2017, the IRS issued a private letter ruling indicating the final decision rate base reduction was inconsistent with the IRS tax normalization requirements. As a result of the IRS private letter ruling, the Utility filed an advice letter with the CPUC on December 11, 2017, requesting a rate base adjustment of $7 million, $28 million, $49 million, and $61 million, in 2015, 2016, 2017, and 2018, respectively.

Carryforwards

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

(in millions)	December 31, 2017	Expiration Year
Federal:		
Net operating loss carryforward	$ 4,233	2031 - 2036
Tax credit carryforward	103	2029 - 2036
Charitable contribution loss carryforward	93	2019 - 2021
State:		
Net operating loss carryforward	$ -	N/A
Tax credit carryforward	13	Various
Charitable contribution loss carryforward	24	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, 2017 for these tax attributes.

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.

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 counterparty. 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 activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. These 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. Eligible derivatives are accounted for under the accrual method of accounting.

Volume of Derivative Activity

At December 31, 2017 and 2016, respectively, the volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume	
Underlying Product	**Instruments**	**2017**	**2016**
Natural Gas(1) (MMBtus(2))	Forwards and Swaps	228,768,745	323,301,331
	Options	60,736,806	96,602,785
Electricity (Megawatt-hours)	Forwards and Swaps	2,872,013	3,287,397
	Congestion Revenue Rights(3)	312,272,177	278,143,281

(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, 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**

At December 31, 2016, 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	$ 91	$ (10)	$ 1	**$ 82**
Other noncurrent assets – other	149	(9)	-	**140**

Current liabilities – other	(48)	10	-	**(38)**
Noncurrent liabilities – other	(101)	9	3	**(89)**
Total commodity risk	**$ 91**	**$ -**	**$ 4**	**$ 95**

Gains and losses associated with price risk management activities were recorded as follows:

	Commodity Risk		
	For the year ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Unrealized gain/(loss) - regulatory assets and liabilities[1]	$ (71)	$ 64	$ (6)
Realized loss - cost of electricity[2]	(27)	(53)	(14)
Realized loss - cost of natural gas[2]	(5)	(18)	(10)
Total commodity risk	**$ (103)**	**$ (7)**	**$ (30)**

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.

[2] These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

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 contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2017, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

	Balance at December 31,	
(in millions)	**2017**	**2016**
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (1)	$ (24)
Related derivatives in an asset position	-	19
Collateral posting in the normal course of business related to these derivatives	-	4
Net position of derivative contracts/additional collateral posting requirements[1]	**$ (1)**	**$ (1)**

[1] This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

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.

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	03/09/2018	2017/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 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.

	Fair Value Measurements At December 31, 2016				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	$ 105	$ -	$ -	$ -	**$ 105**
Nuclear decommissioning trusts					
Short-term investments	9	-	-	-	**9**
Global equity securities	1,724	-	-	-	**1,724**
Fixed-income securities	665	527	-	-	**1,192**

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Assets measured at NAV	-	-	-	-	**14**
Total nuclear decommissioning trusts (2)	**2,398**	**527**	**-**	**-**	**2,939**
Price risk management instruments (Note 9)					
Electricity	30	18	181	(18)	**211**
Gas	-	11	-	-	**11**
Total price risk management instruments	**30**	**29**	**181**	**(18)**	**222**
Rabbi trusts					
Fixed-income securities	-	61	-	-	**61**
Life insurance contracts	-	70	-	-	**70**
Total rabbi trusts	**-**	**131**	**-**	**-**	**131**
Long-term disability trust					
Short-term investments	8	-	-	-	**8**
Assets measured at NAV	-	-	-	-	**170**
Total long-term disability trust	**8**	**-**	**-**	**-**	**178**
TOTAL ASSETS	**$ 2,541**	**$ 687**	**$ 181**	**$ (18)**	**$ 3,575**
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	$ 9	$ 12	$ 126	$ (21)	**$ 126**
Gas	-	2	-	(1)	**1**
TOTAL LIABILITIES	**$ 9**	**$ 14**	**$ 126**	**$ (22)**	**$ 127**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $333 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, 2017 and 2016.

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 and over-the-counter 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, 2017		Valuation	Unobservable	
Fair Value Measurement	**Assets**	**Liabilities**	**Technique**	**Input**	**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

(in millions)	Fair Value at At December 31, 2016		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$ 181	$ 35	Market approach	CRR auction prices	$ (11.88) - 6.93
Power purchase agreements	$ -	$ 91	Discounted cash flow	Forward prices	$ 18.07 - 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, 2017 and 2016, respectively:

	Price Risk Management Instruments	
(in millions)	**2017**	**2016**
Asset (liability) balance as of January 1	**$ 55**	**$ 89**
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(13)	(34)
Asset (liability) balance as of December 31	**$ 42**	**$ 55**

(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, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2017 and 2016, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2017 and 2016.

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

	At December 31,			
	2017		2016	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
Debt (Note 4)				
PG&E Corporation	$ 350	$ 350	$ 348	$ 352
Utility	17,090	19,128	15,813	17,790

Available for Sale Investments

The following table provides a summary of available-for-sale investments:

(in millions)	**Amortized Cost**	**Total Unrealized Gains**	**Total Unrealized Losses**	**Total Fair Value**
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**
As of December 31, 2016				
Nuclear decommissioning trusts				
Short-term investments	$ 9	$ -	$ -	$ 9
Global equity securities	584	1,157	(3)	1,738
Fixed-income securities	1,156	48	(12)	1,192
Total (1)	**$ 1,749**	**$ 1,205**	**$ (15)**	**$ 2,939**

(1) Represents amounts before deducting $440 million and $333 million at December 31, 2017 and 2016, 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, 2017**
Less than 1 year	$ 41
1–5 years	414
5–10 years	352
More than 10 years	488
Total maturities of fixed-income securities	**$ 1,295**

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

(in millions)	**2017**	**2016**	**2015**
Proceeds from sales and maturities of nuclear decommissioning investments	$ 1,291	$ 1,295	$ 1,268
Gross realized gains on securities held as available-for-sale	53	18	55
Gross realized losses on securities held as available-for-sale	(11)	(26)	(37)

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"). The trusts underlying certain of 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. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans is zero.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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 2017 and 2016:

Pension Plan

(in millions)	**2017**	**2016**
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 14,729**	**$ 13,745**
Actual return on plan assets	2,380	1,358
Company contributions	335	334
Benefits and expenses paid	(792)	(708)
Fair value of plan assets at end of year	**$ 16,652**	**$ 14,729**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 17,305**	**$ 16,299**
Service cost for benefits earned	472	453
Interest cost	714	715
Actuarial (gain) loss	1,048	637
Plan amendments	10	(91)
Benefits and expenses paid	(792)	(708)
Benefit obligation at end of year (1)	**$ 18,757**	**$ 17,305**
Funded Status:		
Current liability	$ (7)	$ (7)
Noncurrent liability	(2,098)	(2,569)
Net liability at end of year	**$ (2,105)**	**$ (2,576)**

(1) PG&E Corporation's accumulated benefit obligation was $16.8 billion and $15.6 billion at December 31, 2017 and 2016, respectively.

Postretirement Benefits Other than Pensions

(in millions)	**2017**	**2016**
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,173**	**$ 2,035**
Actual return on plan assets	298	167
Company contributions	33	52
Plan participant contribution	87	85
Benefits and expenses paid	(171)	(166)
Fair value of plan assets at end of year	**$ 2,420**	**$ 2,173**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,877**	**$ 1,766**
Service cost for benefits earned	59	52
Interest cost	77	76
Actuarial (gain) loss	(49)	11
Plan amendments	-	37

Benefits and expenses paid	(157)	(153)
Federal subsidy on benefits paid	3	3
Plan participant contributions	87	85
Benefit obligation at end of year	**$ 1,897**	**$ 1,877**
Funded Status: (1)		
Noncurrent asset	$ 553	$ 368
Noncurrent liability	(30)	(72)
Net asset at end of year	**$ 523**	**$ 296**

(1) At December 31, 2017 and 2016, 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

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

Pension Plan

(in millions)	**2017**	**2016**	**2015**
Service cost	$ 472	$ 453	$ 479
Interest cost	714	715	673
Expected return on plan assets	(770)	(828)	(873)
Amortization of prior service cost	(7)	8	15
Amortization of net actuarial loss	22	24	10
Net periodic benefit cost	**431**	**372**	**304**
Less: transfer to regulatory account (1)	(92)	(34)	34
Total expense recognized	**$ 339**	**$ 338**	**$ 338**

(1) 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)	**2017**	**2016**	**2015**
Service cost	$ 59	$ 52	$ 55
Interest cost	77	76	71
Expected return on plan assets	(97)	(107)	(112)
Amortization of prior service cost	15	15	19
Amortization of net actuarial loss	4	4	4
Net periodic benefit cost	**$ 58**	**$ 40**	**$ 37**

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 2018 are as follows:

(in millions)	**Pension Plan**	**PBOP Plans**
Unrecognized prior service cost	$ (6)	$ 14
Unrecognized net loss	5	(5)
Total	**$ (1)**	**$ 9**

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,**					
	2017		**2016**		**2015**		**2017**		**2016**		**2015**	
Discount rate	3.64	%	4.11	%	4.37	%	3.60- 3.67	%	4.05 - 4.19	%	4.27 - 4.48	%
Rate of future compensation increases	3.90	%	4.00	%	4.00	%	-		-		-	
Expected return on plan assets	6.20	%	5.30	%	6.10	%	3.30 - 7.10	%	2.80 - 6.00	%	3.20 - 6.60	%

The assumed health care cost trend rate as of December 31, 2017 was 6.8%, decreasing gradually to an ultimate trend rate in 2025 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	$ 128	$ (129)
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 6.2% compares to a ten-year actual return of 7.8%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 623 Aa-grade non-callable bonds at December 31, 2017. 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, and global listed infrastructure equities. 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		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Global equity	29 %	27 %	25 %	33 %	32 %	32 %
Absolute return	5 %	5 %	5 %	3 %	3 %	3 %
Real assets	8 %	10 %	10 %	6 %	7 %	7 %
Fixed income	58 %	58 %	60 %	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, 2017 and 2016.

	Fair Value Measurements At December 31,							
	2017				2016			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Pension Plan:								
Short-term investments	$ 287	$ 424	$ -	**$ 711**	$ 364	$ 369	$ -	**$ 733**
Global equity	1,292	-	-	**1,292**	996	-	-	**996**
Real assets	499	-	-	**499**	610	-	-	**610**
Fixed-income	1,916	5,520	4	**7,440**	1,754	4,774	5	**6,533**
Assets measured at NAV	-	-	-	**6,818**	-	-	-	**5,950**
Total	**$ 3,994**	**$ 5,944**	**$ 4**	**$ 16,760**	**$ 3,724**	**$ 5,143**	**$ 5**	**$ 14,822**
PBOP Plans:								
Short-term investments	$ 31	$ -	$ -	**$ 31**	$ 33	$ -	$ -	**$ 33**
Global equity	141	-	-	**141**	115	-	-	**115**
Real assets	55	-	-	**55**	70	-	-	**70**
Fixed-income	163	757	-	**920**	150	656	-	**806**
Assets measured at NAV	-	-	-	**1,281**	-	-	-	**1,153**
Total	**$ 390**	**$ 757**	**$ -**	**$ 2,428**	**$ 368**	**$ 656**	**$ -**	**$ 2,177**
Total plan assets at fair value				**$ 19,188**				**$ 16,999**

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $116 million and $97 million at December 31, 2017 and 2016, 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 NAV 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

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 and global listed infrastructure equities. 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

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, 2017 and 2016.

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, 2017 and 2016:

(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**

(in millions) **For the year ended December 31, 2016**	**Fixed-Income**
Balance at beginning of year	$ 3
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	-
Settlements	(1)
Balance at end of year	**$ 5**

There were no material transfers out of Level 3 in 2017 and 2016.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $335 million to the pension benefit plans and $33 million to the other benefit plans in 2017. 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 2017. The Utility's pension benefits met all the funding requirements under the 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 2018.

Benefits Payments and Receipts

As of December 31, 2017, 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
2018	$ 712	$ 83	$ (8)
2019	811	87	(9)
2020	850	91	(9)
2021	886	95	(10)
2022	920	100	(3)
Thereafter in the succeeding five years	5,002	508	(15)

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 $103 million, $97 million, and $89 million in 2017, 2016, and 2015, 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)	**2017**	**2016**	**2015**
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 8	$ 7	$ 6
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 65	$ 74	$ 53
Utility employee benefit due to PG&E Corporation	73	91	82

At December 31, 2017 and 2016, the Utility had receivables of $20 million and $18 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 $22 million and $22 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 13: 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 provision for loss and expense excludes anticipated legal costs, which are expensed 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, and cash flows may be materially affected by the outcome of the following matters.

Enforcement and Litigation Matters

Northern California Wildfires

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City. According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The Utility incurred $219 million in costs for service restoration and repair to the Utility's facilities (including $97 million in capital expenditures) through December 31, 2017 in connection with these fires. While the Utility believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs.

The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. The CPUC's SED also 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. (For example, on February 3, 2018, it was reported that investigators with the Santa Rosa Fire Department had completed their investigation of two small fires that reportedly destroyed two homes and damaged one outbuilding and had concluded that the Utility's facilities, along with high wind and other factors, contributed to those fires.) It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

As of January 31, 2018, the Utility had submitted 22 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire 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. The investigations into the fires are ongoing.

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. 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 benefitted from such undertaking and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost recovery even if a court decision were to determine that the doctrine of inverse condemnation applies. In addition to such claims for property damage, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.

Given the preliminary stages of investigations and the uncertainty as to the causes of the fires, PG&E Corporation and the Utility do not believe a loss is probable at this time. However, it is reasonably possible that facts could emerge through the course of the various investigations that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in an accrued liability in the future, the amount of which could be material. PG&E Corporation and the Utility currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur given the preliminary stages of the investigations and the uncertainty regarding the extent and magnitude of potential damages. On January 31, 2018, the California Department of Insurance issued a press release announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion estimated in respect of the wildfires that occurred in October 2017, depending on the extent of the damage in connection with such fire or fires. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

As of January 31, 2018, PG&E Corporation and the Utility are aware of 111 lawsuits, six of which seek to be certified as class actions, that have been filed against PG&E Corporation and the Utility in the Sonoma, Napa and San Francisco Counties Superior Courts. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They 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 fires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, insurance carriers who have made payments to their insureds for property damage arising out of the fires have filed three subrogation complaints in the San Francisco County Superior Court. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. On October 31, 2017, a group of plaintiffs submitted a petition for coordination to the Chair of the Judicial Council of California and requested coordination of the litigation in the San Francisco Superior Court. On November 9, 2017, PG&E Corporation and the Utility submitted a petition for coordination to the Chair of the Judicial Council of California, and requested separate coordination in the counties in which the fires occurred. On January 4, 2018, the coordination motion judge of the San Francisco Superior Court entered an order granting coordination of the litigation in connection with the Northern California wildfires and recommending that the coordinated proceeding take place in the San Francisco Superior Court. On January 12, 2018, the Judicial Council of California accepted the coordination motion judge's recommendation and assigned the coordinated proceeding to San Francisco. The first case management conference is scheduled for February 27, 2018.

In addition, two derivative lawsuits 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. The first lawsuit is filed against the members of the Board of Directors and certain officers of PG&E Corporation. PG&E Corporation is identified as a nominal defendant in that action. The second lawsuit is filed against the members of the Board of Directors, certain former members of the Board of Directors, and certain officers of both PG&E Corporation and the Utility. PG&E Corporation and the Utility are identified as nominal defendants in that action. Motions to consolidate the two lawsuits, appoint lead plaintiffs' counsel, and enter a case schedule are currently pending.

PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $800 million. If the Utility were to be found liable for one or more fires, the Utility's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires. Following the Northern California wildfires, PG&E Corporation reinstated its liability insurance in the amount of approximately $630 million for any potential future event.

In addition, it could take a number of years before the Utility's final liability is known and the Utility could apply for cost recovery. The Utility may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. Further, SB 819, introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities from recovering costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the utility did not reasonably construct, maintain, manage, control, or operate the facilities. PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Litigation and Regulatory Citations in Connection with the Butte Fire

In September 2015, a wildfire (known as the "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 wildfire. According to Cal Fire's report, the 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 wildfire 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 for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 31, 2017, 77 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 3,770 individual plaintiffs representing approximately 2,030 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. 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. As of December 31, 2017, several plaintiffs have dismissed the Utility's two vegetation management contractors. The number of individual complaints and plaintiffs may still increase in the future, because the statute of limitations for property damages in connection with the Butte fire has not yet expired. (The statute of limitations for personal injury in connection with the Butte fire has expired.) The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint with the Superior Court of the State of California, County of Calaveras, seeking to recover $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Tree's, Inc., one of the Utility's vegetation contractors. The Utility and Cal Fire are currently engaged in a mediation process.

Further, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $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 Butte fire. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million. This claim would include costs that the County of Calaveras incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire.

On April 28, 2017, the Utility moved for summary adjudication on plaintiffs' claims for punitive damages. On August 10, 2017, the Court denied the Utility's motion on the grounds that plaintiffs might be able to show conscious disregard for public safety based on the fact that the Utility relied on contractors to fulfill their contractual obligation to hire and train qualified employees. On August 16, 2017, the Utility filed a writ with the Court of Appeals challenging what the Utility believes is a novel theory of punitive damages liability. The Court of Appeals accepted the writ on September 15, 2017 and ordered the trial court and plaintiffs to show cause why the relief requested by the Utility should not be granted. Briefing on the writ was completed as of January 2, 2018. The Utility is seeking expedited review of the motion.

On June 22, 2017, the Superior Court for the 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 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, others could file lawsuits and 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. The motion is set for hearing on March 15, 2018.

Estimated Losses from Third-Party Claims

In connection with this matter, the Utility may be liable for property damages, 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 were found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court or jury would agree with the Utility.

The Utility currently believes that it is probable that it will incur a loss of at least $1.1 billion, increased from the $750 million previously estimated as of December 31, 2016, in connection with the Butte fire. The Utility's updated estimate resulted primarily from an increase in the number of claims filed against the Utility and experience to date in resolving claims. This amount is based on updated 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, but does not include punitive damages for which the Utility could be liable. In addition, 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 significant portion of the estimated claims from the OES and the County of Calaveras. The Utility still does not have sufficient information to reasonably estimate the probable loss it may have for these additional claims.

The Utility currently is unable to reasonably estimate the upper end of the range of losses due to the uncertainty of pending legal motions related to the applicability of inverse condemnation and punitive damages and because it has insufficient information on the claims of over 1,000 households and the claims from the OES and the County of Calaveras. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs, results from the ongoing mediation and settlement process, review of potential claims from the OES and the County of Calaveras, outcomes of future court or jury decisions, and information about damages, including punitive damages, that the Utility could be liable for, management estimates and assumptions regarding the financial impact of the 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 Other current liabilities 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**

[1] As of December 31, 2017 the Utility entered into settlement agreements in connection with the Butte fire corresponding to approximately $624 million of which $539 million has been paid by the Utility.

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $87 million in connection with the Butte fire. For the year ended December 31, 2017, the Utility has incurred legal expenses in connection with the Butte fire of $60 million.

Loss Recoveries

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the 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, 2017, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the 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, in the year ended December 31, 2017, the Utility received $53 million of reimbursements from the insurance policies of one of its vegetation management contractors (excluded from the table below). 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**

In January 2018, the Utility received another $75 million in insurance reimbursements.

If the Utility records losses in connection with claims relating to the 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, or cash flows could be materially affected in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals.

Regulatory Citations

On April 25, 2017, the SED issued two citations to the Utility in connection with the Butte fire, totaling $8.3 million. The SED's investigation found that neither the Utility nor its vegetation management contractors took appropriate steps to prevent the gray pine from leaning and contacting the Utility's electric line, which created an unsafe and dangerous condition that resulted in that tree leaning and making contact with the electric line, thus causing a fire. The Utility paid the citations in June 2017.

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 as a result of these investigations.

CPUC Matters

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 or a commissioner's advisor 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 March, 28, 2017, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility jointly submitted to the CPUC a settlement agreement in connection with the OII into the Utility's compliance with the CPUC's ex parte communication rules. On September 1, 2017, the assigned administrative law judge issued a PD in this proceeding adopting, with one modification, the settlement agreement jointly submitted to the CPUC on March 28, 2017, by the Utility, the Cities of San Bruno and San Carlos, the ORA, the SED, and TURN.

If adopted, the PD would increase the payment to the California General Fund, relative to the settlement agreement, from $1 million to $12 million resulting 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 GRC following the 2017 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.

On September 21, 2017, the Utility submitted a motion to the CPUC accepting the proposed modification of the settlement agreement to increase the Utility's payment to the California General Fund from $1 million to $12 million. Further, the Utility also reported that it has identified several communications that appear to raise issues similar to other communications that are part of this proceeding.

On November 1, 2017, the Utility filed a status report advising the CPUC that the Utility and the non-Utility parties to the settlement agreement were unable to reach an agreement with respect to how to proceed regarding the communications that the Utility reported to the CPUC on September 21, 2017. Also on November 1, 2017, the non-Utility parties to the settlement requested that the CPUC approve the settlement, as modified by the PD, and open a second phase of the OII to investigate and consider appropriate sanctions for the new communications reported by the Utility on September 21, 2017, and others that may be discovered.

On November 30, 2017, the CPUC issued a decision extending the statutory deadline to June 29, 2018 to resolve the proceeding. The CPUC stated that an extension of the statutory deadline was necessary to allow the assigned administrative law judge time to prepare the revised decision and to open and resolve a second phase of this proceeding.

The Utility is unable to predict the outcome of this proceeding.

At December 31, 2017, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $24 million accrual for the amounts payable to the California General Fund and the Cities of San Bruno and San Carlos. In accordance with accounting rules, adjustments related to revenue requirements would be recorded in the periods in which they are incurred.

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.

Potential Safety Citations

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. There are a number of audit findings, as well as other potential violations identified through various investigations and the Utility's self-reported non-compliance with laws and regulations, on which the SED has yet to act. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation.

The SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED also has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The SED also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged. Historically, the SED has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. In the past, the SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The CPUC can also open an OII and levy additional fines even after the SED has issued a citation.

The Utility is unable to reasonably estimate the amount or range of future charges as a result of SED investigations or any proceedings that could be commenced in connection with potential violations of electric and natural gas laws and regulations.

Other Matters

Other Contingencies

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 above under "Enforcement and Litigation Matters") totaled $86 million at December 31, 2017 and $45 million at December 31, 2016. These amounts are included in Other current liabilities in the Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowances are reflected in operating and maintenance expenses in the Consolidated Statements of Income. Disallowances as a result of the CPUC's June 2016 final phase one decision and December 2016 final phase two decision in the Utility's 2015 GT&S rate case, the Utility's Pipeline Safety Enhancement Plan, and CPUC's final decision on the closure of Diablo Canyon are discussed below.

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. 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 $85 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending.

Capital Expenditures Relating to Pipeline Safety Enhancement Plan

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of December 31, 2017, the Utility has spent $1.38 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected to exceed the authorized amount. The Utility expects the remaining PSEP work to continue throughout 2018. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

Capital Expenditures Relating to the Diablo Canyon Power Plant

On January 11, 2018, the CPUC issued a final decision adopting the settlement agreement jointly submitted to the CPUC in May 2017 related to the recovery of license renewal costs and cancelled project costs within the Utility's application to retire Diablo Canyon. The final decision allows for recovery from customers of $18.6 million of the total license renewal project cost of $53 million evenly over an 8-year period beginning January 1, 2018. Related to cancelled project costs, the decision allows for recovery from customers of 100% of the direct costs incurred prior to June 30, 2016 and 25% recovery of direct costs incurred after June 30, 2016. During the year ended December 31, 2017, the Utility incurred charges of $47 million related to the Diablo Canyon capital expenditures settlement agreement, of which $24 million is for cancelled projects and $23 million is for disallowed license renewal costs. The Utility does not expect to incur additional charges as a result of the CPUC's final decision, other than additional project cancellation costs that the Utility does not expect to be material.

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 composed of the following:

	Balance at	
(in millions)	**December 31 2017**	**December 31, 2016**
Topock natural gas compressor station	$ 334	$ 299
Hinkley natural gas compressor station	147	135
Former manufactured gas plant sites owned by the Utility or third parties(1)	320	285
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites(2)	115	131
Fossil fuel-fired generation facilities and sites(3)	123	108
Total environmental remediation liability	**$ 1,039**	**$ 958**

(1) Primarily driven by the following sites: Vallejo, SF East Harbor, Napa, and SF North Beach
(2) Primarily driven by the Shell Pond site
(3) Primarily driven by the SF Potrero Power Plant site

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 state and federal regulatory agencies under the federal Resource Conservation and Recovery Act and/or 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, on an ongoing basis, measures that may be necessary to comply with these laws and regulations 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, 2017 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to implement final remediation plans and the Utility's required 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 impact on results of operations, financial condition and cash flows during the period in which they are recorded. At December 31, 2017, the Utility expected to recover $725 million of its environmental remediation liability 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 DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. On December 21, 2017 the DTSC issued its final environmental impact report. The environmental impact report includes requirements related to conditions of work that have been anticipated or previously required and are accounted for in the current environmental remediation liability. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $289 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 through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing interim 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 final clean-up and abatement order 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 requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes 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 $145 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 ("MGPs")

Former manufactured gas plants used coal and oil to produce gas for use by the Utility's customers in the past. The by-products and residues of this process were often disposed at the manufactured gas plants 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 $343 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 are long-term projects that are undergoing a remediation process. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $145 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 has sold its fossil-fueled power plants, the Utility has 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 $106 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.

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 compensation from the federal government and will provide up to its full policy limit of $3.2 billion for each insured loss. In contrast, NEIL would treat 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 the $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.

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, 2017, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $57 million. 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 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, 2017.

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 $13.5 billion. The Utility purchased the maximum available public liability insurance of $450 million for Diablo Canyon. The balance of the $13.5 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $255 million per nuclear incident under this program, with payments in each year limited to a maximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

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, covering liabilities in excess of the liability insurance.

Resolution of Remaining Chapter 11 Disputed Claims

Various electricity suppliers filed claims in the Utility's 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 has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has 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 are, in some instances, 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, 2017 and December 31, 2016, respectively, the Consolidated Balance Sheets reflected $243 million and $236 million in net claims within Disputed claims and customer refunds. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

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, 2017:

	Power Purchase Agreements					
(in millions)	Renewable Energy	Conventional Energy	Other	Natural Gas	Nuclear Fuel	Total
2018	$ 2,150	$ 718	$ 280	$ 388	$ 96	$ 3,632
2019	2,193	706	221	167	102	3,389
2020	2,188	686	175	148	143	3,340
2021	2,168	588	153	93	70	3,072
2022	1,975	512	143	93	60	2,783
Thereafter	26,005	657	526	357	151	27,696
Total purchase commitments	**$ 36,679**	**$ 3,867**	**$ 1,498**	**$ 1,246**	**$ 622**	**$ 43,912**

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, 2017, renewable energy contracts expire at various dates between 2018 and 2043.

Conventional Energy Power Purchase Agreements. The Utility has entered into 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, 2017, these power purchase agreements expire at various dates between 2018 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. Several of these agreements are treated as capital leases. At December 31, 2017 and 2016, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $18 million and $35 million including accumulated amortization of $143 million and $148 million, respectively. The present value of the future minimum lease payments due under these agreements included $11 million and $17 million in Current Liabilities and $7 million and $18 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2017, QF contracts in operation expire at various dates between 2018 and 2028. 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 $3.3 billion in 2017, $3.5 billion in 2016, and $3.5 billion in 2015.

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 2018 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California in order 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 $0.9 billion in 2017, $0.7 billion in 2016, and $0.9 billion in 2015.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2018 and 2025 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 $83 million in 2017, $100 million in 2016, and $128 million in 2015.

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 2018 and 2052. At December 31, 2017, the future minimum payments related to these commitments were as follows:

(in millions)	**Operating Leases**
2018	$ 44
2019	41
2020	40
2021	36
2022	27
Thereafter	138
Total minimum lease payments	**$ 326**

Payments for other commitments related to operating leases amounted to $45 million in 2017, $43 million in 2016, and $41 million in 2015. 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.

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	03/09/2018	End of 2017/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				3,223,118
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				812,168
3	Preceding Quarter/Year to Date Changes in Fair Value				(1,602,029)
4	Total (lines 2 and 3)				(789,861)
5	Balance of Account 219 at End of Preceding Quarter/Year				2,433,257
6	Balance of Account 219 at Beginning of Current Year				2,433,257
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				520,640
8	Current Quarter/Year to Date Changes in Fair Value				3,336,770
9	Total (lines 7 and 8)				3,857,410
10	Balance of Account 219 at End of Current Quarter/Year				6,290,667

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1to 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			3,223,118		
2			812,168		
3			(1,602,029)		
4			(789,861)	1,401,692,694	1,400,902,833
5			2,433,257		
6			2,433,257		
7			520,640		
8			3,336,770		
9			3,857,410	1,691,270,758	1,695,128,168
10			6,290,667		

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	03/09/2018	End of 2017/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	69,350,606,905	50,549,922,802
4	Property Under Capital Leases	179,049,740	160,819,019
5	Plant Purchased or Sold	-513,182	-219,416
6	Completed Construction not Classified	11,471,649,228	6,518,632,798
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	81,000,792,691	57,229,155,203
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,470,588,868	1,701,046,695
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	83,471,381,559	58,930,201,898
14	Accum Prov for Depr, Amort, & Depl	35,680,789,356	25,690,477,299
15	Net Utility Plant (13 less 14)	47,790,592,203	33,239,724,599
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	34,639,586,669	25,630,993,906
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	8,327,006	
21	Amort of Other Utility Plant	1,032,875,681	59,483,393
22	Total In Service (18 thru 21)	35,680,789,356	25,690,477,299
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)	35,680,789,356	25,690,477,299

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
12,797,373,665				6,003,310,438	3
				18,230,721	4
-293,766					5
4,437,199,805				515,816,625	6
					7
17,234,279,704				6,537,357,784	8
					9
					10
370,817,672				398,724,501	11
					12
17,605,097,376				6,936,082,285	13
7,372,281,441				2,618,030,616	14
10,232,815,935				4,318,051,669	15
					16
					17
7,359,060,518				1,649,532,245	18
					19
8,327,006					20
4,893,917				968,498,371	21
7,372,281,441				2,618,030,616	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
7,372,281,441				2,618,030,616	33

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	280,145,003	95,873,965
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	280,145,003	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	402,677,540	114,255,938
10	SUBTOTAL (Total 8 & 9)	402,677,540	
11	Spent Nuclear Fuel (120.4)	2,164,292,005	100,849,302
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,381,791,989	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	465,322,559	
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
	114,255,938	261,763,030	3
			4
			5
		261,763,030	6
			7
			8
	100,849,302	416,084,176	9
		416,084,176	10
		2,265,141,307	11
			12
-123,258,253		2,505,050,242	13
		437,938,271	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	03/09/2018	2017/Q4

FOOTNOTE DATA

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

Cost of fuel inserted into reactor during 2017; 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 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	03/09/2018	End of 2017/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	113,935,938	
4	(303) Miscellaneous Intangible Plant	2,670,846	1,462,032
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	116,606,784	1,462,032
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,644,205	
9	(311) Structures and Improvements	112,610,828	950,445
10	(312) Boiler Plant Equipment	274,353,445	2,154,972
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	256,400,802	979,530
13	(315) Accessory Electric Equipment	51,279,293	1,316,693
14	(316) Misc. Power Plant Equipment	28,295,578	53,326
15	(317) Asset Retirement Costs for Steam Production	92,189,557	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	823,773,708	5,454,966
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	22,726,561	
19	(321) Structures and Improvements	1,047,677,888	54,315,566
20	(322) Reactor Plant Equipment	3,491,803,408	61,309,459
21	(323) Turbogenerator Units	1,167,598,328	5,008,174
22	(324) Accessory Electric Equipment	816,002,501	39,119,991
23	(325) Misc. Power Plant Equipment	1,121,958,795	38,313,032
24	(326) Asset Retirement Costs for Nuclear Production	2,246,610,062	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	9,914,377,543	198,066,222
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	41,929,067	1,484,752
28	(331) Structures and Improvements	475,380,045	26,190,770
29	(332) Reservoirs, Dams, and Waterways	2,016,127,818	67,696,098
30	(333) Water Wheels, Turbines, and Generators	871,276,485	89,337,558
31	(334) Accessory Electric Equipment	266,288,843	6,923,000
32	(335) Misc. Power PLant Equipment	92,562,564	2,917,219
33	(336) Roads, Railroads, and Bridges	79,511,728	6,335,574
34	(337) Asset Retirement Costs for Hydraulic Production	7,200,427	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	3,850,276,977	200,884,971
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,207,870	
38	(341) Structures and Improvements	210,375,654	228,365
39	(342) Fuel Holders, Products, and Accessories	11,271,196	
40	(343) Prime Movers	226,089,479	-1,161
41	(344) Generators	353,570,110	111,125
42	(345) Accessory Electric Equipment	211,826,751	1,030,981
43	(346) Misc. Power Plant Equipment	97,426,135	31,793
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,129,767,195	1,401,103
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	15,718,195,423	405,807,262

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	03/09/2018	End of 2017/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	257,255,292	21,685,102
49	(352) Structures and Improvements	447,854,392	13,509,490
50	(353) Station Equipment	5,874,296,572	316,048,884
51	(354) Towers and Fixtures	835,516,593	82,267,749
52	(355) Poles and Fixtures	1,034,279,200	144,506,830
53	(356) Overhead Conductors and Devices	1,455,023,441	86,965,844
54	(357) Underground Conduit	498,563,273	6,657,249
55	(358) Underground Conductors and Devices	262,454,432	10,910,375
56	(359) Roads and Trails	72,951,429	13,807,838
57	(359.1) Asset Retirement Costs for Transmission Plant	2,833,074	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	10,741,027,698	696,359,361
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	177,552,962	1,211,210
61	(361) Structures and Improvements	323,809,762	3,410,241
62	(362) Station Equipment	3,191,557,045	178,368,231
63	(363) Storage Battery Equipment	33,099,534	133,051
64	(364) Poles, Towers, and Fixtures	3,932,654,513	408,868,851
65	(365) Overhead Conductors and Devices	4,515,505,201	209,999,311
66	(366) Underground Conduit	2,760,932,941	100,447,813
67	(367) Underground Conductors and Devices	4,320,397,227	241,447,440
68	(368) Line Transformers	3,164,612,244	313,876,945
69	(369) Services	3,128,727,745	145,928,924
70	(370) Meters	1,119,011,576	49,927,492
71	(371) Installations on Customer Premises	27,313,912	
72	(372) Leased Property on Customer Premises	895,448	
73	(373) Street Lighting and Signal Systems	220,765,257	11,070,625
74	(374) Asset Retirement Costs for Distribution Plant	13,423,729	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	26,930,259,096	1,664,690,134
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	
88	(391) Office Furniture and Equipment	16,325,133	630,934
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	118,935,742	10,997,507
92	(395) Laboratory Equipment	14,445,289	534,289
93	(396) Power Operated Equipment	271,024	
94	(397) Communication Equipment	216,836,673	74,253,147
95	(398) Miscellaneous Equipment	55,354,088	15,753,494
96	SUBTOTAL (Enter Total of lines 86 thru 95)	433,847,444	102,169,371
97	(399) Other Tangible Property	468,499,422	
98	(399.1) Asset Retirement Costs for General Plant	7,076,635	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	909,423,501	102,169,371
100	TOTAL (Accounts 101 and 106)	54,415,512,502	2,870,488,160
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)	54,415,293,086	2,870,488,160

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
			113,935,938		3
6,646			4,126,232		4
6,646			118,062,170		5
					6
					7
			8,644,205		8
			113,561,273		9
			276,508,417		10
					11
			257,380,332		12
			52,595,986		13
			28,348,904		14
	3,912,478		96,102,035		15
	3,912,478		833,141,152		16
					17
			22,726,561		18
16,220,460			1,085,772,994		19
35,639,007			3,517,473,860		20
2,007,363			1,170,599,139		21
8,352,920			846,769,572		22
12,602,452	-4,850		1,147,664,525		23
	26,006,565		2,272,616,627		24
74,822,202	26,001,715		10,063,623,278		25
					26
515,280		-596,343	42,302,196		27
2,196,942			499,373,873		28
5,351,848		596,343	2,079,068,411		29
6,353,985			954,260,058		30
2,162,550			271,049,293		31
553,641			94,926,142		32
839,656			85,007,646		33
			7,200,427		34
17,973,902			4,033,188,046		35
					36
			19,207,870		37
			210,604,019		38
			11,271,196		39
			226,088,318		40
			353,681,235		41
			212,857,732		42
			97,457,928		43
					44
			1,131,168,298		45
92,796,104	29,914,193		16,061,120,774		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		-2,331,888	276,608,506		48
	-121,111		461,242,771		49
28,959,244	5,091,179	4,068,089	6,170,545,480		50
993,539		183,411	916,974,214		51
4,259,808			1,174,526,222		52
7,097,459		1,034,648	1,535,926,474		53
355,366			504,865,156		54
729,545			272,635,262		55
			86,759,267		56
	1,155,777		3,988,851		57
42,394,961	6,125,845	2,954,260	11,404,072,203		58
					59
17		-3,701,716	175,062,439		60
129,937			327,090,066		61
17,350,220		1,683,388	3,354,258,444		62
			33,232,585		63
15,701,096		-2,621,871	4,323,200,397		64
34,728,447		-332,632	4,690,443,433		65
18,305			2,861,362,449		66
7,695,086	138,739		4,554,288,320		67
27,090,458			3,451,398,731		68
2,328,103			3,272,328,566		69
11,224,610			1,157,714,458		70
			27,313,912		71
			895,448		72
47			231,835,835		73
	1,810,071		15,233,800		74
116,266,326	1,948,810	-4,972,831	28,475,658,883		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			424,632		86
			11,254,863		87
1,327,423			15,628,644		88
					89
					90
			129,933,249		91
423,427			14,556,151		92
			271,024		93
80,793			291,009,027		94
1,145,081	809,901		70,772,402		95
2,976,724	809,901		533,849,992		96
			468,499,422		97
	215,521		7,292,156		98
2,976,724	1,025,422		1,009,641,570		99
254,440,761	39,014,270	-2,018,571	57,068,555,600		100
					101
			219,416		102
					103
254,440,761	39,014,270	-2,018,571	57,068,336,184		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	03/09/2018	End of 2017/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					
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41					
42					
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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	03/09/2018	End of 2017/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	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				
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32				
33				
34				
35				
36				
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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	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74001423 MISSOURI FLAT-GOLD HILL 115 KV - LINE	41,314,053
2	7054908 MC-P Relic- Project Management	35,157,493
3	74001039 LARKIN: REPL 12KV SWGR	28,590,389
4	68011748 PLO-U2:Repl Main Generator Stator	28,561,552
5	30924121 MIDWAY FAULT DUTY MITIGATION PROJECT	24,393,203
6	7070913 DS conduct Rel studies	21,863,972
7	74003962 64-MOSS LANDING 115 KV BUS TO BAAH	20,119,586
8	74002445 GATES BAAH #2 500/230 KV	19,037,290
9	68001801 PLO-U1: Rpl Process Protection Sys (PPS)	17,395,294
10	74001857 EL CERRITO G: 115KV BUS UPGRADE PHASE 1	17,387,683
11	74015944 EMBARCADERO (SF-Z) DECOUPLE BKS 1, 3, 5	16,237,362
12	74001604 NC_WINDSOR-NEW BANK & SWITCHGEAR INSTALL	15,216,430
13	74008406 Q632B SAN JOAQUIN 1A CRESCENT Switching Station	14,925,059
14	7021725 UNFFR Relic Routine Project Management	14,838,950
15	68032509 PLO-COM: Procure Casks-Load Campaign UFO	14,348,169
16	68018981 PLO-CRVS Design Vulnerability	14,157,782
17	74000925 MIDWAY ANDREW_CPUC LIC/PER	13,941,115
18	74001904 Rebuild GREEN VALLEY SUB Breaker-and-a-Half	13,637,842
19	74000924 ESTRELLA_CPUC LIC/PER	13,608,891
20	74001521 NC_TBL MTN: REP 500KV CAP BK 4	13,340,635
21	74015952 EMBARCADERO GIS BK 1 & HZ-2 CUTOVER	13,130,441
22	74000916 Kern 230kV Bus Upgrade (Sub)	12,770,987
23	74000996 67-OLEUM PP - INSTALL 115 KV MPAC	11,443,709
24	74001801 230kV Wilson Series Reactor Addition	11,222,663
25	13004820 Drum Spaulding - Developing PAD and NOI	11,220,345
26	7026033 UNFFR Relic Aquatic Resource Stdy	10,664,429
27	74000939 WRJ NONCOMPETITIVE_CPUC LIC/PER	9,701,470
28	68039380 PLO: Integrated Video Mgmt Sys Upgrade	9,330,759
29	74000706 BRIGHTON-DAVIS 115KV NERC STEEL	9,204,018
30	74000737 HUMBOLDT-TRINITY 115KV (WOOD) PH.1 NERC	8,931,247
31	74001858 EL CERRITO G: REPL 12KV CBS W/SWGR	8,777,574
32	13003982 DS-C Relic- Cond studies for all RA	8,517,659
33	74003961 67-MOSS LANDING 115 KV AUTO - MPAC	8,453,037
34	74001780 NV_RIO OSO SUB 230KV BAAH/GIS	8,285,485
35	74000901 MARTIN BUS EXTENSION_CPUC LIC/PER	8,031,807
36	74002376 BORDEN 230 KV VOLTAGE SUPPORT (SUB)	7,977,513
37	31186691 UPGRADE SUSTAINMENT	7,954,994
38	74000857 SPRING NONCOMPETITIVE_CPUC LIC/PER	7,859,541
39	74001059 Pit 5 Repl Transformer-B1ABC & B2ABCSP	7,788,979
40	68001812 PLO-U2: Rpl Process Protection Sys (PPS)	7,708,706
41	7017646 Poe Relic - Prepare Exhibit E	7,210,530
42	74000933 LOCKEFORD-LODI_CPUC LIC/PER	7,150,827
43	TOTAL	1,701,046,695

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74001782 NV_RIO OSO SUB 115KV BAAH/GIS	7,146,830
2	7011106 Poe Relic - Project Management	7,095,773
3	74007760 LIVERMORE SUBSTATION TRAINING FACILITY	7,022,243
4	7076869 Buck Rel Studies	6,996,618
5	68014363 U1 SFP Bridge Crane Upgrades	6,893,461
6	74001097 COOLEY LANDING 115/60 KV TANSFORMER NO.2	6,855,869
7	74000736 CRESTA-RIO OSO 230KV NERC	6,644,466
8	74002346 NV_PEASE-MARYSVILLE 60KV L CONV MVILL SU	6,599,928
9	68031962 PLO- COM: Simulator Upgrade Phase V	6,301,917
10	74001391 60-SOUTH OF PALERMO REINFORCEMENT (PH-1)	6,173,863
11	74000600 FULTON-FITCH MTN. RECOND 60KV LN	6,126,491
12	74000662 NC_VALLEJO B: REPL. 4KV SWGR & BANKS	6,014,622
13	7026032 UNFFR Relic Water Use & Qlty Stdy	5,752,467
14	74001063 GATE-GREGG 230KV T-LINE CPUC LIC/PER	5,659,236
15	74000966 MIDWAY 230KV BUS DIFFERENTIAL PROJECT	5,604,071
16	74001708 SANGER NEW 115KV MPAC	5,547,189
17	7026037 UNFFR Relic Land Use/Mgt Study	5,508,326
18	7058680 Permit Holdover Project - Distribution	5,326,838
19	7055507 DS Relic- Strategic Planning	5,324,530
20	74001602 NC_WINDSOR SUB: RING BUS INSTALLATION	5,243,928
21	68016663 PLO-U2:NFPA 805 Fire Detection Sys Upgr	5,153,685
22	7055646 DS Relic- Project Management	5,147,137
23	74004000 NC_FAIRHAVEN: REPLACE 60KV	5,145,891
24	74011760 NETWORK SCADA Y-2	5,036,086
25	74011665 Pit 1 U2 Rewind	4,914,945
26	74001102 SF M SUB, REPLACE BK 2 12KV & 4KV SWGR	4,883,657
27	74001713 HUNTERS POINT: 115KV GIS BAAH	4,877,420
28	74001580 OAKLAND C REPL BANK #3	4,855,363
29	74001905 GREEN VALLEY SUB: 115KV MPAC	4,778,990
30	74012480 PARKWAY_MORAGA MITIGATE TWR 20/114	4,764,914
31	74011380 74011380_GREATER BAY ER STORAGE FAC SF	4,742,727
32	74015243 TSRP-NORTH BAY SIERRA PROJECT MANAGEMENT	4,537,127
33	74001942 KERN PP 230KV MPAC	4,531,065
34	74001853 EL CERRITO G: REPL BK 4 115-12KV, 60MVA,	4,507,937
35	30827391 R2Z OLD CNTY RD BELMONT PH1 R20A	4,478,281
36	74001223 REDWOOD CITY-REPL CB 404,406,408,409,410	4,347,972
37	74010941 Borden: Install MPAC	4,263,190
38	74007941 CALTRAIN INTERCONNECTIONS SUB SITE 3	4,217,097
39	74004836 MARTIN SUB:REPL 4KV SWGR &12-4KV BKS 3&5	4,209,648
40	7072819 Helms - Replace Liquid Rheostat	4,107,706
41	74001440 Tiger Creek U1 Rewind Generator	3,903,803
42	13023484 Pit 5 Turbine Pit Refurbishment	3,872,740
43	TOTAL	1,701,046,695

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	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	68015242 PLO-COM::Rplc Secondary Chem Lab	3,853,369
2	74002442 GATES 230KV Breaker-and-a-Half	3,841,058
3	74010524 GREATER BAY AREA TLINE MATERIALS OAK	3,810,386
4	74001000 SEMITROPIC-MIDWAY 115KV LINE RECOND (TL)	3,801,746
5	68020200 PLO: U2: REPL CFCU CLNG COILS (2R20) 2-5	3,784,650
6	74001487 JEFFERSON-MARTIN 230 KV RELOC @ CRYSTAL	3,768,582
7	30970621 PARADISE-TABLE MTN 115KV (STEEL) NERC	3,606,956
8	74013960 Pit 5 PH Surge Chamber & Valve House Sli	3,565,250
9	74003359 MARTIN SUB: REPL 230KV SHNT RCTR1	3,561,791
10	74001781 NV_RIO OSO SUB BANKS #1 & #2	3,523,881
11	74010530 GREATER BAY STORAGE FACILITY OAK	3,468,797
12	74000343 CALTRAIN INTERCONNECTIONS SUB SITE 1	3,355,256
13	74010662 Helms - Main Crane Modification	3,341,670
14	74001710 94-SANGER SUB: 115KV BUS REPLACEMENT	3,331,115
15	74006422 NEWARK SUB: SVC CONTROLLER UPDATE	3,313,991
16	74004621 DRUM-SUMMIT # 1 115KV NERC	3,306,208
17	30797619 OAKLEY GENERATING STN: LAS POSITAS-NEWAR	3,305,177
18	31232087 CARIBOU-WESTWOOD ROW RELIABILIYT	3,282,826
19	7049829 DC Relic Begin Prep of NOI and PAD	3,253,857
20	74001094 (DA-B&M) CORTINA NO. 3 60KV RECONDUCTOR	3,208,349
21	74001684 MIDWAY SUB-REPL 6SETS 500KV SWS PH2 SW 7	3,196,331
22	74001825 Tiger Creek Canal 2016/2017 Liner	3,174,194
23	7086449 IT for base camps	3,166,111
24	68019301 U1:Upgrade Polisher Computer Workstation	3,164,684
25	74000937 LOS BANOS - 70KV TLINE RECONFIGURATION	3,117,818
26	74000988 48-CASTRO VALLEY: REPL 12KV SWITCHGEAR	3,112,306
27	74001175 (DA-B&V) MOSHER-LOCKFORD 60KV RECOND.	3,105,586
28	74001718 NV_MI-WUK RING BUS CONVERSION	3,084,458
29	68029481 PLO-U2:Instl 230kV Open Ckt Fault Prot	3,067,515
30	74011400 GREATER BAY AREA TLINE MATERIALS SF	3,044,843
31	74010705 Pit 7 Road Refurb 2017 Storm Damage	3,032,671
32	7026034 UNFFR Relic Terres Resources Stdy	3,003,306
33	74001436 (DA-B&M) ELECTRA-VALLEY SPRGS CAP/RECOND	2,998,042
34	74001785 NV_RIO OSO SUB 230KV MPAC	2,994,543
35	74004614 SOBRANTE-"R" #2+ NERC PROJECT (STEEL)	2,992,556
36	74004964 SOBRANTE: ADD & REPL 14-115KV BKERS P2	2,972,943
37	74008287 Pit 3 Tailrace Slot & Conc. Replacement	2,964,300
38	74001688 NC_(DA-ABB) MAPLE CREEK SUB:REACTIVE SUP	2,959,306
39	74002462 NC_PEASE RECONFIG 115KV BUS TO BAAH CONF	2,947,580
40	7053945 DC Relic - Prepare Study Plans	2,939,134
41	74001362 ATWATER-LIVINGSTON-MERCED 115KV (PHASE 2	2,924,337
42	74001432 COTTNWD-RED BLUFF - RECONDUCTOR	2,916,866
43	TOTAL	1,701,046,695

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	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	68017320 PLO-Repl Oily Water Separator System	2,861,434
2	13006140 MC-P Relic- Conduct Relicensing Studies	2,854,148
3	74000825 LEMOORE NAS 70 KV SCADA SW#55,65	2,827,869
4	74003507 WINDSOR SUBSTATION:NEW FEEDER INSTALL	2,802,227
5	74004821 NV_VACA DIXON: REPL 500KV SERIES CAP BK2	2,800,189
6	13011860 Pit 6 Replace Trash Rake	2,793,243
7	74001046 PITTSBURG: INSTALL 2-60KV SCADA SW	2,784,643
8	74010041 Pit 6 Road Storm Damage Jan. 2017	2,784,132
9	68012041 PLO-U1:Replace U1 FLUR/SLUR Relays	2,778,170
10	31168761 ETTM SOUTH BAY MHP	2,768,086
11	74002229 SAN LUIS OBISPO REPL 70 KV BUS	2,763,326
12	7054909 MC-P Relic- Prepare NOI and PAD	2,699,267
13	7017635 Poe Relic Field Study/Aquatic Res	2,699,012
14	7043247 RCC Lic Imp Cold Water Feasibility Study	2,687,809
15	74011283 INSTALL BM-2106 FEEDER OUTLET	2,685,019
16	74009262 KASSON SUB: REPLACE BANK 1	2,680,318
17	74006762 METCALF-SALINAS NO. 1 (IDLE) (P3)	2,628,337
18	74008540 EM_FAIRMONT SUB - REPLACE FAILED TXFR402	2,625,251
19	74001677 NV_STOCKTON A SUB- REPLACE CB 402,404	2,592,368
20	74001786 NV_RIO OSO SUB 115KV MPAC	2,549,505
21	74004625 CRAGVIEW-CASCADE 115KV NERC	2,547,301
22	74001953 SAN FRAN F (MARINA): REPL 4KV SWGR	2,514,634
23	74001285 MELONES-RACETRACK NERC PROJECT	2,506,206
24	74001179 NV_94-INDIAN FLAT SUB:REPL SW 17 W/1-70K	2,488,121
25	13002402 DS-C Relic- Conduct Pre-App Proj Man	2,446,314
26	74000709 (DA-TRC) HUMBOLDT BAY RECONDUCTOR PROJ.	2,428,528
27	30842587 OAKLEY GENERATING STN:COCOPP-DELTA PUMPS	2,423,395
28	74005663 KERN PP: CONVERT 115KV BUS TO BAAH	2,418,261
29	7021727 UNFFR Relic Prepare 5 Year Library	2,417,718
30	74002444 GATES BANK NO. 2 500/230 KV TRANSFORMER	2,403,371
31	30854865 NEWARK-AMES 1300FT BOARDWALK	2,380,611
32	74006884 MORRO BAY SUB: UPGRADE 230KV BUS	2,364,902
33	68027382 PLO-COM:TS Setpoint Calcs Rev & Reloc	2,358,137
34	31168794 ETTM RANCHO VISTA MHP	2,343,198
35	74011788 TARGETED CABLE REPLACE.-LA WEST PH3	2,342,036
36	31221203 2017 FAA TOWER LIGHTING PROGRAM	2,338,321
37	31289409 ESSEX ORRICK JCT ROW PROGRAM 2017	2,332,500
38	74000936 WRJ COMPETITIVE_CPUC LIC/PER	2,323,771
39	13008740 Battle Crk - Phase 2 License Amendment	2,317,723
40	74000841 HERNDON-KEARNEY 230 KV LINE RECONDUCTOR	2,307,280
41	74000981 HERNDON SUB - NORTHERN FRESNO 115KV AREA	2,298,736
42	74001064 GATES-GREGG PRE-BID COSTS	2,290,371
43	TOTAL	1,701,046,695

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74002892 NV_VACA DIXON: REPL 500KV SERIES CAP BK1	2,244,019
2	74001526 SOBRANTE SUB 230 KV CB 202, 252	2,243,142
3	74004615 EAGLE ROCK-FULTON-SILVERADO NERC PROJECT	2,238,917
4	74006763 METCALF-SALINAS NO. 2	2,231,666
5	74000938 LOS BANOS - 70KV BUS CONFIGURATION	2,200,392
6	7026036 UNFFR Relic Rec Resources Study	2,190,055
7	68050742 PLO-U2: Repl DRPI Detector/Encoder Cards	2,166,364
8	74008620 Fordyce Dam Leakage Reduction	2,130,370
9	74000863 Helms - Plug & Bypass Tunnel Lining	2,128,038
10	68050600 PLO-U2: Repl HP Turbine Rotor Blades	2,120,175
11	74000856 SPRING COMPETITIVE_CPUC LIC/PER	2,117,572
12	74013123 TABLE MTN-TESLA TWR 109/429	2,086,121
13	13009580 DeSabla Replace Governor	2,072,742
14	13011921 NFSL Additional Design Imp	2,067,490
15	7076872 Buck Rel Lic App	2,022,965
16	74000731 EAST SHORE-OAKLAND J 115KV RECONDUCT(TL)	2,014,504
17	68018677 Support 02*998 PPS (EAGLE 21) PARTS U2	1,986,674
18	31168768 ETTM ALIMUR MOBILE HOME PARK	1,979,172
19	74004612 VACA-VACAVILLE-JMSN-N TWR 115KV NERC PH1	1,973,357
20	74001334 TEMBLOR-SAN LUIS OBISPO 115KV NERC	1,966,019
21	68014444 PLO-U1:Replace Main Gen Output Breaker	1,959,473
22	74001620 Pit 3 Unit 3 Replace Rewind	1,957,662
23	30940862 EL DORADO-MISSOURI FLAT #1 NERC PRJ	1,955,215
24	74010660 Balch 2 - U2 Replace Cooling Water	1,934,095
25	74000707 60 KINGSBURG-LEMOORE 70KV RECOND. PH1	1,930,619
26	74006681 MIDWAY BANK 12 RELAY PROJECT	1,929,465
27	74000602 CARIBOU#2 GRAYS FLAT TO SPANISH CREEK	1,921,655
28	74006580 NV_TESLA 230KV BUS DIFFERENTIAL REPLACE	1,921,645
29	74001909 LEMOORE 70KV DISCONNECT SWITCHES REPLAC	1,904,808
30	68029724 U1: Control Room Condenser Replacement	1,898,134
31	13019060 Shasta Area Scoping-Old Sierra Equipment	1,896,686
32	74003104 Haas U1 Upgrade Cooling Water Sys	1,893,583
33	31238846 MAPLE CREEK-HOOPA 60 KV ROW RELIABILITY	1,892,662
34	74014700 Pit 6 U1 Replace Transformer	1,891,531
35	74001502 FAMOSO SUB: INSTALL D-SCADA ON BK1-CB110	1,891,487
36	74000959 MCCALL SUB - NORTHERN FRESNO 115KV AREA	1,887,339
37	68000145 Lead Order-U1:Repl Boric Acid Xfer Pumps	1,877,451
38	68032804 PLO- COM: Tornado Missile LAR	1,873,796
39	74001188 NC_LAS GALLINAS:REPL 115KV MOAS	1,863,570
40	74003358 NC_PIT PH 1 SUB: ADD BK 5	1,851,242
41	74003144 NV_BELLOTA 230 KV SHUNT REACTOR	1,850,491
42	68005100 Lead Order-License Renewal Application	1,844,840
43	TOTAL	1,701,046,695

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	7026029 UNFFR Relic Prep 1st Stage Consult Pkg	1,821,424
2	74002214 NC_HOPLAND: REPL BANK 2 (115/60 KV)	1,820,735
3	74006883 ENHANCED VOLTAGE STABILITY ASSESSMENT	1,804,523
4	31144012 DF CABLE PHASE 3 - EB 2014	1,803,206
5	74004900 GATES INSTALL CAP BANK CONTROLLERS 1&2	1,772,781
6	74011030 KERN 230KV BAAH 115KV LINE RELOCATION	1,771,455
7	74006641 NC_ROUND MTN: REPL SCB 4 CONTROLLER	1,761,811
8	74008356 GATES: INSTALL CAP BANK CONTROLLERS 3&4	1,758,492
9	68038260 PLO-COM: North Access Rd Upgrade	1,755,449
10	74001720 SAN MIGUEL: INSTALL T-SCADA CB12& 22	1,745,459
11	74001683 MIDWAY SUB: WHIRLWIND & VINCENT 1&2 500K	1,743,194
12	68037580 PLO-COM:HEPA Fltr TSC Mkup Air Sply Dct	1,721,892
13	74002321 Inskip Eagle Canyon Access Safety Improv	1,713,682
14	31214160 EM_RICHMOND Q SUB - REPL. UNIT SUBS	1,712,386
15	74008281 Bucks Cr Replace Turb Brg / Shaft	1,708,312
16	74000345 CHSR INTERCONNECTIONS SUB SITES 4-7	1,699,152
17	30866456 REPLACE OUTLET CABLES @ SAN LEANDRO U	1,696,591
18	31168784 ETTM CASA GRANDE MHP	1,688,558
19	31158648 ORIOLE EMERGENCY REPLACEMENT CB 401	1,680,284
20	31289408 CARIBOU 2 ROW PROGRAM 2017	1,660,037
21	74001200 EXCHEQUER SUB TO BEAR VALLEY SUB	1,650,647
22	74000712 R2 GATES-TULARE LAKE RELIABILITY PROJ	1,649,553
23	74009026 MIDWAY SUB: REPL CAP BANK 2 CONTROLLER	1,644,621
24	68034341 PLO: COM: MSLB Impact on 4KV vital SWGRs	1,640,330
25	74001792 COLEMAN-RED BLUFF_CPUC LIC/PER	1,636,904
26	74001112 RIPON NEW 115 KV LINE 2ND TAP RELIABILIT	1,622,862
27	13011869 Pit 6 Replace Stoplog Lifting Device	1,615,023
28	68041440 PLO: COM:Upgrd RCP Vibe Monitoring Equip	1,605,442
29	74008366 MESA SUB VOLTAGE SUPPORT	1,601,000
30	74004888 OAKLAND D SUB: REPLACE 4KV SWITCHGEAR	1,578,484
31	74000341 CHSR INTERCONNECTIONS SUB SITES 8-13	1,570,019
32	31168808 ETTM EL RANCHO MOBILE HOME PARK	1,568,822
33	13011870 Pit 7 Replace Stoplog Lifting Device	1,537,224
34	74001453 Electra U3 New Needle, Stem & Bushings	1,535,257
35	13023881 Pit 5 TGB Lube Oil Skid Replacement	1,519,959
36	74001031 MIDWAY-KERN PP #2 230 KV LINE KERN AREA	1,507,328
37	7062249 MC-P- Proj Scoping and Study Plan Devp	1,506,818
38	7070917 DS Post App filing activities	1,503,689
39	74004825 64-HICKS SUB: 230 KV BUS REL IMPROV	1,500,035
40	74001732 VIERRA 115 KV REINFORCEMENT (T-LINE)	1,497,994
41	74004682 JACOBS CORNER 09 INSTALL SCADA 1101&1102	1,491,579
42	74001856 EL CERRITO G: 115KV BUS UPGRADE PHASE 2	1,483,851
43	TOTAL	1,701,046,695

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	31168732 ETTM GLENBROOK MOBILE ESTATES LP	1,482,466
2	68006140 Lead Order-U2:Repl FLURs/SLURs	1,477,038
3	74011780 PH1 INSTALLTIE FOR SIERRA@TAHOE7500'	1,475,789
4	74001739 MAPLE CREEK-WILLOW CK 60KV RELIABILITY	1,475,462
5	74004617 GEYSERS #9-LAKEVILLE NERC PROJECT	1,468,382
6	13002403 DS-C Relic- Conduct Studies	1,465,011
7	74001462 Drum 1 U1-4 Replace Exciters	1,463,896
8	74013124 VACA-TESLA 500KV LINE TWR	1,428,498
9	74009946 GREGG SUB: UPGRADE PHYSICAL SECURITY	1,419,911
10	7017638 Poe Relic Field Study/Recreation	1,418,824
11	74001923 INSTALL T-SCADA @ HAAS PH	1,414,641
12	74000828 DOS PALOS 70KV SCADA SWS	1,400,237
13	7049828 DC Relic Project Management	1,394,967
14	74004616 FULTON JCT-VACA NERC PROJECT	1,392,907
15	74000714 (DA-CE) COLGATE-CHALLENGE RELIABILITY	1,389,570
16	74000940 WHEELER RIDGE JUNCTION SUBSTATION	1,381,865
17	74001957 MONTA VISTA 230 KV BUS UPGRADE: PHASE1	1,380,967
18	74000900 Bucks Creek U2 Generator Rewind	1,379,675
19	74009955 PALERMO SUB: PHYSICAL SECURITY UPGRADE	1,376,747
20	74000990 64-CHRISTIE CB 32 & 72 REPLACEMENT PROJ	1,373,555
21	74001766 RAVENSWOOD-COOLEY LANDING 115 KV (TL)	1,371,551
22	74009800 WHEELER RIDGE RPLC BK1 EMER	1,370,508
23	74001588 NV_67-ORO LOMA: INSTALL 115 KV MPAC	1,367,114
24	74001044 REEDLEY-DINUBA 70 KV SOUTH RECONDUCTOR &	1,363,725
25	13006781 DeSabla-Centerville Proj Mgmt Post LA	1,353,139
26	7055645 DS Relic- Coord Study w/ NID	1,353,106
27	74004400 WOODWARD SUB: INSTALL SCADA TO BANK CB'S	1,349,285
28	74006740 Helms - U3 Rpl GSU Xfmr Heat Exchanger	1,340,428
29	68036981 PLO: COM: 500kv Road Upgrade	1,332,890
30	74001855 EL CERRITO G: 115KV BUS UPGRADE T-LINE	1,332,295
31	74012040 NICOLAUS-WILKENS SLOUGH 60KV LINE POLE	1,327,532
32	74003103 Haas U1 Replace Governor	1,324,811
33	74001735 POTRERO-MISSION #1 (A-X 1) SEISMIC RETRO	1,319,759
34	74002294 DIABLO CANYON PP: REPLACE CB 642	1,319,079
35	74007647 PEASE SUBSTATION EXPANSION - TLINE	1,318,892
36	74000713 ARCO-CHOLAME 70KV LINE RELIABILITY STUDY	1,317,133
37	74000668 DEEPWATER #1 TAP - NERC PROJECT	1,316,398
38	74004832 WEEDPATCH 70 KV CB 42 52 62	1,312,520
39	74005123 MORGAN HILL: EM UPGRD: YARD IMPROVEMENT	1,299,355
40	74001641 R2Z = HIDDENBROOKE BACKTIE	1,296,805
41	74001704 FIREBAUGH SUB - 70KV SCADA SWITCHES	1,293,529
42	74002003 Tiger Creek U1 Replace Exciter	1,292,024
43	TOTAL	1,701,046,695

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	74006720 Helms - U1 Rpl GSU Xfmr Heat Exchanger	1,272,975
2	74000665 BRIGHTON-GRAND ISLAND #1 & #2 115KV NERC	1,260,440
3	74001427 WEBER-SANTA FE JUNCTION 60 KV RECON	1,257,982
4	74008455 Cresta PH Arc Flash Remediation U1&U2	1,253,714
5	74002483 SPENCE SUB INSTALL BK1 FOR CAPACITY	1,240,598
6	74000846 METCALF - EVERGREEN RECONDUCTORING (TL)	1,233,501
7	74001734 MARTIN-LARKIN #1 115 KV CABLE (H-Y 1)	1,233,364
8	30760432 LARKIN SUB_CPMC NEW CKT_CAPACITY	1,227,255
9	74002465 SOBRANTE CB 202 RELAY UPGRADE	1,227,136
10	74001397 (DA-TRC)ESSEX JCT ORICK 60KV RELIABILITY	1,225,616
11	68011828 U2: Control Room Condenser Replacement	1,225,564
12	74001579 OAKLAND L-CUTOVER 4KV TO 12KV	1,223,208
13	74001742 MIDWAY-TEMBLOR 115 KV LINE SCADA PROJECT	1,220,473
14	74001733 POTRERO-LARKIN #2 (A-Y2) SEISMIC RETROFI	1,219,321
15	68042983 PLO: U1/U2 Repl Intake Debris Grinders	1,211,726
16	7060966 COM:Instl Bar Rack Rake System	1,209,557
17	74013101 DIXON LANDING RPLC BK3 EMER	1,204,888
18	74003503 Poe Dam Gate 3 Repl Arms & Trunnions	1,190,384
19	74001686 NC_MAPLE CREEK PROJ-BUS RECONFIGURATION	1,190,343
20	74002426 FELLOWS: INSTALL D-SCADA CB 2103 & 2104	1,189,431
21	74008849 CYMRIC SUB, 67-MRTU	1,183,109
22	74001441 Tiger Creek U1 Gen Relays Upgrade	1,179,284
23	31168695 ETTM COTTONWOOD MOBILE ESTATES	1,160,541
24	74000972 NC_PANORAMA: INSTALL: D-SCADA	1,157,326
25	74008601 SV_MIDWAY SUB: PHYSICAL_SECURITY UPGRADE	1,154,749
26	74005355 NV_RIO OSO SUB SVC	1,150,334
27	74001168 SANTA NELLA SUB: SW 17 & 19	1,147,830
28	74000622 BELLOTA - WARNERVILLE RECONDUCTOR	1,143,700
29	74008385 Coleman Decommission Asbury Pipe	1,136,821
30	74005962 EM GREGG REP CAP & CB	1,127,272
31	74008384 Battle Cr Salmon/Steelhead Phase 2	1,118,344
32	74008301 Lower Bucks Dam Resurface Face	1,116,439
33	13023485 Emergency Storm Damage Revetments -Roads	1,116,368
34	74005120 EVERGREEN SUB: 60KV PROTECTION UPGRADE	1,109,399
35	74011644 Halsey Sump Improvements	1,100,104
36	7073485 Salmon HEA Other Costs PG&E	1,086,296
37	31168799 ETTM RIVER PARADISE MOBILE ESTATES	1,085,216
38	74002486 KERN PP: INSTALL 115KV MPAC BLDGS	1,076,985
39	74009901 Rock Cr PH U1 & U2 Repl WG Seals	1,067,792
40	74004826 67-HICKS: INSTALL 230KV MPAC (CONSTR 201	1,066,821
41	74001555 EP 2019 STINE RD BAKERSFIELD R20A	1,063,983
42	74001220 FELLOWS SUB T-SCADA ON CB142,152 & M& MO	1,062,904
43	TOTAL	1,701,046,695

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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	68008644 Lead Order-U2 FHB Supply Fan Replace	1,041,800
2	31168691 ETTM PLEASANT VALLEY MH COMMUNITY	1,035,789
3	7076871 Buck Rel Draft Lic App	1,033,932
4	74001311 FAMOSO SUB: INSTALL T-SCADA	1,032,782
5	31298384 ODN SECURITY PROJECT	1,008,624
6	68000146 Lead Order-U2:Repl Boric Acid Xfer Pumps	1,001,003
7	See footnote for detail.	363,771,669
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42		
43	TOTAL	1,701,046,695

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 216.8 Line No.: 7 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	03/09/2018	End of 2017/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	24,238,665,711	24,238,665,711		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,980,795,695	1,980,795,695		
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	-155,934,823	-155,934,823		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,824,860,872	1,824,860,872		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	254,434,115	254,434,115		
13	Cost of Removal	222,371,313	222,371,313		
14	Salvage (Credit)	7,503,802	7,503,802		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	469,301,626	469,301,626		
16	Other Debit or Cr. Items (Describe, details in footnote):	36,768,949	36,768,949		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	25,630,993,906	25,630,993,906		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	411,252,616	411,252,616		
21	Nuclear Production	6,454,701,341	6,454,701,341		
22	Hydraulic Production-Conventional	1,362,636,080	1,362,636,080		
23	Hydraulic Production-Pumped Storage	766,637,778	766,637,778		
24	Other Production	280,677,797	280,677,797		
25	Transmission	2,987,546,220	2,987,546,220		
26	Distribution	12,805,944,295	12,805,944,295		
27	Regional Transmission and Market Operation				
28	General	561,597,779	561,597,779		
29	TOTAL (Enter Total of lines 20 thru 28)	25,630,993,906	25,630,993,906		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

FOOTNOTE DATA

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	254,434,115
Book Cost of Amortizable plant retired	6,646
Book cost of plant retired, pages 204-209, column (d)	254,440,761
Diff	0

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

Other Debit or Cr. Items (Describe):

FAS 143 Assets Depreciation (Nuclear & Fossil)	59,306,266
Decommissioning reclass to Regulatory Liability (Nuclear & Fossil)	(25,145,656)
FIN 47 Asset Depreciation (EDP, EHP, ETP, EGP)	1,875,395
Capital Lease Obligations	(4,432,656)
Mirant Adjustment	2,260,506
Gain/Loss	2,974,736
Reserve Adjustment	(69,642)
	36,768,949

Schedule Page: 219 Line No.: 28 Column: c

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

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			3,643,552
4	Undistributed Earnings			80,066
5				
6	SUBTOTAL			3,724,618
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			4,392,056
18	Undistributed Earnings			-4,421,943
19				
20	SUBTOTAL			-19,887
21				
22	Standard Pacific Gas Line Incorporated			
23	Common Stock	1930-32		1,200
24	Additional Paid in Capital	1954		39,953,917
25	Undistributed Earnings			-26,293,373
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			37,979,920
35				
36	Midway Power LLC			
37	Additional Paid in Capital	2008		26,027,928
38	Undistributed Earnings			-18,344,434
39				
40	SUBTOTAL			7,683,494
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	49,368,145

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	03/09/2018	End of 2017/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
		3,741,892		3
-57,270		22,796		4
				5
-57,270		3,765,688		6
				7
				8
		100,000		9
		3,037,432		10
		-3,137,432		11
				12
				13
				14
				15
		10,000		16
		4,698,621		17
184,942		-4,700,407		18
				19
184,942		8,214		20
				21
				22
		1,200		23
		43,473,426		24
71,357		-27,145,494		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
71,357		40,647,308		34
				35
				36
		26,085,184		37
-3,302,073		-21,646,507		38
				39
-3,302,073		4,438,677		40
				41
-3,103,044		48,859,887		42

FOOTNOTE DATA

Schedule Page: 224 Line No.: 41 Column: d

Total shown on line 42, column d ties to Page 110 line 21, column d.

Schedule Page: 224 Line No.: 41 Column: g

Total shown on line 42, column g ties to Page 110 line 21, column g.

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	03/09/2018	End of 2017/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	1,429,732	1,375,066	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)	92,981,614	98,115,315	ALL
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	121,888,519	131,373,581	ALL
8	Transmission Plant (Estimated)	32,145,308	31,138,026	ALL
9	Distribution Plant (Estimated)	99,478,067	104,997,211	ALL
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	346,493,508	365,624,133	
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)	347,923,240	366,999,199	

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	03/09/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	115,991.00		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	115,979.00		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)		13		
45	Gains		13		
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.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
13,860.00		13,860.00		360,360.00		517,931.00		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		531,779.00		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
					3		16	44
					3		16	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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 228 Line No.: 1 Column: b

This is a revision of the data previously submitted.

Schedule Page: 228 Line No.: 1 Column: d

This is a revision of the data previously submitted.

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 $419,420,000 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately $430,000 in alternative fuel vehicle credits.

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
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								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	03/09/2018	End of 2017/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	NONE					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Santa Cruz 115kV Reinforcement	3,800,000	116,111			3,683,889
22	10/4/2016 (03-2016 to 12/2075)					
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	3,800,000	116,111			3,683,889

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	03/09/2018	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3	(see details in footnotes)	2,839,042	186	(3,034,557)	186
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23	(see details in footnotes)	923,383	186	(1,972,783)	186
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 231 Line No.: 3 Column: a

Order	Order Description	BALANCE 12/31/2016	COSTS INCURRED PERIOD ENDED 12/31/2017	REIMBURSEMENTS RECEIVED PERIOD ENDED 12/31/2017	NET ACTIVITY PERIOD ENDED 12/31/2017	B 12
9718922	WG - USE - Cluster Analysis	92,460	-92,460		-92,460	
9719582	WG Gradient Resources Project SIS	22,884				
9719800	WAPA O'Neill Substation - System Impact	4,623				
9719900	WG - BURNS&MCDONNELL-Cluster work	68,019	-62,028		-62,028	
9720361	WG - CLUSTER 5 PROJECTS - PHASE 2	-1,051	1,051		1,051	
9722202	WG - C6 - Cluster 6 Phase 2	24,434				
9722840	WG - C7P1 - Cluster 7 Phase 1	-0	0		0	
9723860	WG - 2015 Reassessment	-0	0		0	
9724040	KMPUD Load Interconnection Study	-11,807				
9724060	WG-MMA-Q557-White River West - Storage	0	-0		-0	
9724281	WG - ISP - WGP Geysers	-129	129		129	
9724300	Ntwrk Eval for Calpine 115kV Geysers Gen	-12,209	1,840		1,840	
9724880	WG - C7P2 - Cluster 7 Phase 2	-0	0		0	
9724923	WG - C8P1 - Cluster 8 Phase 1	-2,264	2,264		2,264	
9724930	WG - C8 - SM - Midtown Park ES	-99	99		99	
9725000	WG - C8 - SM - Carneras Solar 1	128	-128		-128	
9725002	WG - C8 - SM - Quail Creek Solar 1	128				
9725003	WG - C8 - SM - Seneca Solar 1	128	-128		-128	
9725006	WG - C8 - SM - Alpaugh3BESS	128	-128		-128	
9725007	WG - C8 - SM - AmericanKings2	128	-128		-128	
9725008	WG - C8 - SM - AtwellWestBESS	128	-128		-128	
9725009	WG - C8 - SM - Britain	128	-128		-128	
9725010	WG - C8 - SM - CabrilloWind	274	-274		-274	
9725011	WG - C8 - SM - Corcoran2BESS	-50	50		50	
9725014	WG - C8 - SM - WhiteRiverBESS	128	-128		-128	
9725040	WG - C8 - SM - AnchoCreekSolar	128	-128		-128	
9725042	WG - C8 - SM # BearCanyonEnergyStorage	980	-980		-980	
9725045	WG - C8 - SM - MountVernonSolar	673	-673		-673	
9725046	WG - C8 - SM - OvejaSolarFarm	980	-980		-980	
9725047	WG - C8 - SM - WhiterockSolar	980	-980		-980	
9725049	WG - C8 - SM -AquamarineWestside	128	-128		-128	
9725053	WG - C8 - SM -HenriettaEnergyStorage	234	-234		-234	
9725054	WG - C8 - SM -MaricopaWestSolarPV3	140	-140		-140	
9725056	WG - C8 - SM -MoonPrism_2	250	-250		-250	
9725061	WG - C8 - SM #Scarlett	698	-698		-698	
9725063	WG - C8 - SM #Slate	68	-68		-68	
9725083	WG - C8 - SM -WestlandsAlmond	168	-168		-168	
9725084	WG - C8 - SM -WestlandsApricot	142	-142		-142	
9725085	WG - C8 - SM -WestlandsArtichoke	142	-142		-142	
9725086	WG - C8 - SM -AlamoSprings	980	-980		-980	
9725087	WG - C8 - SM -AlgosoES	980	-980		-980	
9725089	WG - C8 - SM #Brisbane	351	-351		-351	
9725090	WG - C8 - SM -CentralValleyProject	508	-508		-508	
9725095	WG - C8 - SM -FresnoSolar1	673	-673		-673	
9725101	WG - C8 - SM -OldKearneyES	366	-366		-366	
9725102	WG - C8 - SM -Periwinkle	980	-980		-980	
9725103	WG - C8 - SM -PointArenaES	980	-980		-980	
9725104	WG - C8 - SM -SantaMariaEnergyReliabilit	391	-391		-391	

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9725105	WG - C8 - SM -ShingleSpringsES	173	-173		-173
9725106	WG - C8 - SM -WestlandsSolarBlue	128	-128		-128
9725120	WG - C8 - SM -ChestnutWestside	27	-27		-27
9725121	WG - C8 - SM -CooleyLandingBESS	3	-3		-3
9725140	LID SIS Restudy	-10,808	10,808		10,808
9725260	WG - C8 - SM Primrose Engy Storage Cntr	-192	192		192
9725844	CDWR BDCP Phase 2 sudy	703			
9726101	WG MMA Q720 and Q1002 Lassen Lodge CODCH	1,063		-1,063	-1,063
9726740	WG - 2016 Reassessment Gen Interconn	-0	-0		-0
9726940	WAPA - Cottonwood Olinda line work	36,025	70,064		70,064
9727061	WG - C8P2 - Cluster 8 Phase 2	808,618	42,548	-851,165	-808,618
9727341	WG - C9P1 - Cluster 9 Phase 1	745,706	478,981	-1,224,686	-745,706
9727442	WG - C9 - SM - Los Arcos Solar	958	-958		-958
9727466	WG - C9 - SM - South Kern Front CHP	2,097	-2,097		-2,097
9727473	WG - C9 - SM - Westlands Cherry	271	-271		-271
9727700	WG - MMA -Q705- BlackwellFrt	2,589		-2,589	-2,589
9727720	SFPUC - Potrero Interconnection	-28,250	8,971	19,458	28,429
9727723	WG - MMA - Q965- SPWRJava	2,747	460	-3,207	-2,747
9727760	WG - Repowering Study - SPI-Sonora	12,468	7,641	-20,109	-12,468
9727881	WG - Repowering Study - SPI-Quincy	6,857	5,151	-12,008	-6,857
9727980	LBNL Capacity Increase	1,874	2,779		2,779
9728180	2016 Merced ID Load Interconnection Syst	7,277		-7,277	-7,277
9728201	WG - MMA - Q709 - GoldenHills - 2016 MMA	3,588	1,980	-5,568	-3,588
9728340	SVP Breaker Replacement	-12,331	3,467		3,467
9728360	Travis AFB Facility Study	-67,259	3,103		3,103
9728480	WG # MMA # Q705- Frontier-2016COD	463		-463	-463
9728526	Port of Stockton Load Increase	-23,843	1,954		1,954
9728582	WG # MMA # Q720&Q1002	929	140	-1,070	-929
9728645	WG # MMA # Q720&Q1002	-0	-0		-0
9728900	WG - MMA - Q272-2016COD	1,116	140	-1,256	-1,116
9728960	WG - MMA - Q679-Dec2016	795	4,843	-5,638	-795
9729004	WG # MMA # Q744-2016COD	636	553	-1,190	-636
9729040	2016 Merced ID Load Interconnection Faci	2,546	62,951	-85,000	-22,049
9729280	LBNL Interconnection Capacity Increase		23,583		23,583
9729340	WG - 2017 Reassessment		301,644		301,644
9729420	WG # MMA # Q632B-2017COD		838	-838	
9729546	WAPA SLTP		3,044		3,044
9729680	WG # MMA # Q1032-March2017		3,953	-3,953	
9729703	WG - C9P2 - Cluster 9 Phase 2		789,183		789,183
9729761	Port of Stockton FAS		9,636	-50,000	-40,364
9729808	WG - Cluster 10 IR Review for Protection		-0		-0
9729841	WG - C10P1 - Cluster 10 Phase 1		519,231		519,231
9729845	WG - C10 - SM - Project01		6,472	-6,577	-105
9729846	WG - C10 - SM - Project02		2,554	-2,682	-128
9729847	WG - C10 - SM - Project03		6,242	-6,370	-129
9729848	WG - C10 - SM - Project04		5,496	-5,738	-242
9729849	WG - C10 - SM - Project05		4,824	-4,980	-156
9729850	WG - C10 - SM - Project06		5,731	-5,989	-258
9729851	WG - C10 - SM - Project07		4,701	-4,898	-197
9729852	WG - C10 - SM - Project08		4,636	-4,884	-248
9729853	WG - C10 - SM - Project09		5,329	-5,521	-192
9729854	WG - C10 - SM - Project10		4,474	-4,712	-238
9729855	WG - C10 - SM - Project11		5,427		5,427
9729856	WG - C10 - SM - Project12		7,952	-8,087	-135
9729857	WG - C10 - SM - Project13		6,431	-6,544	-113

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9729858	WG - C10 - SM - Project14		1,440	-1,440		
9729859	WG - C10 - SM - Project15		4,688	-4,874	-186	
9729881	WG - C10 - SM - Project17		5,033	-5,260	-226	
9729882	WG - C10 - SM - Project18		4,653	-4,798	-146	
9729883	WG - C10 - SM - Project19		4,936	-5,060	-124	
9729884	WG - C10 - SM - Project20		5,749	-5,987	-238	
9729885	WG - C10 - SM - Project21		6,055	-12,018	-5,963	
9729886	WG - C10 - SM - Project22		4,974	-5,144	-170	
9729887	WG - C10 - SM - Project23		6,999	-7,144	-144	
9729888	WG - C10 - SM - Project24		5,953	-6,087	-133	
9729889	WG - C10 - SM - Project25		5,359	-5,511	-151	
9729890	WG - C10 - SM - Project26		5,396	-5,645	-249	
9729891	WG - C10 - SM - Project27		4,847	-5,044	-197	
9729892	WG - C10 - SM - Project28		5,458	-5,730	-272	
9729893	WG - C10 - SM - Project29		6,546	-6,811	-265	
9729894	WG - C10 - SM - Project30		6,394	-6,506	-112	
9729895	WG - C10 - SM - Project31		5,474	-5,694	-220	
9729896	WG - C10 - SM - Project32		5,030	-5,250	-220	
9729897	WG - C10 - SM - Project33		6,009	-6,111	-102	
9729898	WG - C10 - SM - Project34		6,226	-6,305	-79	
9729899	WG - C10 - SM - Project35		4,563	-4,710	-147	
9729900	WG - C10 - SM - Project36		5,123	-5,392	-269	
9729901	WG - C10 - SM - Project37		4,822	-4,999	-177	
9729902	WG - C10 - SM - Project38		6,239	-6,498	-259	
9729903	WG - C10 - SM - Project39		3,179	-3,249	-71	
9729904	WG - C10 - SM - Project40		4,472	-4,635	-163	
9729905	WG - C10 - SM - Project41		4,781	-4,977	-195	
9729906	WG - C10 - SM - Project42		6,047	-6,169	-122	
9729907	WG - C10 - SM - Project43		5,530	-5,839	-309	
9729908	WG - C10 - SM - Project44		4,720	-4,883	-163	
9729909	WG - C10 - SM - Project45		4,338	-4,581	-243	
9729910	WG - C10 - SM - Project46		6,638	-6,930	-292	
9729911	WG - C10 - SM - Project47		5,633	-6,071	-439	
9729912	WG - C10 - SM - Project48		5,896	-6,235	-339	
9729913	WG - C10 - SM - Project49		5,415	-5,680	-265	
9729914	WG - C10 - SM - Project50		4,984	-5,064	-79	
9729960	WG - C10 - SM - Project51		4,560	-4,569	-9	
9729961	WG - C10 - SM - Project52		4,991	-5,125	-135	
9729962	WG - C10 - SM - Project53		3,851	-3,953	-102	
9729963	CAISO ISP Panoche		2,876		2,876	
9730243	SFPUC - Potrero Interconnection		49,186	-150,000	-100,814	
9730361	SVP Breaker Replacement Facility Study		28,270	-20,000	8,270	
9730681	WG - ISP - Porthos		4,174	-4,174		
9730823	WAPA Lemoore NAS		8,739		8,739	
9731302	Swan Lake Affected Sys. Study		11,471		11,471	
9707780	CP-Martin 115/60 kV Upgrade Project	4,094	-3,715		-3,715	
9713955	WL - Tesla Tracy 230kV Line 1 Reloc-FAS	13,216				
9715140	WG - Rough & Ready Solar - SIS	-15,519	15,519		15,519	
9717186	WL - SVP Phase-Shifting Trans Study	-43,721		43,721	43,721	
9720462	Lathrop Irrigation District Load Study	10,808	-10,808		-10,808	
9722206	Trans Bay Cable Quick Start Study	-3,651	7,248		7,248	
9717187	WL - CA HiSpeed Train Interconnect Study	129,593	259,683	-362,428	-102,745	
9730122	HSR Interconnection -Tunnel Boring Study		1,092	-1,092		
9714755	WL - KMPUD-IFAS	63,553				
	Total Transmission	**1,853,373**	**2,839,042**	**-3,034,557**	**-195,515**	**1**

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Order	Order Description	BALANCE 12/31/2016	COSTS INCURRED PERIOD ENDED 12/31/2017	REIMBURSEMENTS RECEIVED PERIOD ENDED 12/31/2017	NET ACTIVITY PERIOD ENDED 12/31/2017
9720980	R21-Transmission DTT Study - E&J Gallo	20,000		-20,000	-20,000
9724160	R21 City of San Jose WPCP - Detailed Sty	230	-230		-230
9724403	WDT-50001 SCWA North&South Ponds Fst Trk	-31,526		31,526	31,526
9724683	TO-Green Ridge Repowering Facilities Sty	7,405			
9724703	WDT - Templeton B Energy Storage- ISP	-5,929		5,929	5,929
9724704	WDT- CE&S Dairy Biogas - Independent Sty	-3,706		3,706	3,706
9724740	50002 SCWA Ponds 1 & 2 1149-WD Supp Rev	195		-195	-195
9724742	WDT- Porter B Energy Storage - Indep Sty	-2,265		2,265	2,265
9724780	WDT - Porter Solar - Independent Study	-6,638		6,638	6,638
9724931	WDT Delano Land 1 - Fast Track Study	8,589		-8,589	-8,589
9724932	WDT Kern County Industrial 1 - Indep Sty	27,390		-27,390	-27,390
9725065	WDT - Porter B Energy Storage Deliv Sty	304		-304	-304
9725070	WDT - New Slab Creek Powerhouse Del Sty	8,247		-8,247	-8,247
9725082	1208-WD Bakersfield Indus 1 (B) Supp Rev	1,649	-1,649		-1,649
9725220	EID Powerhouse Post-COD Telecom Study	-312		312	312
9725281	Estrella Substation - Facilities Study	-6,578	5,901		5,901
9725300	ConEdison Solar Post-COD Telecom Study	62,246		-62,246	-62,246
9725380	1221-WD Burdell Solar Energy - Supp Rev	3,230		-3,230	-3,230
9725820	1207-WD Bakersfield Indus 1 (A) SIS	2,054		-2,054	-2,054
9725841	WDT- Orange Cove 2 - Fast Track	6,547		-6,547	-6,547
9725880	1227WD Black Diamond Energy Stor Sup Rev	54		-54	-54
9725900	8.4 MW Frick Wind Repower Facilities Sty	-3	3		3
9725901	2.99 MW Dyer Wind Repower Facilities Sty	-700	700		700
9725963	WDT New Slab Creek Pwrhse Facilities Sty	-6,821		6,821	6,821
9726012	WDT - Peacock Phase II - Facility Study	-13,759		13,759	13,759
9726013	WDT - 50003 SCWA R4 Fast Track Study	6,880		-6,880	-6,880
9726040	R21 Genentech - Facilities Study	-13,500		13,500	13,500
9726044	1223-RD Indian Valley Hydro - Det. Study	-4,133		4,133	4,133
9726081	WDT Collins Small Bioenergy Indep Study	4,299	563	-4,862	-4,299
9726125	GJ TeVelde Ranch Pacific Rim Detail. Sty	-4,842		4,842	4,842
9726126	WDT - DRES Quarry 2 (09_2015) Fast Track	2,199		-2,199	-2,199
9726128	R21 Hanford Renewable Energy Detail Sty	-3,475		3,475	3,475
9726129	R21 193203 Sierra Nevada Brewing Det Sty	-1,394		1,394	1,394
9726132	WDT - Castroville Energy Storage - ISP	5,920		-5,920	-5,920
9726180	R21-US Air Force Civil Engrs-Det Study	-57,102		57,102	57,102
9726300	WDT Black Diamond Energy 11_2015 F Trk	3,352		-3,352	-3,352
9726360	WDT - Bellanave Dairy Biogas - Indep Sty	2,871		-2,871	-2,871
9726361	1252-WD 50003 SCWA R4 Pond Supp Review	4,362		-4,362	-4,362
9726421	1274-WD Black Diamond Energy - Suppl Rev	-2,500		2,500	2,500
9726601	Scheid Vineyards 1258-RD Detailed Study	-3,431		3,431	3,431
9726680	Corcoran Irrig Dist (1269-RD) Det Study	-758		758	758
9726700	R21 S Joaquin Cnty (257384) Detailed Sty	-2,083		2,083	2,083
9726761	WDT- Henrietta D Energy Storage LLC ISP	-48,892	5,520	43,372	48,892
9726800	Codding Ent Ltd Ptnshp East Detailed Sty	-7,574		7,574	7,574
9726801	Codding Ent Ltd Ptnshp West Detailed Sty	-6,839	156	6,684	6,839
9727000	WDT- Bar20 Dairy Biogas ISP	-1,759		1,759	1,759
9727040	1311-WD Paso Robles Solar 1 Indep Study	-49,212		49,212	49,212
9727041	WDT Paso Robles Solar 1 FCDS Full Capac	-9,376	30,558	-21,182	9,376

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9727080	WDT - EEPV1 Supplemental Review	-814		814	814
9727121	WDT Ripon Independent Study Process	-2,699	1,963	-55,000	-53,037
9727122	WDT Ripon FCDS Full Capac Deliver Status	27,640	47,025	-87,962	-40,936
9727160	WDT - G2 Energy Ostrom Road Indep Study	-4,118	3,572	546	4,118
9727161	WDT Buck Institute Full Capacity Del Sty	-10,800		10,800	10,800
9727163	WDT Stockton RV/Boat Stg - Fast Track	3,581		-3,581	-3,581
9727164	WDT Oakley Boat RV Stg Phase II Fast Trk	3,099		-3,099	-3,099
9727180	WDT Cabrillo Wind Energy Full Capacity	379	30,683	-31,062	-379
9727181	WDT Cabrillo Wind Energy Indep Study	31,513	835	-25,000	-24,165
9727182	R21 Verwey-Madera Dairy Digester Det Sty	4,511		-4,511	-4,511
9727183	R21 Verwey-Hanford Dairy Digestr Det Sty	-2,504		3,073	3,073
9727220	1289-WD Eagle - Independent Study	1,221	303	-1,524	-1,221
9727260	R21 Van Der Kooi Dairy Digstr Detail Sty	-6,938		6,938	6,938
9727300	WDT-HZI-Waste Conn Fac SLO 4-16 Indep Sy	-1,366	2,394	419	2,813
9727460	WDT-Kern County Industrial 1 Indep Study	-1,229		1,229	1,229
9727482	R21-Lone Oak Dairy Digester-Det Study	-5,068		5,068	5,068
9727483	WDT-Coalinga Energy Storage-Indep Study	-64,086	3,282	60,804	64,086
9727484	WDT-Coalinga Energy Storage-FullCapacity	-2,989		2,989	2,989
9727520	Columbia Solar Fiber Upgrade Telecom Sty	9,427	55	-9,482	-9,427
9727580	R21 OpenSky Dairy Dgstr Genset 2 Det Sty	-6,187	311	5,875	6,187
9727620	R21Taylor Farms Enos 205445 Detailed Sty	566	2,910	-3,476	-566
9727640	WDT Oakley Boat RV Stg Phase II Supp Rev	21,087	11	-21,098	-21,087
9727641	WDT EtaGen Demo Proj - Fast Track Study	536		-536	-536
9727660	WDT- Yuba Solar Millenium Fund Fast Trk	235		-235	-235
9727663	R21 Cal Poly SLO 291865 Detailed Study	-7,381		7,381	7,381
9727740	1260-WD Collins Small Bioenergy Fac Sty	-13,283	6,786	6,497	13,283
9727780	R21 - Indian Valley Power Detailed Study	-6,926	592	6,333	6,926
9727820	WDT- Helium - Fast Track Study	562		-562	-562
9727821	WDT- Neon - Fast Track Study	-725		725	725
9727822	WDT- Argon - Fast Track Study	363		-363	-363
9727823	WDT- Xenon - Fast Track Study	1,813		-1,813	-1,813
9727824	WDT- Krypton - Fast Track Study	678		-678	-678
9727921	R21 - Celestial Valley Elec Detailed Sty	-9,853	6,364	3,490	9,853
9727922	R21 - 2143 Dacy Detailed Study	-10,800	3,664	7,136	10,800
9728040	WDT - 1358-WD Krypton - Sup Rev	-505		505	505
9728041	WDT - 1356-WD Argon - Sup Rev	-1,938		1,938	1,938
9728042	WDT - 1354-WD Helium - Sup Rev	-588		588	588
9728043	WDT-1302-WD-Bar20 Dairy Biogas-Fac Stdy	-11,342		11,342	11,342
9728080	WDT- 1355-WD Neon Supplemental Review	-1,453		1,453	1,453
9728081	WDT- 1357-WD Xenon Supplemental Review	-347		347	347
9728100	Q557 White River 2 - Facility Study	1,294		-1,294	-1,294
9728120	WDT - Radon - Fast Track Study	1,310	1,376	-2,686	-1,310
9728140	R21 Chevron 309256 NEM 2.0 Detailed Sty	-69,692	3,550	66,142	69,692
9728200	WDT- Chlorine Fast Track Study	2,415		-2,415	-2,415
9728243	WDT- Luma Hill SC1 Fast Track Study	128	1,246	-1,374	-128
9728244	WDT- PH1 Sonoma Energy Fast Track Study	1,162		-1,162	-1,162
9728402	WDT CMSA Renewable Energy Fast Track Sty	1,040		-1,040	-1,040
9728420	R21 True Leaf Farms 317838 Detailed Sty	-10,432	6,096	4,336	10,432
9728500	WDT - Apple Hill ES 1 Independent Study	-60,315	1,714		1,714
9728501	WDT - Apple Hill ES 2 Independent Study	-58,924	1,022		1,022
9728502	WDT - Apple Hill ES 1 Deliverability Sty	-10,000	11,687		11,687
9728503	WDT - Apple Hill ES 2 Deliverability Sty	-10,000	6,862		6,862
9728520	WDT West Biofuels Power Fast Track Study	-90	363	-273	90
9728521	WDT Paso Robles Solar 2 Independent Sty	-10,723	8,161	2,563	10,723
9728522	WDT Paso Robles Solar 2 Deliverab. Study	-10,000		10,000	10,000

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FOOTNOTE DATA

9728525	Friant Dam Hydro Generating Fac Post COD	13,795	1,325	-15,121	-13,795
9728527	WDT-Bodega Energy West-Fast Track Study	581		-581	-581
9728528	WDT-Petaluma Solar West-Fast Track Study	581		-581	-581
9728529	R21 Pacific Ethanol NEM 2.0 Detailed Sty	-10,800	9,779	1,021	10,800
9728580	R21 - Project Daisy Detailed Study	-10,234	7,450	2,784	10,234
9728583	WDT - 1372-WD Radon System Impact Study	-9,816	460	9,356	9,816
9728584	WDT - DRES Quarry 2.2 Fast Track Study	605		-605	-605
9728601	WDT 1384-WD CMSA Renewable Supp Review	-2,500	2,304	196	2,500
9728602	WDT 1122-WD Chevron 2MWI Supp Review	1,289		-1,289	-1,289
9728640	WDT - 7.1660 Bay - Fast Track Study	-721	121	600	721
9728641	WDT - 51.3820 Scott - Fast Track Study	-344	199	145	344
9728642	WDT - 50.2898 Jackson - Fast Track Study	-344	199	145	344
9728643	WDT - 18.3210 Gough - Fast Track Study	-344	229	115	344
9728644	WDT - 10.1690 North Point Fast Track Sty	-344	229	115	344
9728663	WDT - Poco Power - Fast Track Study	309	1,669		1,669
9728700	WDT - 50004 SCWA R5_Nov16 Fast Track Sty	-45	45		45
9728701	WDT - 50001 SCWA North/South Cluster 10	-57,422	8,718		8,718
9728761	R21 Dalena Farms 331031 NEMA 2.0 Det Sty	-10,611	1,988	8,623	10,611
9728762	R21 Sun World - Harris - Detailed Study	-10,800	1,843	8,958	10,800
9728800	R21 David Tevelde Dairy Digester Det Sty	-10,800	9,464		9,464
9728840	WDT-Rnd Valley Ind Tribes Biom Indep Sty	-10,571	2,501	8,070	10,571
9728862	Q653EA SKIC 20 Telecom Modification	2,378	2,317	-4,695	-2,378
9728863	Q885 SKIC 10 Telecom Modification	2,832	8,070	-10,902	-2,832
9728922	1357-WD Xenon Independent Study	-10,000	11,284	-1,284	10,000
9728923	WDT- Semperviren 1 Fast Track Study	-561	1,737	-1,176	561
9728961	1398-WD Bodega Energy West Suppl Review	-2,500	2,240	260	2,500
9728962	1399-WD Petaluma Solar East Suppl Review	-2,500	994	1,506	2,500
9728963	R21 Target Corp Shafter Detailed Study	-10,000	4,008		4,008
9729000	1413WD 50004 SCWA R5 Supplemental Review	-2,500	1,146	1,354	2,500
9729141	WDT - HZIU Kompogas SLO - ISP		6,570	-10,000	-3,430
9729180	R21 Charleston East 344360 NEM 2 Det Sty		9,004	-10,800	-1,796
9729200	KES Kingsburg LP -CAISO Post COD Change		42,981	-42,981	
9729240	Castroville Energy Stg 5MW Indepent Sty		6,925	-10,000	-3,075
9729241	Templeton B Energy Stg Independent Study		2,029	-2,029	
9729360	WDT - SEPV Cuyama - Fast Track Study		784	-800	-16
9729361	ZWEDC 0691-WD, CL6 Ph I&II - ISO invoice		19,170	-19,170	
9729363	R21 Musco Olive Biom Gen Jan2017 Det Sty		4,778	-4,778	
9729401	Oak Leaf X, CL6 Ph I&II - ISO invoice		19,170	-19,170	
9729402	Oak Leaf-Reedley-CL6 Ph I&II-ISO invoice		17,033	-17,033	
9729440	PorterSolarWDAT-CL8 Ph I&II-ISO invoice		3,370	-3,370	
9729460	WDT - Sirius Ph 3 Fast Track Study		1,940	-800	1,140
9729480	R21 Maddox Dairy Ph1 Enos 347251 Det Sty		5,754	-10,000	-4,246
9729481	WDT - Madera 2 Fast Tack Study		1,911	-800	1,111
9729482	WDT - Kettleman 1 Fast Track Study		403	-800	-397
9729520	R21 Berrenda Mesa Water 352031 Det Study		12,497	-58,000	-45,503
9729522	R21Beldrige Wtr Stor 352165 NEM2 Det Sty		11,110	-10,000	1,110
9729523	R21 - SCRWA - ENOS 318636 - Detailed Sty		154		154
9729524	WDT - SEPV Cuyama Supplemental Review		1,856	-2,500	-644
9729541	R21-Univ of Cal Merced 240170-Det Study		6,350	-6,350	
9729547	R21 Scheid Vineyards 352790 Detailed Sty		8,731	-8,731	
9729621	QF 19C010 Humboldt Redwood Facility Sty		3,722	-10,000	-6,278
9729681	SPI Quincy - Facilities Study		4,447	-10,000	-5,553
9729700	SPI Sonora - Facilities Study		4,497	-10,000	-5,503
9729701	WDT - NortBelridge Comm Solar Fast Track		3,952	-800	3,152
9729704	WDT - West Paso Community Solar Fast Trk		403	-800	-397

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9729760	WDT - SEPV Cuyama System Impact Study		5,995	-10,000	-4,005	
9729800	WDT - Cadet Community Solar Fast Track		1,799	-800	999	
9729801	WDT - Midway-Sunset Comm Solar Fast Trk		783	-800	-17	
9729804	R21 Premier Int Hold 361723 NEM2 Det Sty		3,382	-57,000	-53,618	
9729805	WDT - Nacimiento Interc Study 2017 Indep		12,599	-10,000	2,599	
9729806	WDT - Chevron USA Prod Co ISP		24,231	-80,000	-55,769	
9729807	WDT - Dalena Farms Cluster Study		13,706	-55,000	-41,294	
9729809	R21 River Ranch Dairy Digstr Detail Sty		4,424	-4,424		
9729810	1453-WD BUCCANEER System Impact Study		3,467	-10,000	-6,533	
9729840	WDT - Semperviren 2 Shadelands Fast Trk		1,749	-1,749		
9729844	WDT - SEPV Kings - Fast Track		635	-800	-165	
9729861	WDT-1484-WD-North Belridge Com - Sup Rev		2,825	-2,500	325	
9729920	1452-WD Madera 2 - Independent Study		381	-10,000	-9,619	
9729921	Shiloh I Wind Project Facilities Study		8,187	-10,000	-1,813	
9729923	Exchequer RAS - CAISO Post COD		9,798	-10,000	-202	
9729940	R21 Cache Creek Casino 366552 Det Study		3,949	-59,000	-55,051	
9729942	R21 Kern Oil Refining (98110) Detail Sty		4,101	-10,000	-5,899	
9729943	MMA - Q1096 Altamont-Midway - ISO 40024		268	-268		
9729944	MMA - Q1036 Mustang 2 - ISO 51601		409	-409		
9729980	MMA - Q1158 Slate - ISO 51731		1,901		1,901	
9729981	MMA-Q1036 Mustang 2-Gen-Tie-ISO 51601		1,749		1,749	
9730000	MMA - Q1011 GHS Project - ISO 51541		2,861		2,861	
9730001	MMA - Q653F SP PVUSA - COD - ISO 60192-C		400	-400		
9730002	MMA - Q356 Cuyama Solar - ISO 50297C		2,555	-2,555		
9730003	WDT - Midway Sunset Comm Solar Supp Rev		1,336	-2,500	-1,164	
9730060	MMA - QF Santa Clara Wind - 51155		2,791		2,791	
9730061	MMA - Q1096 & QF Altamont Midway - 51156		2,059		2,059	
9730062	MMA - QF Forebay Wind - 51154		1,599		1,599	
9730065	Q877 California Flats - Roadway PEIE		99,822	-672,446	-572,623	
9730066	1499-WD - Cadet Community Supp Review		2,322	-2,500	-178	
9730068	1419-RD Sandridge Ptnrs NEMA2 Det Study		6,816	-10,000	-3,184	
9730080	MMA - QF/Q955 Algonquin Sanger 2 - 51462		133	-133		
9730120	City of Wasco 370604 RESBCT Detailed Sty		3,337	-10,000	-6,663	
9730121	WDT - Kent Solar Fast Track Study		1,473	-800	673	
9730123	R21-Mariposa Biomass Prj-Detailed Study		3,616	-10,000	-6,384	
9730180	MMA - Q1011 GHS Project-Gen-Tie - 51541		86		86	
9730181	MMA - QF Oroville Cogeneration - 51158		3,721		3,721	
9730182	WDT - IP Cabernet - Fast Track		1,680	-800	880	
9730220	R21 George DeBoer Q-1432-RD Detailed Sty		3,329	-10,000	-6,671	
9730221	R21 Henry Miller Q-1433-RD Detailed Sty		3,585	-10,000	-6,415	
9730242	MMA - Q653F SP PVUSA - BESS-ISO 60192-C		1,255		1,255	
9730244	R21 Rijlaarsdam NEMA 2 1483-RD (Det Sty)		3,720	-10,000	-6,280	
9730280	MMA-Q1028&29 Ltl Bear Solar1&2-ISO 51587		2,463	-2,003	460	
9730281	WDT - CA-17-0018 SB43 MAHAL (FT)		2,005	-800	1,205	
9730304	1510-WD Semperviren 2, Shadelands - SR		235		235	
9730305	WDT IP Malbec - FT		781	-800	-19	
9730320	R21 1458-RD State Center Comm. Detailed		4,802	-10,000	-5,198	
9730340	WDT - Korbel Power (ISP)		12,848	-10,000	2,848	
9730360	Kingsburg Cogen - Facility Study		1,494		1,494	
9730382	WDT-Eurus Energy-Facility Mods Study		9,500	-30,000	-20,500	
9730420	1469-RD BELRIDGE WATER/Detailed		1,220	-10,000	-8,780	
9730421	1513-RD Sandridge Partners/Detailed		2,985	-10,000	-7,015	
9730441	R21 - Shasta Storage 1/Detailed		1,388	-60,000	-58,612	
9730480	MMA - Q1097 Bear Canyon - ISO 51783		3,307	-3,307		
9730481	R21 D ARRIGO BROS CO OF CALIF/Detailed		2,634	-10,000	-7,366	

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9730500	Kent Solar, LLC (1521-WD) - ISP		9,202	-10,000	-798	
9730540	WDT Small World Trading - FT		662	-800	-138	
9730580	WDT Semperviren 3 - FT		538	-800	-262	
9730581	R21 Avalon Dairy Digester/Detailed		1,628	-10,000	-8,372	
9730600	R21 The Wine Group LLC/Detailed			-10,000	-10,000	
9730620	WDT Peterson Road 2/FT		2,797	-800	1,997	
9730640	WDT - 50003 SCWA R4 - Independent Study		1,794	-10,000	-8,206	
9730660	WDT - CA-17-0097 SB43 Arco - ISP		1,226		1,226	
9730662	R21 - Bear Creek - EDMUD - Detailed Stdy		2,687	-10,000	-7,313	
9730664	WDT-CA-17-0101 SB43 Devils Den-Fst Trk		2,670	-800	1,870	
9730665	WDT-CA-17-0102 SB43 Gates-ISP		2,842	-10,000	-7,158	
9730666	WDT-CA-17-0106 SB43 Coalinga 1-Fst Trk		595	-800	-205	
9730667	WDT-CA-17-0122 SB43 Coalinga 2-Fst Trk		451	-800	-349	
9730668	WDT - Brilliance Solar Project - FT		367	-367		
9730672	WDT - CA-17-0018 SB43 Mahal - Sup Rev		318	-2,500	-2,182	
9730720	MMA - Q744 Redwood Solar - ISO 50857		3,435	-3,435		
9730740	CA Department of Corrections #387295/Det			-10,000	-10,000	
9730743	WDT CA-17-0100 SB43 Derrick/ISP		738	-10,000	-9,262	
9730744	WDT - American Canyon Solar A/FT		1,137	-800	337	
9730745	WDT - American Canyon Solar B/FT		85	-800	-715	
9730746	WDT - American Canyon Solar C/FT		1,287	-800	487	
9730760	R21 EBMUD Enos (387729) RESBCT/Detailed		1,342	-56,000	-54,658	
9730784	WDT SEPV American Canyon/FT		1,007	-800	207	
9730785	WDT Palm Drive Solar A/FT		857	-800	57	
9730786	WDT Palm Drive Solar B/FT		1,102	-800	302	
9730800	R21 - Bangor Solar - 1402-RD - Det Stdy			-10,000	-10,000	
9730820	WDT-CA-17-0090 SB43 Dulgarian/FT		1,033	-800	233	
9730821	WDT-Tracy Energy Storage System_8/17/ISP		1,210	-1,210		
9730822	WDT - Merced 2/FT		2,238	-800	1,438	
9730840	WDT - IP Cabernet_08_2017/FT		582	-800	-218	
9730860	MMA - Q258 Oakley - ISO 20181-C		5,051	-5,051		
9730861	R21 - City Count of SF (Enos 390303)/Det		2,005	-10,000	-7,995	
9730862	1529-RD City of Paso Robles/Detailed		3,076	-10,000	-6,924	
9730880	WDT - DRES Quarry 2.3/FT		919	-800	119	
9730881	WDT - IP Merlot 1/FT		947	-800	147	
9730882	WDT - IP Merlot 2/FT		1,235	-800	435	
9730883	WDT - IP Merlot 3/FT		1,713	-800	913	
9730920	WDT-SR Sovereign Energy Semperviren 3		433	-2,500	-2,067	
9730940	R21-Calcom Solar-Western Sky Dairy-DS		150	-1,000	-850	
9730941	R21-OpTerra-S K F Sanitation District-DS		2,900	-10,000	-7,100	
9730961	WDT - FT - San Rafael Airport Unit No. 2		1,490	-800	690	
9730962	WDT - ISP - Intersect Power - IP Porthos		3,209	-71,000	-67,791	
9730963	WDT - FT - ZGlobal - Eagle 2 Solar		1,552		1,552	
9730964	WDT - FT - Morris 385 LLC - Morris 385		1,537		1,537	
9730966	WDT - FT - El Pomar Parners - El Pomar		1,631	-800	831	
9731000	WDT-SR 1561 American Canyon Solar A		1,155	-2,500	-1,345	
9731002	WDT - SR - 1562 American Canyon Solar B		721	-2,500	-1,779	
9731003	WDT - SR - 1563 American Canyon Solar C		1,590	-2,500	-910	
9731020	R21-DS-MaasEn. Lakeside Energy Dairy Dig		455	-10,000	-9,545	
9731040	WDT-SR-Rival Power-Peterson Road 2		3,032	-2,500	532	
9731060	R21 - DS - Chowchilla Dairy Power			-10,000	-10,000	
9731061	WDT-FT-ET Solar - Midway Towers Comm Sol		601	-1,000	-399	
9731062	WDT-FT-ET Solar - East Bay Community Sol		579	-1,000	-421	
9731063	R21-DS-Sandridge Partners Etal-NEMA		644	-10,000	-9,356	
9731080	MMA - QF Altamont Frick - ISO 51135-QM		562		562	

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FOOTNOTE DATA

9731081	WDT-SR-RenewableProp-Palm Drive Solar A		1,184	-2,500	-1,316	
9731082	WDT-SR-RenewableProp-Palm Drive Solar B		1,296	-2,500	-1,204	
9731120	MMA - Q965 Java Solar - ISO 51436		1,279		1,279	
9731160	MMA-Q1109 North Central Valley-ISO 51779		295	-295		
9731181	WDT-FT-CED White River 2 Battery Storage		1,292	-1,000	292	
9731182	R21 - Musco Olive Biom Gen - Fac Study		2,129	-10,000	-7,871	
9731183	R21-DS-FoundationWindpower-Mann Packing		1,778	-10,000	-8,222	
9731187	WDT - FT - ZGlobal - Merced 2			-1,000	-1,000	
9731201	WDT - SR - IP Portfolio - IP Cabernet		781	-2,500	-1,719	
9731202	WDT - SR - IP Portfolio - IP Merlot 1		752	-2,500	-1,748	
9731203	WDT - SR - IP Portfolio - IP Merlot 2		752	-2,500	-1,748	
9731204	WDT - SR - IP Portfolio - IP Merlot 3		752	-2,500	-1,748	
9731205	WDT - SR - El Pomar Partners - El Pomar		1,662	-2,500	-838	
9731206	WDT-SR-ForeFront Power-Ava Elizabeth		1,139	-2,500	-1,361	
9731207	WDT-SR-ForeFront Power-Forefront C2		1,658	-2,500	-842	
9731208	WDT-SR-ForeFront Power-Dulgarian		1,624	-2,500	-876	
9731209	WDT - SR - San Rafael Airport Unit #2		1,045	-2,500	-1,455	
9731210	WDT - FT - Solar Electric SEPV Cuyama 2		1,310	-1,000	310	
9731211	WDT - SR - Green Light - Eagle 2 Solar		1,789	-2,500	-711	
9731280	R21-DS-BNB Renewable-Campbell Soup Supp		339	-10,000	-9,661	
9731281	R21-DS-Renewable Solar-Danell Brothers		1,654	-10,000	-8,346	
9731283	WDT - FT - SFPUC - Burton High School PV		914	-1,000	-86	
9731287	R21-DIS-Forefront-CDCR-1569-RD			-10,000	-10,000	
9731300	WDT-SR-Forefront Power-Mouren Farming		1,526	-2,500	-974	
9731301	MMA - Q1103 Central 40 - ISO 51821		858	-858		
9731320	WDT - FT - EPRI - SVUSD Bus Barn Storage		1,524	-1,000	524	
9731340	R21 - DIS - West Biofuels - SunWest Bio		378	-10,000	-9,622	
9731341	R21 - DIS - Syn Tech - Lisa Boone Harris			-10,000	-10,000	
9731360	WDT-SIS-Solar Electric-SEPV Cuyama 2		264	-10,000	-9,736	
9731382	WDT-Forefront Power-Pistachio Road		509	-10,000	-9,491	
9731383	R21-DIS-Maas Energy-Lakeshore Dairy Dig			-10,000	-10,000	
9731482	WDT - SIS - Rival Power Peterson Road 2			-10,000	-10,000	
9731484	R21 - DIS - JKB Energy-Trinitas Fund II		509	-10,000	-9,491	
9731502	MMA-Q744 Redwood Solar (Phs4)-ISO 50857		44		44	
9731503	R21-DIS-Concentric-South County Packing			-10,000	-10,000	
9731504	R21-DIS-ARC Alternatives-City of Lincoln			-10,000	-10,000	
9731519	WDT-ISP-Calbio Energy-Bar20 Dairy Biogas			-10,000	-10,000	
9731582	R21 - DIS - NRG - Calmat Co. Q#: 1593-RD			-10,000	-10,000	
9726820	R21-Livermore Community Solar Frm-Det St	11,107				
9727880	1313-RD City of Soledad REMAT Detail Sty	-4,407	2,895	1,511	4,407	
9728020	R21-Mad River Energy Co-Detailed Study	-3,239	2,439	800	3,239	
9728141	R21 Napa Recycling Biomass Detailed Sty	-8,552	156	8,396	8,552	
9728661	R21Sonoma Cty Water 1349-RD Detailed Sty	-8,827	9,559	-733	8,827	
9728980	R21-Chevron Richmond Refinery SOSS-WPA		4,477	-4,477		
9729260	R21-Kern High School-Liberty-Det Study		6,414	-6,414		
9729261	R21-Kern High School-Frontier-Det Study		8,254	-8,254		
9729922	R21 Merced County RES-BCT Detailed Study		2,424	-10,000	-7,576	
	Total Generation/Distribution	**-571,946**	**923,383**	**-1,972,783**	**-1,049,400**	**-1**

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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	AB802 Memo Account - Electric	236,044	765,086	400	675,371	325,759
2	(amortization: < 12 months)					
3	AB802 Memo Account - Gas	193,127	625,980	400	552,576	266,531
4	(amortization: < 12 months)					
5	Acc Amt - Plant RA Tax	(158,366,909)		405	3,520,572	-161,887,481
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	(604,246,723)	364,000	405	42,607,000	-646,489,723
10	(amortization: 12 years)					
11	AMCDOP- Cost Adjust Mechanism		66,372,533		16,526,044	49,846,489
12	(amortization: < 12 months)					
13	Balancing Account - Utility Generation	47,806,276	3,000,269,148	400	3,061,933,348	-13,857,924
14	(amortization: < 12 months)					
15	BCA Charge Account	3,723,827	1,712,394	400	4,995,963	440,258
16	(amortization: <12 months)					
17	Biomass Memo Account		815,966		458,058	357,908
18	Bioram Memo Account		6,513,497		737,771	5,775,726
19	CA Alternate Rates for Energy Program-Electric	17,754,685	543,435,657	400	537,751,426	23,438,916
20	(amortization: < 12 months)					
21	CA Alternate Rates for Energy Program-Gas	(14,267,977)	127,871,156	400	135,509,419	-21,906,240
22	(amortization: < 12 months)					
23	CA Solar Initiative Thermal Program Memo Account	9,349,904	6,465,158	400	9,072,947	6,742,115
24	(amortization: < 12 months)					
25	Catastrophic Event Memorandum Account	125,787,680	408,071,430	182.3	5,935,419	527,923,691
26	(amortization: <12 months)					
27	CEE Incentive Electric Balancing Account	17,363,645		400	14,892,315	2,471,330
28	(amortization: < 12 months)					
29	CEE Incentive Gas Balancing Account	2,313,793		400	2,101,414	212,379
30	(amortization: < 12 months)					
31	Core Brokerage Fee	1,464,404	6,502,549		6,783,150	1,183,803
32	Amortization : < 12 MONTHS					
33	Core Fixed Cost Gas Balancing Account	362,411,026	3,008,337,071	400	3,082,364,454	288,383,643
34	(amortization: < 12 months)					
35	Core Pipeline Demand Charge Account	12,436,390	480,839,462	400	480,331,226	12,944,626
36	(amortization: < 12 months)					
37	Critical Docs Program memo Acct NC		12,679,891	182.3	6,418,923	6,260,968
38	(amortization: > 12 months)					
39	Deferred Debit - Gas Reserves (Contra Balancing Ac	(345,369,781)	202,448,988	400	63,229,808	-206,150,601
40	(amortization: < 12 months)					
41	Demand Response Expenditures B/A (DREBA)	(869,260)	2,410,555	400	9,426,154	-7,884,859
42	amortization: < 12 months					
43	Department of Energy Litigation Balancing Account	(28,180,867)	28,206,456	182.3	15,042,672	-15,017,083
44	TOTAL	9,306,684,417	27,105,485,589		31,393,369,213	5,018,800,793

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	03/09/2018	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (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	Diablo Canyon Seismic Studies Balancing Acct	19,434,196	4,955,100	182.3	7,029,011	17,360,285
3	(amortization: < 12 months)					
4	Distribution Revenue Adjustment Mechanism	131,897,336	5,971,037,151	400	6,174,849,709	-71,915,222
5	(amortization: < 12 months)					
6	DWR Power Charge Collection Balancing Account	(3,349,525)	2,325,973	182.3	146,981	-1,170,533
7	(amortization: < 12 months)					
8	Dynamic Pricing Memorandum Account	510,194	5,198	182.3		515,392
9	(amortization: < 12 months)					
10	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
11	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
12	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
13	Electric Balancing Account Reserve Account	(237,926,773)	39,577,076	400	508,751,412	-707,101,109
14	(amortization: < 12 months)					
15	Electric Hazardous Substance Balancing Account	20,199,053	56,603,191	182.3	41,027,051	35,775,193
16	(amortization: < 12 months)					
17	Electric Price Risk Management - Current	37,060,334	168,900,034	555	162,280,005	43,680,363
18	Electric Price Risk Management - NonCurrent	92,254,861	320,328,257	555	347,695,249	64,887,869
19	Electric Program Investment Charge	3,502,881	149,987,575	400	149,186,585	4,303,871
20	(amortization: < 12 months)					
21	End-Use Customer Refund Adjustment	(1,329,667)	102,732,251	400	120,126,894	-18,724,310
22	(amortization: < 12 months)					
23	Energy Recovery Bonds Balancing Account	(507,115)	16,680,962	400	19,946,632	-3,772,785
24	(amortization: < 12 months)					
25	Energy Resource Recovery Account	96,753,559	4,002,735,596	400	4,028,897,393	70,591,762
26	(amortization: < 12 months)					
27	Environmental Compliance	147,817,172	52,281,741	182.3	40,939,314	159,159,599
28	(amortization: 32 years)					
29	Environmental Compliance Non-HSM	33,806,661	13,209,613	228.4	6,027,225	40,989,049
30	(amortization: 32 years)					
31	Family Electric Rate Assistance Balancing Acct	5,564,978	6,396,585	400	5,565,438	6,396,125
32	(amortization: < 12 months)					
33	FIN 47 - Regulatory Asset	17,674,881	2,733,462	101	2,850,307	17,558,036
34	Financing Costs - Current	1,625,224		428	117,994	1,507,230
35	(amortization: < 12 months)					
36	Financing Costs Regulatory Asset	18,434,407	117,994	428	1,526,896	17,025,505
37	(amortization: 20 years)					
38	Fire Hazard Prevention Memo Acct	661,110	1,172,891	182.3	755,156	1,078,845
39	(amortization: < 12 Months)					
40	Gas Core Firm Storage Account	2,952,593	71,538,223	400	71,654,774	2,836,042
41	(amortization: < 12 months)					
42	Gas Hazardous Substance Balancing Account	46,825,803	131,768,793	182.3	95,119,148	83,475,448
43	(amortization: < 12 months)					
44	TOTAL	9,306,684,417	27,105,485,589		31,393,369,213	5,018,800,793

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	03/09/2018	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (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	Gas Hazardous Substance Regulatory Asset	344,906,734	125,762,750	182.3	95,525,066	375,144,418
2	(amortization: 32 years)					
3	Gas Non-Hazardous Substance Regulatory Asset	131,678,680	3,692,617	228.4	1,837,387	133,533,910
4	(amortization: 32 years)					
5	Gas Pipeline Expense and Capital Balancing Account	2,419,848	3,671,288	400	2,655,088	3,436,048
6	(amortization: <12 months)					
7	Gas Price Risk Management - Current	1,339,861	4,498,735	807	4,754,419	1,084,177
8	GPBA-Greenhouse Gas Compliance Subaccount	89,683,390	73,625,417	400	6,107,186	157,201,621
9	(amortization: < 12 months)					
10	Gas Public Purpose Program Surcharge Memo Acct	47,168,269	281,053,708	186	282,837,983	45,383,994
11	(amortization: < 12 months)					
12	Gas Transmission and Storage Memo Account	455,802,166	294,338,915	400	465,819,125	284,321,956
13	(amortization: < 12 months)					
14	Gas Transmission and Storage Revenue Sharing Mech.	(45,937,691)	444,929,276	400	380,847,980	18,143,605
15	(amortization: < 12 months)					
16	GPBA - GHG Operational Cost Subaccount	14,179,365	13,227,080	400		27,406,445
17	(amortization: < 12 months)					
18	Green Tariff Shared Renewables Bal Acct	95,486	4,913,976	400	4,903,415	106,047
19	(amortization: < 12 months)					
20	Greem Tariff Shared Renewables Memo Acct	4,184,401	1,135,997	400	323,928	4,996,470
21	(amortization: < 12 months)					
22	Greenhouse Gas Expense Memo Account - E	(2,921,352)	1,335,531	400	306,576	-1,892,397
23	Greenhouse Gas Expense Memo Account - G	285,925	54,999	400	6,065	334,859
24	(amortization: < 12 months)					
25	Hydro Licensing Balancing Account	(47,587,191)	56,132,190	182.3	28,917,842	-20,372,843
26	(amortization: > 12 months)					
27	Land Conserv. Plan Env. Remediation Memo Acct.	3,286,707	752,559	182.3	3,292,885	746,381
28	(amortization: < 12 months)					
29	Line 407 Memo Acct NC		301,110	182.3		301,110
30	(amortization: > 12 months)					
31	Major Emergency Balancing Account	1,239,340	282,171,271	182.3	283,121,901	288,710
32	(amortization: < 12 Months)					
33	Market Redesign & Technology Memo Account	743,592	7,576	182.3		751,168
34	(amortization: < 12 months)					
35	Miscellaneous Electric Reg Asset - Current	276,626,282	204,620,633	Various	205,080	481,041,835
36	(amortization: < 12 months)					
37	Miscellaneous Electric Reg Asset - NonCurrent	2,266,595	8,782,839	549	1,410,757	9,638,677
38	(amortization: 25 years)					
39	Miscellaneous Gas Reg Asset - Current	24,889,346	8,944,742	Various	29,968,329	3,865,759
40	(amortization: < 12 months)					
41	Mobile Home Park Balancing Account - Electric	1,878,629	9,459,914	182.3	4,245,054	7,093,489
42	(amortization: < 12 months)					
43	Mobile Home Park Balancing Account - Gas	2,097,041	10,112,530	182.3	4,939,669	7,269,902
44	TOTAL	9,306,684,417	27,105,485,589		31,393,369,213	5,018,800,793

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	Modified transition cost balancing account	(9,782,643)	92,345,403	400	93,371,735	-10,808,975
3	(amortization: < 12 months)					
4	Negative Ongoing Competition Transition Chrg BA	3,006,291,549	92,495,664	182.3	9,118,921	3,089,668,292
5	(amortization: < 12 months)					
6	New System Generation BA	69,706	162,895,889	400	209,615,611	-46,650,016
7	(amortization: < 12 months)					
8	Non Current HSM BA Elec	36,041,872	84,841,106	182.3	82,443,703	38,439,275
9	(amortization: > 12 months)					
10	Non Current HSM BA Gas	84,097,702	197,962,579	182.3	192,368,640	89,691,641
11	(amortization: > 12 months)					
12	Nuclear Decommissioning Adjustment Mechanism	18,494,400	84,711,326	400	148,958,514	-45,752,788
13	(amortization: 2 years)					
14	Nuclear Regulatory Commission Rulemaking Costs BA	(11,570,309)	73,005,750	182.3	53,433,974	8,001,467
15	(amortization: > 12 Months)					
16	Pension Regulatory Asset	2,428,747,332	92,232,360	926	567,015,700	1,953,963,992
17	(amortization: indefinite)					
18	Procurement Energy Efficiency Rev. Adj. Mechanism	(24,212,281)	382,442,431	400	346,626,662	11,603,488
19	(amortization: < 12 months)					
20	Public Purpose Programs Revenue Adjustment Mech.	(9,623,156)	202,313,396	400	219,410,448	-26,720,208
21	(amortization: < 12 months)					
22	Purchased Gas Balancing Account	2,028,376	1,843,947,515	400	1,843,856,632	2,119,259
23	(amortization: < 12 months)					
24	Reg Asset - Abandoned Capital Projects	12,801,766	11,029,329	400	5,506,860	18,324,235
25	(amortization: < 12 months)					
26	Reg Asset - Mobilehome park BA - E Noncurrent	8,337,725	16,013,416	597	9,233,855	15,117,286
27	(amortization: < 12 months)					
28	Reg Asset - Mobilehome park BA - G Noncurrent	6,981,112	19,577,798	893	9,083,306	17,475,604
29	(amortization: < 12 months)					
30	Reg Asset - Mobilehome park BA - E Current	579,167	2,965,218	597	1,921,906	1,622,479
31	(amortization: < 12 months)					
32	Reg Asset - Mobilehome park BA - G Current	468,261	3,162,082	893	1,823,435	1,806,908
33	(amortization: < 12 months)					
34	Reg Asset - Hydro Non Current		10,758,023	400		10,758,023
35	(amortization: > 12 months)					
36	Reg Asset - Cema Elec Non Current	143,968,295	236,064,138	588	57,982,993	322,049,440
37	(amortization: > 12 months)					
38	Reg Asset - Cema Gas Non Current		29,653,150	400	3,223,678	26,429,472
39	(amortization: > 12 months)					
40	Reliability Services Balancing Account	(4,595,581)	4,556,556	400	371,791	-410,816
41	(amortization: < 12 months)					
42	Renewables Portfolio Standard Cost Memo Acct	280,274	2,856	400		283,130
43	(amortization: < 12 months)					
44	TOTAL	9,306,684,417	27,105,485,589		31,393,369,213	5,018,800,793

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	03/09/2018	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (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	Residential Rate Reform Memorandum Account (RRRMA)	20,790,888	19,793,711	182.3	21,330,659	19,253,940
2	(amortization: < 12 months)					
3	Smart Grid Memo Acct	885,696	97,331	182.3	887,014	96,013
4	(amortization: < 12 Months)					
5	Tax Normalization Memo Account (TNMA)		9,965,012	400		9,965,012
6	(amortization: > 12 months)					
7	Transition Cost - Noncore Balancing Account	(3,349,458)	156,222,842	400	155,187,959	-2,314,575
8	(amortization: < 12 months)					
9	Transmission Access Charge Balancing Account	243,770,688	424,722,625	400	529,483,172	139,010,141
10	(amortization: < 12 months)					
11	Transmission Integrity Mgmt Balancing Account	173,852,833	57,886,682	182.3	115,882,522	115,856,993
12	(amortization: > 12 months)					
13	Transmission Revenue Balancing Account	(93,544,387)	196,626,567	400	204,112,329	-101,030,149
14	(amortization: < 12 months)					
15	Unamortized Financial Hedging Cost	13,616,039		428	836,195	12,779,844
16	(amortization: 20 years)					
17	Unamortized Financial Hedging Cost Current	836,195		428		836,195
18	(amortization: < 12 months)					
19	URG Plant Regulatory Asset - current	43,335,000			1,096,000	42,239,000
20	(amortization: < 12 months)					
21	URG Plant Regulatory Asset - noncurrent	943,709,000	1,096,000			944,805,000
22	(amortization: 22 years)					
23	URG Plant Regulatory Asset - Tax	183,010,953				183,010,953
24	(amortization: 11 years)					
25	Vegetation Management Reg. Asset - Current	13,801,008	81,577,650	400	79,530,578	15,848,080
26	(amortization: < 12 months)					
27						
28	Miscellaneous minor items	3,881,318,947	1,661,200,888	Various	5,542,269,482	250,353
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43						
44	TOTAL	9,306,684,417	27,105,485,589		31,393,369,213	5,018,800,793

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 232.1 Line No.: 10 Column: b

The FERC software will not allow the entire beginning balance of Electric Balancing Account Reserve Account of ($3,237,926,770) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 10: ($999,999,999)
Line 11: ($999,999,999)
Line 12: ($999,999,999)
Line 13: ($237,926,773)
Total ($3,237,926,770)

Schedule Page: 232.1 Line No.: 10 Column: f

The FERC software will not allow the entire ending 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 10: ($999,999,999)
Line 11: ($999,999,999)
Line 12: ($999,999,999)
Line 13: ($707,101,109)
Total ($3,707,101,106)

Schedule Page: 232.2 Line No.: 39 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: 232.4 Line No.: 28 Column: d

Primarily Integrated Distribution Energy resources and Land Coversation Plan Implementation account, offset to 400 and 182.3, respectively.

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	03/09/2018	End of 2017/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Undistributed Charges	-3,432,412	1,009,900,102	VARIOUS	1,017,224,115	-10,756,425
2	Customer Adv for Construction	8,093,319	1,279,641	VARIOUS	2,095,345	7,277,615
3	Development Costs	52,464,087	56,926,689	131	47,155,488	62,235,288
4	Payments for MLX and					
5	Non-Energy Invoices	1,537,014	602,111,741	VARIOUS	602,278,199	1,370,556
6	Payments for Main Line					
7	Extension	-3,906,245	133,621,503	VARIOUS	136,026,584	-6,311,326
8	Clearing Account for					
9	JP Morgan Chase	1,311,440	20,848,906	VARIOUS	20,889,219	1,271,127
10	Payroll Clearing Account	263,924	12,594,749,287	VARIOUS	12,594,811,705	201,506
11	Land Surplus		518,125	930.2	37,906	480,219
12	Credit Card Clearing Account	-87,752	7,840,886	VARIOUS	8,028,433	-275,299
13	Miscellaneous minor items	1,555,256	540,074,221	VARIOUS	541,571,074	58,403
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	57,798,631				55,551,664

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	03/09/2018	2017/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.: 11 Column: b

FY16 end of year balance $0 previously disclosed within the miscellaneous minor items row. End of year 2017 balance exceeds the $100,000 threshold for miscellaneous minor items. As such, land surplus is being disclosed separately in 2017.

Schedule Page: 233 Line No.: 12 Column: b

FY16 end of year balance -$87,752 previously disclosed within the miscellaneous minor items row. End of year 2017 balance exceeds the $100,000 threshold for miscellaneous minor items. As such, credit card clearing account is being disclosed separately in 2017.

Schedule Page: 233 Line No.: 12 Column: d

Typical Accounts charged: 131

Schedule Page: 233 Line No.: 13 Column: b

FY17 beginning of year balance does not include -$87,752 for the credit card clearing account balance that was previously disclosed within the miscellaneous minor items row. The credit card clearing account end of year 2017 balance exceeds the $100,000 threshold for miscellaneous minor items and as such, this item is being disclosed separately in 2017. See note on line 9, column b.

Additionally, the FY17 beginning of year balance includes $259,390 for interest on commercial paper and $1,281,426 for reimburseable transmission service generation interconnection study costs as the end of year 2017 balances do not exceed the $100,000 threshold for miscellaneous minor items.

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

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	-133,488,724	-93,803,083
3	Compensation	52,955,235	94,297,980
4	CIAC	-200,844,330	-146,286,875
5	Injuries and Damages	186,135,579	102,846,333
6	California Corporation Franchise Tax	221,309,584	161,001,489
7	Other	243,478,691	-170,762,620
8	TOTAL Electric (Enter Total of lines 2 thru 7)	369,546,035	-52,706,776
9	Gas		
10	Environmental	-53,336,878	-57,056,261
11	Compensation	35,556,031	45,329,183
12	CIAC	300,896,855	204,929,511
13	Injuries and Damages	-82,309,688	-54,950,921
14	California Corporation Franchise Tax	-23,660,612	-26,584,707
15	Other	1,578,741,423	1,223,174,711
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,755,887,131	1,334,841,516
17	Other (Specify)	424,027,365	446,026,682
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,549,460,531	1,728,161,422

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	(84,916,857)	(42,937,411)
Compensation	3,376,290	3,352,706
Other	505,567,932	485,611,387
Total	424,027,365	446,026,682

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	03/09/2018	End of 2017/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				
40				
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

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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.

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	6,684,587,624
3	Excess Tax Benefit on Stock Based Compensation	50,960,304
4		
5		
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40	TOTAL	6,735,547,928

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

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 5.625% Senior Notes due 2017	5.625%	500,000,000	3,857,481
9				2,710,000 D
10	Series 5.625% Senior Notes due 2017	5.625%	200,000,000	1,486,541
11				-3,100,000 P
12	Series 6.35% Senior Notes due 2038	6.350%	400,000,000	3,943,976
13				568,000 D
14	Series 8.25% Senior Notes due 2018	8.250%	600,000,000	4,572,075
15				9,942,000 D
16	Series 8.25% Senior Notes due 2018	8.250%	200,000,000	1,511,598
17				-8,950,000 P
18	Series 6.25% Senior Notes due 2039	6.250%	550,000,000	5,145,853
19				6,814,500 D
20	Series 5.4% Senior Notes due 2040	5.400%	550,000,000	5,435,842
21				7,815,500 D
22	Series 5.8% Senior Notes due 2037	5.800%	250,000,000	2,562,097
23				3,862,500 D
24	Series 3.5% Senior Notes due 2020	3.500%	550,000,000	4,205,770
25				2,728,000 D
26	Series 3.5% Senior Notes due 2020	3.500%	250,000,000	1,897,267
27				6,840,000 D
28	Series 5.4% Senior Notes due 2040	5.400%	250,000,000	2,459,767
29				6,252,500 D
30	Series 4.25% Senior Notes due 2021	4.250%	300,000,000	2,270,404
31				243,000 D
32	Series 3.25% Senior Notes due 2021	3.250%	250,000,000	1,981,515
33	TOTAL		19,477,100,000	269,312,417

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	03/09/2018	End of 2017/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			1,312,500 D
2	Series 4.5% Senior Notes due 2041 4.50%	250,000,000	2,576,302
3			862,500 D
4	Series 4.45% Senior Notes due 2042 4.45%	400,000,000	4,062,665
5			2,036,000 D
6	Series 2.45% Senior Notes due 2022 2.45%	400,000,000	3,251,743
7			1,164,000 D
8	Series 3.75% Senior Notes due 2042 3.75%	350,000,000	3,632,775
9			311,500 D
10	Series 3.25% Senior Notes due 2023 3.25%	375,000,000	2,924,964
11			1,901,250 D
12	Series 4.6% Senior Notes due 2043 4.60%	375,000,000	3,768,714
13			303,750 D
14	Series 3.85% Senior Notes due 2023 3.85%	300,000,000	2,505,170
15			543,000 D
16	Series 5.125% Senior Notes due 2043 5.125%	500,000,000	5,099,524
17			765,000 D
18	Series 3.75% Senior Notes due 2024 3.75%	450,000,000	3,672,801
19			445,500 D
20	Series 4.75% Senior Notes due 2044 4.75%	450,000,000	4,685,300
21			1,921,500 D
22	Series 3.4% Senior Notes due 2024 3.40%	350,000,000	2,788,492
23			262,500 D
24	Series 4.75% Senior Notes due 2044 4.75%	225,000,000	2,298,853
25			-13,594,500 P
26	Series 4.3% Senior Notes due 2045 4.30%	500,000,000	5,051,799
27			5,745,000 D
28	Series 3.50% Senior Notes due 2025 3.50%	400,000,000	3,471,059
29			2,540,000 D
30	Series 4.30% Senior Notes due 2045 4.30%	100,000,000	1,092,707
31			5,231,000 D
32	Series 3.50% Senior Notes due 2025 3.50%	200,000,000	1,709,814
33	TOTAL	19,477,100,000	269,312,417

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	03/09/2018	End of 2017/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			-2,716,000 P
2	Series 4.25% Senior Notes due 2046 4.25%	450,000,000	4,859,582
3			8,415,000 D
4	Series 2.95% Senior Notes due 2026 2.95%	600,000,000	5,241,785
5			1,596,000 D
6	Series 4.00% Senior Notes due 2046 4.00%	400,000,000	4,345,973
7			7,344,000 D
8	Series 4.00% Senior Notes due 2046 4.00%	200,000,000	2,102,746
9			4,136,000 D
10	Series 3.30% Senior Notes due 2027 3.30%	400,000,000	3,306,994
11			1,420,000 D
12	Series 3.30% Senior Notes due 2027 3.30%	1,150,000,000	9,322,742
13			3,404,000 D
14	Series 3.95% Senior Notes due 2047 3.95%	850,000,000	8,803,613
15			3,706,000 D
16	Pollution Control Bonds		
17	1996 Series C/E/F Various	465,000,000	2,485,410
18	1997 Series B Various	148,550,000	886,179
19	2004 Series A-D 4.750%	345,000,000	1,818,863
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	19,477,100,000	269,312,417
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	19,477,100,000	269,312,417

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	03/09/2018	End of 2017/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						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
12/4/07	11/30/17	12/4/07	11/30/17		25,703,125	8
						9
3/3/08	11/30/17	3/3/08	11/30/17		10,281,250	10
						11
3/3/08	2/15/38	3/3/08	2/15/38	400,000,000	25,400,000	12
						13
10/21/08	10/15/18	10/21/08	10/15/18	200,000,000	49,316,667	14
						15
11/18/08	10/15/18	11/18/08	10/15/18	200,000,000	16,500,000	16
						17
3/6/09	3/1/39	3/6/09	3/1/39	550,000,000	34,375,000	18
						19
11/18/09	1/15/40	11/18/09	1/15/40	550,000,000	29,700,000	20
						21
4/1/10	3/1/37	4/1/10	3/1/37	250,000,000	14,500,000	22
						23
9/15/10	10/1/20	9/15/10	10/1/20	550,000,000	19,250,000	24
						25
11/18/10	10/1/20	11/18/10	10/1/20	250,000,000	8,750,000	26
						27
11/18/10	1/15/40	11/18/10	1/15/40	250,000,000	13,500,000	28
						29
5/13/11	5/15/21	5/13/11	5/15/21	300,000,000	12,750,000	30
						31
9/12/11	9/15/21	9/12/11	9/15/21	250,000,000	8,125,000	32
				18,032,100,000	806,055,299	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12/1/11	12/15/41	12/1/11	12/15/41	250,000,000	11,250,000	2
						3
4/16/2012	4/15/42	4/16/12	4/15/42	400,000,000	17,800,000	4
						5
8/16/12	8/16/22	8/16/12	8/16/22	400,000,000	9,800,000	6
						7
8/16/12	8/16/42	8/16/12	8/16/42	350,000,000	13,125,000	8
						9
6/14/13	6/15/23	6/14/13	6/15/23	375,000,000	12,187,500	10
						11
6/14/13	6/15/43	6/14/13	6/15/43	375,000,000	17,250,000	12
						13
11/12/13	11/15/23	11/12/13	11/15/23	300,000,000	11,550,000	14
						15
11/12/13	11/15/43	11/12/13	11/15/43	500,000,000	25,625,000	16
						17
2/21/14	2/15/24	2/21/14	2/15/24	450,000,000	16,875,000	18
						19
2/21/14	2/15/44	2/21/14	2/15/44	450,000,000	21,375,000	20
						21
8/18/14	8/15/24	8/18/14	8/15/24	350,000,000	11,900,000	22
						23
8/18/14	2/15/44	8/18/14	2/15/44	225,000,000	10,687,500	24
						25
11/6/14	3/15/45	11/6/14	3/15/45	500,000,000	21,500,000	26
						27
6/12/15	6/15/25	6/12/15	6/15/25	400,000,000	14,000,000	28
						29
6/12/15	3/15/45	6/12/15	3/15/45	100,000,000	4,300,000	30
						31
11/5/15	6/15/25	11/5/15	6/15/25	200,000,000	7,000,000	32
				18,032,100,000	806,055,299	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	03/09/2018	End of 2017/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
11/5/15	3/15/46	11/5/15	3/15/46	450,000,000	19,125,000	2
						3
3/1/16	3/1/26	3/1/16	3/1/26	600,000,000	17,700,000	4
						5
12/1/16	12/1/46	12/1/16	12/1/46	400,000,000	16,000,000	6
						7
3/10/17	12/1/46	3/10/17	12/1/46	200,000,000	6,466,667	8
						9
3/10/17	3/15/27	3/10/17	3/15/27	400,000,000	10,670,000	10
						11
11/29/17	12/1/27	11/29/17	12/1/27	1,150,000,000	3,373,333	12
						13
11/29/17	12/1/47	11/29/17	12/1/47	850,000,000	2,984,444	14
						15
						16
5/23/96	11/1/26	5/23/96	11/1/26	465,000,000	3,085,876	17
9/16/97	11/1/26	9/16/97	11/1/26	148,550,000	1,115,771	18
6/29/04	12/1/23	6/29/04	12/1/23		6,828,125	19
6/15/17	Various	6/15/17	Various	95,000,000	733,639	20
9/1/09	11/1/26	9/1/09	11/1/26	148,550,000	1,020,013	21
6/15/17	11/1/26	6/15/17	11/1/26	50,000,000	476,389	22
				18,032,100,000	806,055,299	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				18,032,100,000	806,055,299	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	03/09/2018	2017/Q4

FOOTNOTE DATA

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.: 8 Column: i

Interest expense is different from prior year due to the maturity of debt in Nov 2017 (11 months of interest expense).

Schedule Page: 256 Line No.: 10 Column: i

Interest expense is different from prior year due to the maturity of debt in Nov 2017 (11 months of interest expense).

Schedule Page: 256 Line No.: 12 Column: i

Interest Expense is different from prior year due to 2016 true up adjustment.

Schedule Page: 256 Line No.: 14 Column: i

Interest Expense is different from prior year due to $400M partial redemption in Nov 2017.

Schedule Page: 256.1 Line No.: 2 Column: i

Interest Expense is different from prior year due to 2016 true up adjustment.

Schedule Page: 256.1 Line No.: 6 Column: i

Interest Expense is different from prior year due to 2016 true up adjustment.

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

Interest Expense is different from prior year due to 2016 true up adjustment.

Schedule Page: 256.2 Line No.: 4 Column: i

Interest Expense is different from prior year due to 10 months of interest expense in 2016 (issued in March 2016).

Schedule Page: 256.2 Line No.: 6 Column: i

Interest Expense is different from prior year due to 1 month of interest expense in 2016 (issued in Dec 2016).

Schedule Page: 256.2 Line No.: 8 Column: a

Refer to Note 6 on page 109, for CPUC authorization number and date.

Schedule Page: 256.2 Line No.: 10 Column: a

Refer to Note 6 on page 109, for CPUC authorization number and date.

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.: 19 Column: a

In June 2017, the Utility repurchased and retired $345 million principal amount of Pollution Control Bonds series 2004 A-D.

Schedule Page: 256.2 Line No.: 23 Column: i

This amount reconciles to Account 427, Interest on Long-Term Debt, per line 62, Column C of Form 1 page 117, Statement of Income for the Year, as follows:

Interest expense per this page	$806,055,299
Remarketing Costs not included in this page	$ 10,588
Total Interest Expense per page 117	$806,065,887

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	03/09/2018	End of 2017/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	1,691,270,758
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions In Aid of Construction	212,960,965
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	373,196,412
11	Provision for State Income Taxes	53,623,954
12	Balancing Accounts	182,118,159
13	Per attached schedule (See page 261-1)	1,264,567,556
14	Income Recorded on Books Not Included in Return	
15	AFUDC - Equity and debt	126,930,664
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Per attached schedule (See page 261-1)	2,410,460,615
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	1,240,346,525
28	Show Computation of Tax:	
29	Federal Tax Net Income as above $	
30	Tax at 35% for Electric, Water. Non-Utility, and Gas	434,121,284
31	Other	
32	Add: Tax on FIN 48 Interest	14,442
33	Less: Research & Development Credits	-4,700,000
34	Less: Motor Vehicle Credit	-500,000
35	Specified Liability Loss	-10,100,653
36	Utilization of Net Operating Loss Carryover	-357,353,039
37		
38	Subtotal Tax	61,482,034
39	FIN 48 Tax Adjustments (Net to Gross)	-152,000
40	Total Tax	61,330,034
41		
42	Federal Income Tax Accrual	61,330,034
43		
44		

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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

Annual Report of PACIFIC GAS AND ELECTRIC COMPANY
Year Ended December 31, 2017

Deductions recorded on books not deducted on return:	Tax addback
Executive Compensation	1,847,054
Compensation Related Adjustments	210,831,380
Bad Debts	$ 6,000,039
Meals & Entertainment & Lobbying	9,000,000
Capitalized Interest	84,759,856
Nuclear Fuel expense	123,258,252
GHG Allowances	501,036,703
Property Tax & State Income Tax	220,361,862
Nuclear Decom Trust Book Expense	68,280,210
Frement Lease	30,000,000
Plant Disallowance	5,002,877
Other	4,189,323
Total	$ 1,264,567,556

Deductions on return not charged against book income:	Tax deduct
Computer Software	(110,469,033)
Cost of removal	(333,533,380)
Depreciation adjustment	(173,057,378)
Fossil Decommissioning	(72,230,720)
Penalties	23,576,424
DOE Settlement	(100,842,762)
Earnings of Subsidiaries	(199,029)
Section 263A MSCM	(134,000,000)
Repairs	(1,349,156,975)
Loss on Reacquired Debt	(2,166,429)
Injuries & Damages	(68,300,889)
Environmental Cleanup	(74,492,865)
Gas Hedge Amortization	(12,047,579)
Dividends Paid Deduction	(3,540,000)
Total	$ (2,410,460,615)

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

See footnote in row 13, column (b)

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	03/09/2018	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal - FICA	12,756,798		109,649,618	110,199,451	
2	Federal - Taxes on Income	45,827,420		61,330,034	-184,292,308	10,253,000
3	Federal - Unemployment	3,407,995		4,952,206	4,485,347	
4	Federal - Decommisioning			30,229,592	30,229,592	
5						
6	SUBTOTAL FEDERAL	61,992,213		206,161,450	-39,377,918	10,253,000
7						
8	State - Taxes on Income	82,884,420		68,921,904	21,898,357	-17,977,459
9	State - Unemployment	165,388		8,972,152	9,046,929	
10						
11	SUBTOTAL STATE TAXES	83,049,808		77,894,056	30,945,286	-17,977,459
12						
13	Ad Valorem property	1,103		417,569,643	437,389,643	19,820,000
14	Other	1,979,914		21,746,644	20,136,578	
15						
16	SUBTOTAL OTHER TAXES	1,981,017		439,316,287	457,526,221	19,820,000
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	147,023,038		723,371,793	449,093,589	12,095,541

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	03/09/2018	End of 2017/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
12,206,965		79,300,851			30,348,767	1
301,702,762		-10,252,653			71,582,687	2
3,874,854		3,380,254			1,571,952	3
		30,229,592				4
						5
317,784,581		102,658,044			103,503,406	6
						7
111,930,507		105,092,579			-36,170,990	8
90,611		6,443,864			2,528,288	9
						10
112,021,118		111,536,443			-33,642,702	11
						12
1,103		314,842,534			102,727,109	13
3,589,980		14,887,384			6,859,260	14
						15
3,591,083		329,729,918			109,586,369	16
						17
						18
						19
						20
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						33
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						39
						40
433,396,782		543,924,405			179,447,073	41

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

FOOTNOTE DATA

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	30,348,767	0	30,348,767
Federal - Taxes on Income	0	71,582,687	71,582,687
Federal - Unemployment	1,571,952	0	1,571,952
Total Federal taxes	31,920,719	71,582,687	103,503,406
State - Taxes on Income (a)	3,704,253	-39,875,243	-36,170,990
State - Unemployment	2,528,288	0	2,528,288
Total State	6,232,541	-39,875,243	-33,642,702
Ad Valorem property	102,364,739	362,370	102,727,109
Other	6,859,260	0	6,859,260
Total Other	109,223,999	362,370	109,586,369

(a) Rounding difference of $648 to Page 114-117.

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

Adjustment relates to FIN 48 and Balance Sheet reclasses

Schedule Page: 262 Line No.: 8 Column: f

Adjustment relates to FIN 48 and Balance Sheet reclasses

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%	106,851,545			411.5	13,526,440	
6							
7							
8	TOTAL	106,851,545				13,526,440	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	10%	21,560,294			411.5	851,609	
12							
13	TOTAL	21,560,294				851,609	
14							
15							
16							
17							
18							
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47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
93,325,105	18		5
			6
			7
93,325,105			8
			9
			10
20,708,685	22		11
			12
20,708,685			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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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	03/09/2018	End of 2017/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	CIAC Deferred Revenue	145,733,252	143, 146, 45	51,204,386	56,199,278	150,728,144
2						
3	Deferred Cr - Electric Reserves	42,973,749	182, 232, 92		1,676,280	44,650,029
4						
5	Other	23,548,528	Various	38,823,653	27,991,286	12,716,161
6						
7						
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46						
47	TOTAL	212,255,529		90,028,039	85,866,844	208,094,334

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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 (< 208,094,334 * 5% = 10,404,717).

Schedule Page: 269 Line No.: 5 Column: b

The FY17 beginning of year balance includes $14,537,652 of deferred rent, separately disclosed in 2016, as the end of year 2017 balances does not exceed 5% of the year end balance (< 208,094,334 *5% = 10,404,717).

Schedule Page: 269 Line No.: 5 Column: c

Typical account charged: 930.2

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

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	03/09/2018	End of 2017/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
						307	6
							7
						307	8
							9
							10
							11
							12
							13
							14
							15
							16
						307	17
							18
						307	19
							20
							21

NOTES (Continued)

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	03/09/2018	End of 2017/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	9,498,887,556	2,254,799	-95,931,648
3	Gas	2,918,122,275	136,199,723	-34,104,638
4	Nonutility	100,815,309		
5	TOTAL (Enter Total of lines 2 thru 4)	12,517,825,140	138,454,522	-130,036,286
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	12,517,825,140	138,454,522	-130,036,286
10	Classification of TOTAL			
11	Federal Income Tax	9,802,035,265	108,416,286	-101,824,418
12	State Income Tax	2,715,789,875	30,038,236	-28,211,868
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	03/09/2018	End of 2017/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
			3,730,880,846			5,866,193,157	2
			1,610,766,845			1,477,659,791	3
15,349,787	-2,279,469		67,918,362			50,526,203	4
15,349,787	-2,279,469		5,409,566,053			7,394,379,151	5
							6
							7
							8
15,349,787	-2,279,469		5,409,566,053			7,394,379,151	9
							10
12,019,592	-1,784,930		4,235,940,080			5,790,140,411	11
3,330,195	-494,539		1,173,625,973			1,604,238,740	12
							13

NOTES (Continued)

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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

FERC Form 1 Pages 274-275
12/31/17
Detail of Adjustments

	(382,017,455)	Deferred income tax adjustment to account 254
	4,112,898,301	Deferred income tax adjustment to account 254 due to the reduction of federal tax rate
<A>	3,730,880,846	
	($278,249,424)	Deferred income tax adjustment to account 254
	$1,889,017,267	Deferred income tax adjustment to account 254 due to the reduction of federal tax rate
<B>	$1,610,767,843	
<C>	67,918,362	Deferred income tax adjustment to account 254 primarily due to the reduction of federal tax rate

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	50,455,805	779,761	4,883,976
4	Balancing Accounts	334,446,742	-39,327,718	152,671,596
5	Other	7,644,806	-855	5,148,000
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	392,547,353	-38,548,812	162,703,572
10	Gas			
11	Loss on Reacquired Debt	25,242,662	-821,657	2,457,416
12	Balancing Accounts	330,130,399	-36,325,927	23,161,573
13				
14	Other	-2,421,918		-260,486
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	352,951,143	-37,147,584	25,358,503
18	OTHER	-33,569,163		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	711,929,333	-75,696,396	188,062,075
20	Classification of TOTAL			
21	Federal Income Tax	600,013,848	-59,273,774	147,261,291
22	State Income Tax	111,915,485	-16,422,622	40,800,784
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		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
						46,351,590	3
						142,447,428	4
						2,495,951	5
							6
							7
							8
						191,294,969	9
							10
						21,963,589	11
			2,174,576			268,468,323	12
							13
						-2,161,432	14
							15
							16
			2,174,576			288,270,480	17
45,191	-1,007				2,174,579	-31,348,386	18
45,191	-1,007		2,174,576		2,174,579	448,217,063	19
							20
35,387	-789		1,702,793		1,702,796	393,514,962	21
9,804	-218		471,783		471,783	54,702,101	22
							23

NOTES (Continued)

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	(28,901)	182.3	4,113,255	3,834,132	-308,024
2	(amortization: 5 years)					
3	California Solar Initiative	110,751,100	400	58,178,962	13,842,435	66,414,573
4	(amortization: 5 years)					
5	Demand Response Expenditures Balancing Account	49,493,864	400	65,588,633	73,737,513	57,642,744
6	Distribution Resource Plan Demo B/A Curr		400	418,342	526,320	107,978
7	(amortization: <12 months)					
8	DREBA Operations Balancing Account - Current	4,235,014	400	205,765	20,811,388	24,840,637
9	Electric Vehicle Program BA Current		400	5,579,232	3,606,935	-1,972,297
10	(amortization: <12 months)					
11	Electric Price Risk Management - Current	74,663,745	555	194,847,015	147,050,385	26,867,115
12	Electric Price Risk Management - NonCurrent	135,978,524	555	500,077,301	465,599,188	101,500,411
13	Electric Program Investment Charge Balancing Acct	121,450,086	400	470,547,482	522,291,304	173,193,908
14	Engineering Critical Assessment Bal NC	27,770,384	182.3	8,205,070	26,150,894	45,716,208
15	(amortization: >12 months)					
16	FAS 109 Reg Liability		400	3,067,957,565	4,088,791,000	1,020,833,435
17	(amortization: >12 months)					
18	FAS 143 Regulatory Liability - Nuclear	(999,999,999)	Various			-999,999,999
19	FAS 143 Regulatory Liability - Nuclear	(485,864,979)		299,292,087	210,697,135	-574,459,931
20	FAS 143 Regulatory Liability - Fossil	(125,261,507)	Various	6,763,434		-132,024,941
21	FAS 143 Regulatory Liability - Fossil Decomm	188,112,772	228.4	23,507,559	12,028,333	176,633,546
22	FAS 143 Regulatory Liability-Nuclear Decomm	2,606,497,178	128	286,952,872	543,702,919	2,863,247,225
23	FIN 47 Regulatory Liability	(557,604,081)	Various	483,023,020	331,579,629	-709,047,472
24	Gas PPP Surcharge-RDD	(683,039)	400	12,017,043	12,301,917	-398,165
25	(amortization: <12 months)					
26	Gas Price Risk Management - Current	6,544,702	807	19,097,083	12,928,460	376,079
27	GHGRBA - Greenhouse Gas Revenue Subaccount	(35,183,508)	400	220,838,461	345,860,328	89,838,359
28	(amortization: <12 months)					
29	GHGRBA - Low Carbon Fuels Stnd Rev Subaccount	7,862,720	400	22,793,678	33,557,522	18,626,564
30	(amortization: <12 months)					
31	GPBA - Greenhouse Gas Revenue Subaccount	129,985,191	400	4,957	92,849,633	222,829,867
32	(amortization: <12 months)					
33	GPBA - Low Carbon Fuels Stnd Rev Subaccount	1,356,655	400	4,267,597	3,596,940	685,998
34	(amortization: <12 months)					
35	Miscellaneous Electric Reg Liab - Current	193,888,610	449	132,733,663	19,458,531	80,613,478
36	(amortization: <12 months)					
37	Miscellaneous Electric Reg Liab - NonCurrent	49,406,465	549	17,797,596	213,416,652	245,025,521
38	Miscellaneous Gas Reg Liab - NonCurrent	28,851,724	549	11,683,900	1,858,644	19,026,468
39	(amortization: 2 years)					
40	Non Current Reg Liab-CC8 Settlement	49,116,685	108	2,302,726	42,220	46,856,179
41	TOTAL	2,227,787,406		7,350,211,392	8,998,529,484	3,876,105,498

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	03/09/2018	End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (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: 25 Years)					
2	Non-Tariffed Products and Svcs BA-Electric	248,849	182.3	1,763,986	1,836,704	321,567
3	(amortization: < 12 months)					
4	Non-Tariffed Products and Svcs BA-Gas	203,504	182.3	289,388	348,879	262,995
5	(amortization: < 12 months)					
6	On Bill Financing Balancing Electric	39,231,831	930.2	16,831,300	21,653,389	44,053,920
7	On Bill Financing Balancing Gas	8,611,774	930.2	3,744,745	4,674,463	9,541,492
8	PPP (PPPLIBA)-Electric	149,948,594	400	73,586,786	85,398,275	161,760,083
9	(amortization: <12 months)					
10	PPP (PPPLIBA)-Gas	33,092,948	400	52,244,098	76,266,919	57,115,769
11	(amortization: <12 months)					
12	PPP Energy Efficiency-Gas	10,229,431	400	6,840,333	134,162	3,523,260
13	PPP Surcharge Energy Efficiency - Gas	(2,891,187)	400	116,438,894	125,495,163	6,165,082
14	(amortization: <12 months)					
15	PPP Surcharge Low Income - Gas	(8,729,347)	400	76,768,109	76,800,435	-8,697,021
16	(amortization: <12 months)					
17	PPP Surcharge RDD - Current	3,940,387	182.3	11,566,500	11,215,748	3,589,635
18	(amortization: <12 months)					
19	Procurement Energy Efficiency	45,936,663	400	31,399,368	570,748	15,108,043
20	Procurement Energy Efficiency Bal Acct Current	22,235,149	400	438,822,785	537,953,201	121,365,565
21	(amortization: <12 months)					
22	Publ Purp Prog Energy Efficiency Bal Acct Current	5,191,567	400	108,763,172	128,187,385	24,615,780
23	(amortization: <12 months)					
24	Reg Liability Gas Risk MGMT - Noncurrent	4,235,317	807	7,038,782	3,433,449	629,984
25	Regulatory Liability Retirement	194,074,416	520	43,774,251	267,761,550	418,061,715
26	(amortization: indefinite)					
27	Self Generation Program - Electric	147,980,894	400	31,841,885	64,248,528	180,387,537
28	Self Generation Program-Gas	27,952,543	400	6,989,682	14,057,169	35,020,030
29	SW Marketing, Education and Outreach Program BA	4,901,511	400	25,754,163	25,201,821	4,349,169
30	SW Marketing, Education and Outreach Program BA	814,554	400	2,848,560	2,789,738	755,732
31	TAMA - Gas	(59,765,309)	182.3	4,725,006		-64,490,315
32	(amortization: 2 Years)					
33						
34	Miscellanous minor items	19,003,912	Various	369,385,301	350,381,401	12
35						
36						
37						
38						
39						
40						
41	TOTAL	2,227,787,406		7,350,211,392	8,998,529,484	3,876,105,498

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 18 Column: b

The FERC software will not allow the entire beginning balance of FAS 143 Regulatory Liability of ($1,485,864,978) 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:	($485,864,979)
Total	($1,485,864,978)

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 ($1,574,459,929) 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.: 23 Column: c

Offset to account 108 - Accumulated Depreciation, and 230 - ARO - Liability.

Schedule Page: 278.1 Line No.: 34 Column: c

Activity primarily related to Vegetation Management offset 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	03/09/2018	End of 2017/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	5,693,009,418	5,408,907,591
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	6,499,737,292	6,622,244,360
5	Large (or Ind.) (See Instr. 4)	1,603,479,860	1,525,023,120
6	(444) Public Street and Highway Lighting	69,800,620	71,522,984
7	(445) Other Sales to Public Authorities	2,175,010	2,630,081
8	(446) Sales to Railroads and Railways	6,988,161	5,980,830
9	(448) Interdepartmental Sales	44,421,522	44,898,176
10	TOTAL Sales to Ultimate Consumers	13,919,611,883	13,681,207,142
11	(447) Sales for Resale	112,554,619	2,996,529
12	TOTAL Sales of Electricity	14,032,166,502	13,684,203,671
13	(Less) (449.1) Provision for Rate Refunds	169,512,710	107,912,349
14	TOTAL Revenues Net of Prov. for Refunds	13,862,653,792	13,576,291,322
15	Other Operating Revenues		
16	(450) Forfeited Discounts	5,496,959	6,872,964
17	(451) Miscellaneous Service Revenues	9,650,326	7,485,433
18	(453) Sales of Water and Water Power	3,621,831	3,433,187
19	(454) Rent from Electric Property	86,527,942	87,415,601
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-343,369,626	-103,012,106
22	(456.1) Revenues from Transmission of Electricity of Others	2,830,782	6,593,382
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(400) Balancing Accounts	-343,783,254	296,968,335
26	TOTAL Other Operating Revenues	-579,025,040	305,756,796
27	TOTAL Electric Operating Revenues	13,283,628,752	13,882,048,118

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
29,408,850	28,660,730	4,808,753	4,760,209	2
				3
36,881,436	38,213,377	634,978	632,578	4
15,187,122	15,402,877	1,325	1,326	5
327,380	351,762	34,795	34,237	6
12,177	17,131	13	15	7
407,351	372,171	25	25	8
289,607	308,929			9
82,513,923	83,326,977	5,479,889	5,428,390	10
5,661,727	1,740,435			11
88,175,650	85,067,412	5,479,889	5,428,390	12
				13
88,175,650	85,067,412	5,479,889	5,428,390	14

Line 12, column (b) includes $ 0 of unbilled revenues.
Line 12, column (d) includes 0 MWH relating to unbilled revenues

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

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 $315,481,524 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 412,205,699 which was deducted from Line 21 below.

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

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.: 17 Column: c

This consists of :

NSF fees and rent charges to customers' refundable deposits	2,194,254
MLX billings to electric residential customers	3,003,663
Reimbursable third-party labor requested on behalf of customers	1,100,735
MLX billings to electric non-residential customers	1,093,993
Miscellaneous (items under $250,000)	92,789
Total	7,485,433

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

This consists of :

Unbilled revenues	(75,837,834)
Reimbursement to the Utility for costs spent on customer projects	50,772,932

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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.

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

This consists of :

DWR	(412,205,699)
Unbilled revenues	153,376,471
Other electric revenues not classified elsewhere	57,178,986
Reimbursement to the Utility for costs spent on customer projects	50,948,673
Fees for utility energy service contracts	32,731,362
Transition Cost Revenue Account for non-bypassable charges	32,515,881
Reimbursement fees paid to the CPUC based on sales	(27,030,160)
Revenue assigned - base	(19,810,324)
Pass-through franchise fees and uncollectible revenue	19,810,324
Other revenue-damage claim	3,693,297
Fees for customer billing for third party service providers	2,062,886
Recreational Facilities Revenue	1,368,654

Employee transfer fees	1,279,635
MCI rights of way	691,661
Reimbursement to the Utility for costs spent on customer billing	406,394
Miscellaneous (items under $250,000)	(30,147)
Total	(103,012,106)

The DWR revenues of 412,205,699 above 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.

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales:					
2	E1 Individually Metered	19,550,515	4,241,732,501	3,381,744	5,781	0.2170
3	EL1 Residential Care Program S	7,172,962	947,415,056	1,157,500	6,197	0.1321
4	E6 Residential Time-of-Use Servic	504,806	103,248,302	98,773	5,111	0.2045
5	EL6 Residential Care Time-of-U	40,430	5,185,644	6,328	6,389	0.1283
6	E7 Time-of-Use	117	14,374	5	23,400	0.1229
7	EL7 Residential Care Program T		-442			
8	E8 Seasonal Service Option	-4	-123,730			30.9325
9	EL8 Residential Seasonal Care	1	-82			-0.0820
10	ETOUA Residential Time-of-Use Ser	335,617	69,567,550	60,496	5,548	0.2073
11	EL-TOUA Residential Care Time-of-	47,263	5,295,217	7,658	6,172	0.1120
12	ETOUB Residential Time-of-Use Ser	342,112	75,649,381	24,533	13,945	0.2211
13	EL-TOUB Residential Care Time-of-	35,078	4,600,919	3,214	10,914	0.1312
14	ETOUP Residential Time-of-Use Ser	63,025	11,331,505	11,471	5,494	0.1798
15	EA9 Experimental TOU Service for					
16	EB9 Experimental TOU Service for		58			
17	ECLSD		423			
18	EVA Residential TOU Service for P	579,811	103,883,073	36,536	15,870	0.1792
19	EVB Residential TOU Service for P	1,356	191,510	494	2,745	0.1412
20	EM Master-Metered Multi-family Se	224,199	46,344,033	16,538	13,557	0.2067
21	EML Multifamily CARE Program - Ma	27,570	3,572,602	184	149,837	0.1296
22	EMTOU Residential Time of Use Ser	1,610	337,111	146	11,027	0.2094
23	ES Multi-family Service	25,612	4,375,138	288	88,931	0.1708
24	ESL Multifamily CARE Program Serv	28,637	4,404,816	310	92,377	0.1538
25	ESR RV Park and Residential Marin	2,265	442,706	27	83,889	0.1955
26	ESRL RV Park and Residential Mari	8,672	1,365,500	80	108,400	0.1575
27	ET Mobilehome Park Service	15,938	2,666,943	241	66,133	0.1673
28	ETL Low-Income Mobile Home	398,366	60,915,814	2,160	184,429	0.1529
29	MIS-RS	48	35			0.0007
30	SE1 Standby - Individually Metere	61	19,455	3	20,333	0.3189
31	SEM1 Standby - Master-Metered Mul	2,783	516,261	10	278,300	0.1855
32	STOUS INDV Standby - TOU		755	3		
33	UNCLASSIFIED		56,990	11		
34	Total Residential	29,408,850	5,693,009,418	4,808,753	6,116	0.1936
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	82,513,923	14,032,166,502	5,479,889	15,058	0.1701
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	82,513,923	14,032,166,502	5,479,889	15,058	0.1701

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	442 Commercial and Industrial Sal					
2	A1 Small General Service	1,090,858	210,338,643	48,933	22,293	0.1928
3	A1F Small General Service	71,826	16,296,273	17,571	4,088	0.2269
4	A1X Small General Service	5,742,178	1,244,977,368	364,602	15,749	0.2168
5	A15 Small General Service	476	270,932	414	1,150	0.5692
6	A6 Time-of-Use	1,482,373	298,198,798	26,816	55,279	0.2012
7	A10 Medium General	8,746,296	1,582,044,012	43,947	199,019	0.1809
8	E19 500 to 999 Kw Demand	13,838,402	1,985,878,687	27,129	510,096	0.1435
9	E20 1000 Kw Demand or More	13,344,175	1,376,585,925	1,002	13,317,540	0.1032
10	E37 1000 Kw Demand or More	432,908	53,322,667	367	1,179,586	0.1232
11	AG1 Agricultural Power	78,239	23,240,482	4,998	15,654	0.2970
12	AG4 TOU Agricultural Power	992,847	289,931,540	53,860	18,434	0.2920
13	AG5 Large TOU Agricultural Power	3,949,707	712,053,562	26,027	151,754	0.1803
14	AGICE Agricultural Internal Combu	152,503	26,193,277	1,638	93,103	0.1718
15	AGR Split-Wk TOU Agricultural Pow	34,360	9,778,002	2,128	16,147	0.2846
16	AGV Short-Pk TOU Agricultural Pow	29,846	7,608,002	1,437	20,770	0.2549
17	OL1 Outdoor Area Lighting Service	10,133	3,012,002	14,570	695	0.2972
18	SA1 Standby & General Service	66	15,562	6	11,000	0.2358
19	SA6 Standby & Small TOU	5,101	1,368,344	14	364,357	0.2683
20	SA10 Standby & Alt. Rate for Med-	13,714	1,898,478	22	623,364	0.1384
21	SE19 Standby & 500 to 999 Kw	113,297	17,406,511	74	1,531,041	0.1536
22	SE20 Standby & 1000 Kw Demand	1,445,149	162,074,433	103	14,030,573	0.1122
23	SE37 Standby - Med Gen	53,808	6,129,199	2	26,904,000	0.1139
24	STOUP Standby - TOU Primary	12,191	10,621,246	244	49,963	0.8712
25	STOUT Standby - TOU Transformer	427,150	61,643,407	249	1,715,462	0.1443
26	STOUS INDV Standby - TOU	866	2,322,913	149	5,812	2.6823
27	UNCLASSIFIED	88	6,887	1	88,000	0.0783
28						
29						
30						
31	Total Commercial and Industrial	52,068,557	8,103,217,152	636,303	81,830	0.1556
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	82,513,923	14,032,166,502	5,479,889	15,058	0.1701
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	82,513,923	14,032,166,502	5,479,889	15,058	0.1701

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	03/09/2018	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street and Highway Lig					
2	LS1-A Utility-Owned Street & High	16,464	8,107,704	4,435	3,712	0.4925
3	LS1-B Utility-Owned Street & High	28	7,185	7	4,000	0.2566
4	LS1-C Utility-Owned Street & High	5,183	2,808,491	561	9,239	0.5419
5	LS1-D Utility-Owned Street & High	7,433	3,212,352	984	7,554	0.4322
6	LS1-E Utility-Owned Street & High	10,828	8,012,949	1,706	6,347	0.7400
7	LS1-F Utility-Owned Street & High	5,537	2,610,880	1,634	3,389	0.4715
8	LS2-A Customer-Owned Street & Hig	226,130	33,925,055	9,276	24,378	0.1500
9	LS2-C Customer-Owned Street & Hig	3,829	901,063	457	8,379	0.2353
10	LS3 Cust-Owned Street & Highway L	8,554	1,298,432	1,393	6,141	0.1518
11	LS3-F Cust-Owned Street & Highway	4,068	744,261	2,191	1,857	0.1830
12	TC1 Traffic Control Service	38,136	7,898,463	11,566	3,297	0.2071
13	TC1F Traffic Control Service	1,191	273,785	585	2,036	0.2299
14						
15	Total Public Street and Highway	327,381	69,800,620	34,795	9,409	0.2132
16						
17	445 Other Sales to Public Authori					
18	Special Contracts	12,177	2,175,010	13	936,692	0.1786
19	Total Other Sales to Public Aut	12,177	2,175,010	13	936,692	0.1786
20						
21	446 Sales to Railroads and Railwa					
22	Special Contracts	407,351	6,988,161	25	16,294,040	0.0172
23	Total Sales to Railroads and Ra	407,351	6,988,161	25	16,294,040	0.0172
24						
25	448 Interdepartmental Sales	289,607	44,421,522			0.1534
26	Total Interdepartmental Sales	289,607	44,421,522			0.1534
27						
28	Total Sales to					
29	Ultimate Consumers					
30						
31	447 Sales for Resale					
32	Special Contracts		112,554,619			
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	82,513,923	14,032,166,502	5,479,889	15,058	0.1701
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	82,513,923	14,032,166,502	5,479,889	15,058	0.1701

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 14 Column: a

The pilot program is being offered to a select number of residential customers to help determine the best way to structure new rate plans, as a result of a recent decision by the CPUC. The program began June 1, 2016 and ended December 2017.

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	0.05	17.7	17.7
3	Hetch Hetchy	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
882	514	21,870	-10,621	11,763	2
					3
5,660,845		114,339,999	-1,797,143	112,542,856	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
5,661,727	514	114,361,869	-1,807,764	112,554,619	
0	0	0	0	0	
5,661,727	**514**	**114,361,869**	**-1,807,764**	**112,554,619**	

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 2 Column: a

- Sales represent the Grizzly Power Sale.
- Silicon Valley Power was formally the City of Santa Clara.

Electric sales in 2013 include retroactive supplemental and maintenance power sales for 2012 billed to SVP-Grizzly in 2013 due to contract billing methodolgy negotiations between PG&E and SVP that were settled in March 2013 (ER12-1599-000).

Schedule Page: 310 Line No.: 3 Column: a

Represents Supplemental Demand A-1, Supplemental Demand A-2, and energy sales, if applicable.

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	03/09/2018	End of 2017/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	1,413	
5	(501) Fuel	176,832,878	152,252,947
6	(502) Steam Expenses	10,249	108,753
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	651,480	353,868
11	(507) Rents		
12	(509) Allowances	27,272,848	34,794,578
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	204,768,868	187,510,146
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	17,771	
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant	1,669,805	3,241,313
18	(513) Maintenance of Electric Plant	-11,150,358	3,368,157
19	(514) Maintenance of Miscellaneous Steam Plant	4,324,333	9,146,456
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	-5,138,449	15,755,926
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	199,630,419	203,266,072
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	6,147,760	3,243,338
25	(518) Fuel	124,868,867	127,864,758
26	(519) Coolants and Water	30,611,193	26,180,362
27	(520) Steam Expenses	38,190,638	35,905,219
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	1,998,438	1,904,738
31	(524) Miscellaneous Nuclear Power Expenses	164,674,710	190,442,620
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	366,491,606	385,541,035
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,239,200	2,436,114
36	(529) Maintenance of Structures	1,104,975	1,601,877
37	(530) Maintenance of Reactor Plant Equipment	29,240,710	25,149,916
38	(531) Maintenance of Electric Plant	42,948,466	39,946,858
39	(532) Maintenance of Miscellaneous Nuclear Plant	57,119,138	69,409,840
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	133,652,489	138,544,605
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	500,144,095	524,085,640
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,199,949	790,683
45	(536) Water for Power	2,128,801	2,204,783
46	(537) Hydraulic Expenses	1,317,581	1,485,978
47	(538) Electric Expenses	29,079,473	31,172,630
48	(539) Miscellaneous Hydraulic Power Generation Expenses	65,379,284	49,639,261
49	(540) Rents	785,420	728,620
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	100,890,508	86,021,955
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,542,935	2,778,009
54	(542) Maintenance of Structures	5,802,047	4,666,823
55	(543) Maintenance of Reservoirs, Dams, and Waterways	35,462,156	29,729,070
56	(544) Maintenance of Electric Plant	21,197,455	22,231,376
57	(545) Maintenance of Miscellaneous Hydraulic Plant	8,679,202	8,823,703
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	73,683,795	68,228,981
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	174,574,303	154,250,936

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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	186,426	294,482
63	(547) Fuel		
64	(548) Generation Expenses	11,035,728	11,800,149
65	(549) Miscellaneous Other Power Generation Expenses	-3,161,565	61,046,007
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	8,060,589	73,140,638
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	59,192	96,389
70	(552) Maintenance of Structures	2,735,312	3,177,937
71	(553) Maintenance of Generating and Electric Plant	5,487,309	16,386,615
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,924,933	1,564,147
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	11,206,746	21,225,088
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	19,267,335	94,365,726
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	3,852,611,625	4,130,065,916
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	277,460,451	357,421,813
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,130,072,076	4,487,487,729
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,023,688,228	5,463,456,103
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,652,100	1,980,822
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	28,980,843	30,795,325
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	26,125,073	27,257,867
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	10,285,155	10,727,010
93	(562) Station Expenses	6,400,713	5,857,460
94	(563) Overhead Lines Expenses	6,577,810	6,730,256
95	(564) Underground Lines Expenses	1,495,308	1,511,260
96	(565) Transmission of Electricity by Others	13,665,066	15,605,261
97	(566) Miscellaneous Transmission Expenses	83,829,810	87,489,750
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	180,011,878	187,955,011
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	832,264	1,142,072
102	(569) Maintenance of Structures	645,279	702,061
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	21,874,666	22,132,051
108	(571) Maintenance of Overhead Lines	96,349,282	82,198,554
109	(572) Maintenance of Underground Lines	192,100	1,055,835
110	(573) Maintenance of Miscellaneous Transmission Plant	1,070,803	929,615
111	TOTAL Maintenance (Total of lines 101 thru 110)	120,964,394	108,160,188
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	300,976,272	296,115,199

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
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	14,650,908	15,270,198
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	14,650,908	15,270,198
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)	14,650,908	15,270,198
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,382,277	7,084,062
135	(581) Load Dispatching		
136	(582) Station Expenses	2,196,251	1,811,479
137	(583) Overhead Line Expenses	20,503,087	17,401,186
138	(584) Underground Line Expenses	30,005,042	34,532,949
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	1,691,253	2,306,171
141	(587) Customer Installations Expenses	14,004,409	15,676,650
142	(588) Miscellaneous Expenses	37,055,570	364,723,350
143	(589) Rents	78,291	
144	TOTAL Operation (Enter Total of lines 134 thru 143)	109,916,180	443,535,847
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	4,493,803	6,939,456
147	(591) Maintenance of Structures	2,542,906	5,863,236
148	(592) Maintenance of Station Equipment	26,724,342	24,642,816
149	(593) Maintenance of Overhead Lines	528,832,572	402,984,686
150	(594) Maintenance of Underground Lines	41,892,183	35,303,282
151	(595) Maintenance of Line Transformers	2,125,962	2,132,866
152	(596) Maintenance of Street Lighting and Signal Systems	2,056,782	2,940,424
153	(597) Maintenance of Meters	7,058,358	8,342,960
154	(598) Maintenance of Miscellaneous Distribution Plant	680,573	645,145
155	TOTAL Maintenance (Total of lines 146 thru 154)	616,407,481	489,794,871
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	726,323,661	933,330,718
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	12,819,397	6,659,804
160	(902) Meter Reading Expenses	6,183,670	7,203,896
161	(903) Customer Records and Collection Expenses	156,058,369	153,268,507
162	(904) Uncollectible Accounts	42,122,468	39,526,738
163	(905) Miscellaneous Customer Accounts Expenses	-1,226,397	5,647,599
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	215,957,507	212,306,544

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	512,432,586	603,279,583
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	471,252	7,869,456
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	512,903,838	611,149,039
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,194,885	2,273,279
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,194,885	2,273,279
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	304,370,923	358,307,049
182	(921) Office Supplies and Expenses	55,729,129	68,132,813
183	(Less) (922) Administrative Expenses Transferred-Credit	50,102,503	27,399,104
184	(923) Outside Services Employed	162,252,920	205,063,792
185	(924) Property Insurance	14,161,414	15,451,679
186	(925) Injuries and Damages	190,423,721	223,742,232
187	(926) Employee Pensions and Benefits	384,675,276	360,500,184
188	(927) Franchise Requirements	102,108,129	103,106,815
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	121,950	8,647
192	(930.2) Miscellaneous General Expenses	6,306,443	11,392,165
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	1,170,047,402	1,318,306,272
195	Maintenance		
196	(935) Maintenance of General Plant	8,482,612	10,958,561
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	1,178,530,014	1,329,264,833
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	7,974,225,313	8,863,165,913

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 76 Column: b

Of the year end balance, $204,601 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 76 Column: c

Of the year end balance, ($185,288) 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 end of year balance, $0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: b

Of the quarter end balance, $693 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: c

Of the year end balance, $68,549 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: b

Of the quarter end balance, $196,979 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: c

Of the year end balance, $425,264 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: b

Schedule Page: 320 Line No.: 187 Column: c

Of the year end balance, $0 relates to energy storage operation per FERC Order 784.

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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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	0.07658	N/A
4	MONTEREY REGIONAL WATER	LU		0.00000	0.29345	N/A
5	WASTE MANAGEMENT RENEWABLE	LU		0.00000	5.44325	N/A
6	BIOMASS-BURNEY FOREST PRODUCTS	LU		24.00000	27.60480	N/A
7	DG FAIRHAVEN POWER, LLC	LU		16.00000	15.17040	N/A
8	HL POWER	LU		20.00000	2.12112	N/A
9	HUMBOLDT REDWOOD COMPANY	LU		0.00000	16.59440	N/A
10	RIO BRAVO FRESNO	LU		23.50000	24.81122	N/A
11	RIO BRAVO ROCKLIN	LU		22.00000	24.65267	N/A
12	WHEELABRATOR SHASTA	LU		49.68000	50.43117	N/A
13	HYDRO-CHARCOAL RAVINE	LU		0.00000	0.00018	N/A
14	ERIC AND DEBBIE WATTENBURG	LU		0.00000	0.09566	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	FIVE BEARS HYDROELECTRIC	LU		0.00000	0.94158	N/A
2	HUMBOLDT BAY MWD	LU		0.00000	1.33720	N/A
3	HYDRO SIERRA DEADWOOD CREEK	LU		0.00000	0.67075	N/A
4	HYPOWER INC.	LU		0.00000	10.11600	N/A
5	JAMES B. PETER	LU		0.00000	0.01700	N/A
6	JAMES CRANE HYDRO	LU		0.00000	0.00076	N/A
7	JOHN NEERHOUT JR.	LU		0.00000	0.01397	N/A
8	LOFTON RANCH	LU		0.00000	0.13391	N/A
9	MALACHA HYDRO L.P.	LU		0.00000	21.52100	N/A
10	NELSON CREEK POWER	LU		0.00000	0.65370	N/A
11	NID BOWMAN HYDROELECTRIC	LU		0.00000	2.79825	N/A
12	OLCESE WATER DISTRICT	LU		0.00000	8.52392	N/A
13	OLSEN POWER PARTNERS	LU		0.00000	3.30242	N/A
14	ORANGE COVE IRRIGATION DISTRICT	LU		0.00000	0.37900	N/A
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	ROCK CREEK WATER DISTRICT	LU		0.00000	0.16875	N/A
2	SANTA CLARA VALLEY WATER DIST.	LU		0.00000	0.43991	N/A
3	SCHAADS HYDRO	LU		0.00000	0.16625	N/A
4	SNOW MOUNTAIN BURNEY CREEK	LU		0.00000	1.95283	N/A
5	SNOW MOUNTAIN COVE	LU		0.00000	3.40707	N/A
6	SNOW MT. PONDEROSA BAILEY CREEK	LU		0.00000	0.94425	N/A
7	STS HYDROPOWER LTD KANAKA	LU		0.00000	0.76591	N/A
8	SUTTER'S MILL SHAMROCK	LU		0.00000	0.10280	N/A
9	SWISS AMERICA	LU		0.00000	0.02338	N/A
10	TOM BENNINGHOVEN	LU		0.00000	0.01032	N/A
11	TRI-DAM PWR AUTHORITY	LU		15.00000	15.42267	N/A
12	KINGS RIVER HYDRO	LU		0.00000	0.29516	N/A
13	HYDRO PARTNERS CLOVER CREEK	IU		0.00000	0.80336	N/A
14	EL DORADO HYDRO LLC (MONTGOMERY	LU		0.00000	2.80252	N/A
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	MEGA RENEWABLES (ROARING CRK)	LU		0.00000	0.91471	N/A
2	MEGA RENEWABLES (HATCHET CRK)	LU		0.00000	5.47800	N/A
3	MEGA RENEWABLES (BIDWELL DITCH)	LU		0.00000	1.75150	N/A
4	MEGA RENEWABLES (SILVER SPRINGS)	LU		0.00000	0.37725	N/A
5	EIF HAYPRESS LLC (LWR)	LU		0.00000	3.49733	N/A
6	EIF HAYPRESS LLC (MDL)	LU		0.00000	3.85400	N/A
7	NEVADA IRRIGATION DISTRICT/BOWMAN	LU		0.00000	2.79825	N/A
8	GANSNER HYDRO	LU		0.00000	0.09566	N/A
9	INDIAN VALLEY HYDRO	IU		0.00000	1.40282	N/A
10	SOLAR-VILLA SORRISO SOLAR	LU		0.00000	0.00053	N/A
11	WIND-DONALD R. CHENOWETH	LU		0.00000	0.00086	N/A
12	EDF RENEWABLE WINDFARM V, INC (10	LU		0.00000	8.38038	N/A
13	EDF RENEWABLE WINDFARM V, INC (70	LU		0.00000	0.00000	N/A
14	EDF RENEWABLE WINDFARM V, INC (70	LU		0.00000	3.34486	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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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)	Average Monthly CP Demand (f)
1	INTERNATIONAL TURBINE RESEARCH	LU		0.00000	13.49450	N/A
2	EDF RENEWABLE WINDFARM V, INC (10	LU		0.00000	8.38038	N/A
3	EDF RENEWABLE INC 70 MW C	LU		0.00000	3.34486	N/A
4	EDF RENEWABLE INC 10 MW	LU		0.00000	8.38038	N/A
5	THERMAL:			0.00000	0.00000	
6	COGEN-1080 CHESTNUT CORP.	LU		0.00000	0.00706	N/A
7	AIRPORT CLUB	LU		0.00000	0.00247	N/A
8	ARDEN WOOD BENEVOLENT ASSOC.	LU		0.00000	0.00124	N/A
9	CALPINE KING CITY COGEN	LU		111.00000	121.00200	N/A
10	CHEVRON RICHMOND REFINERY	LU		0.00000	3.81467	N/A
11	CROCKETT COGEN	LU		240.00000	220.09689	N/A
12	ECO SERVICES OPERATIONS LLC	LU		0.00000	0.46075	N/A
13	FRESNO COGENERATION PARTNERS, LP	LU		33.00000	35.37333	N/A
14	FRITO-LAY COGEN	LU		0.00000	0.59486	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	03/09/2018	End of 2017/Q4

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(Including power exchanges)

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1	GREATER VALLEJO RECREATION DIST.	LU		0.00000	0.00599	N/A
2	GREENLEAF UNIT 2	LU		49.20000	48.47025	N/A
3	HAYWARD AREA RECREATION AND PARK	LU		0.00000	0.04591	N/A
4	NIHONMACHI TERRACE	LU		0.00000	0.00693	N/A
5	ORINDA SENIOR VILLAGE	LU		0.00000	0.00085	N/A
6	PE BERKELEY INC	LU		22.47000	0.00000	N/A
7	PHILLIPS 66	LU		0.00000	6.46950	N/A
8	SANGER POWER LLC	LU		38.00000	41.81560	N/A
9	SATELLITE SENIOR HOMES	LU		0.00000	0.00441	N/A
10	SRI INTERNATIONAL	LU		0.00000	1.76825	N/A
11	YUBA CITY COGEN	LU		46.00000	43.04239	N/A
12	PHILLIPS 66	LU		0.00000	6.46950	N/A
13	COUNTY OF SANTA CRUZ (WATER ST.	LU		0.00000	0.00000	N/A
14	GREENLEAF UNIT 1	LU		49.20000	44.59418	N/A
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1	PE KES KINGSBURG LLC	LU		34.50000	27.91060	N/A
2	BERKELEY COGENERATION	LU		22.47000	9.85880	N/A
3	EOR-AERA ENERGY LLC COALINGA	LU		0.00000	2.58919	N/A
4	AERA ENERGY SOUTH BELRIDGE	LU		0.00000	1.98169	N/A
5	BERRY PETROLEUM CO - TANNEHILL	LU		0.00000	12.20752	N/A
6	FREEPORT MCMORAN DOME	LU		0.00000	2.06150	N/A
7	WESTERN POWER & STEAM INC	LU		17.75000	18.42682	N/A
8	SARGENT CANYON COGENERATION	LU		33.50000	3.23800	N/A
9	SALINAS RIVER COGEN CO	LU		34.70000	3.22400	N/A
10	CHEVRON USA (TAFT/CADET)	LU		0.00000	2.63525	N/A
11	CHEVRON USA (CYMRIC)	LU		0.00000	5.64200	N/A
12	CHEVRON USA (COALINGA)	LU		0.00000	2.68700	N/A
13	MIDSET COGEN CO.	LU		34.70000	3.19425	N/A
14	COALINGA COGENERATION COMPANY	LU		37.70000	3.53100	N/A
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1	CHEVRON USA (EASTRIDGE)	LU		0.00000	14.68800	N/A
2	AERA ENERGY LLC. (COALINGA)	LU		0.00000	2.58919	N/A
3	CHEVRON MCKITTRICK FHP	LU		0.00000	3.82300	N/A
4	SENTINEL PEAK RESOURCES	LU		0.00000	2.06150	N/A
5	CHEVRON USA (SE KERN RIVER)	LU		0.00000	7.20725	N/A
6						
7						
8	BILATERALS:			0.00000	0.00000	
9	2041 ALVARES PRISTINE SUN			0.00000	0.00000	
10	2056 JARDINE PRISTINE SUN LLC			0.00000	0.00000	
11	2059 SCHERZ			0.00000	0.00000	
12	2065 ROGERS PRISTINE SUN FUND 5 LLC			0.00000	0.00000	
13	2081 TERZIAN			0.00000	0.00000	
14	2094 BUZZELLE PRISTINE SUN LLC			0.00000	0.00000	
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1	2096 COTTON PRISTINE SUN LLC			0.00000	0.00000	
2	2097 HELTON PRISTINE SUN, LLC			0.00000	0.00000	
3	2102 CHRISTENSEN PRISTINE SUN			0.00000	0.00000	
4	2103 HILL PRISTINE SUN LLC			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 LLC			0.00000	0.00000	
9	2154 FOOTE (Oroville Solar)			0.00000	0.00000	
10	2158 STROING PRISTINE SUN FUND 5 LLC			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	2192 RAMIREZ PRISTINE SUN 6			0.00000	0.00000	
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1	3 Phases Renewable Inc.			0.00000	0.00000	
2	3 PHASES RENEWABLES INC			0.00000	0.00000	
3	ABEC BIDART OLD RIVER			0.00000	0.00000	
4	ABEC BIDART-STOCKDALE LLC			0.00000	0.00000	
5	AGUA CALIENTE SOLAR, LLC			0.00000	0.00000	
6	ALAMO SOLAR			0.00000	0.00000	
7	ALGONQUIN SANGER POWER LLC			0.00000	0.00000	
8	ALGONQUIN SKIC 20 SOLAR, LLC			0.00000	0.00000	
9	ALPAUGH 50, LLC			0.00000	0.00000	
10	ALPAUGH NORTH, LLC			0.00000	0.00000	
11	ANAHAU PWR - BU			0.00000	0.00000	
12	ANGELS POWERHOUSE			0.00000	0.00000	
13	APEX 646-460			0.00000	0.00000	
14	ARBUCKLE MOUNTAIN HYDRO			0.00000	0.00000	
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1	ARLINGTON WIND POWER PROJECT			0.00000	0.00000	
2	ASPIRATION SOLAR G			0.00000	0.00000	
3	ATWELL ISLAND			0.00000	0.00000	
4	AV SOLAR RANCH ONE			0.00000	0.00000	
5	Avenal Solar Project A			0.00000	0.00000	
6	Avenal Solar Project B			0.00000	0.00000	
7	BADGER CREEK LIMITED			0.00000	0.00000	
8	BAKER CREEK HYDROELECTRIC			0.00000	0.00000	
9	BAKERSFIELD 111, LLC			0.00000	0.00000	
10	BEAR CREEK SOLAR LLC			0.00000	0.00000	
11	BEAR MOUNTAIN LIMITED			0.00000	0.00000	
12	BIG CREEK WATER WORKS, LTD.			0.00000	0.00000	
13	BLACKSPRING RIDGE 1A			0.00000	0.00000	
14	BLACKSPRING RIDGE 1B			0.00000	0.00000	
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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	BLAKE'S LANDING FARMS, INC			0.00000	0.00000	
2	BONNEVILLE POWER ADMINSTRATION			0.00000	0.00000	
3	BP Energy Company			0.00000	0.00000	
4	BPA TRANSMISSION			0.00000	0.00000	
5	BROWNS VALLEY IRRIGATION DISTRICT			0.00000	0.00000	
6	BUCKEYE HYDROELECTRIC PROJECT			0.00000	0.00000	
7	BUENA VISTA ENERGY, LLC			0.00000	0.00000	
8	CALAVERAS PUBLIC UTILITY DISTRICT #1			0.00000	0.00000	
9	CALAVERAS PUBLIC UTILITY DISTRICT #2			0.00000	0.00000	
10	CALAVERAS PUBLIC UTILITY DISTRICT #3			0.00000	0.00000	
11	CALPINE ENERGY - AGNEWS, INC			0.00000	0.00000	
12	Calpine Energy - WSPP			0.00000	0.00000	
13	CALPINE ENERGY EEI			0.00000	0.00000	
14	Calpine Energy Services, LP			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CALPINE GEYSERS (200/425 MW)			0.00000	0.00000	
2	CALPINE LOS ESTEROS UPGRADE			0.00000	0.00000	
3	CALPINE PEAKERS			0.00000	0.00000	
4	CALPINE RUSSELL CITY - COD JUNE 2010			0.00000	0.00000	
5	CALRENEW-1 LLC			0.00000	0.00000	
6	CAMS-DOUBLE C LIMITED			0.00000	0.00000	
7	CAMS-HIGH SIERRA LIMITED			0.00000	0.00000	
8	CAMS-KERN FRONT LIMITED			0.00000	0.00000	
9	CASTELANELLI BROS BIOGAS			0.00000	0.00000	
10	CASTOR SOLAR PROJECT			0.00000	0.00000	
11	CE OF MONTANA			0.00000	0.00000	
12	CED Corcoran solar 3 LLC			0.00000	0.00000	
13	CED WHITE RIVER SOLAR 2, LLC			0.00000	0.00000	
14	CED WHITE RIVER SOLAR, 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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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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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	CEDAR FLAT (Shamrock Utilities)			0.00000	0.00000	
2	CHALK CLIFF LIMITED			0.00000	0.00000	
3	CHALK CLIFF LIMITED (2013 CGO FRO-2)			0.00000	0.00000	
4	CHALK CLIFF LIMITED (2013 CHP RFO-2)			0.00000	0.00000	
5	CID SOLAR, LLC			0.00000	0.00000	
6	City of Santa Clara SVP Muni			0.00000	0.00000	
7	CLOVER FLAT LFG			0.00000	0.00000	
8	CLOVER LEAF (Shamrock Utilities)			0.00000	0.00000	
9	CLOVERDALE SOLAR 1, LLC			0.00000	0.00000	
10	COLUMBIA SOLAR ENERGY, LLC			0.00000	0.00000	
11	Commercial Energy of Montana			0.00000	0.00000	
12	COPPER MOUNTAIN 10			0.00000	0.00000	
13	COPPER MOUNTAIN SOLAR 2 (SEMPRA)			0.00000	0.00000	
14	COPPER MOUNTAIN SOLAR 48			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CORAM BRODIE WIND			0.00000	0.00000	
2	CORCORAN SOLAR			0.00000	0.00000	
3	DESERT CENTER SOLAR FARM			0.00000	0.00000	
4	DIGGER CREEK HYDRO			0.00000	0.00000	
5	Direct Energy Business Marketing, LLC			0.00000	0.00000	
6	DTE POTRERO HILL ENERGY PRODCERS			0.00000	0.00000	
7	DTE STOCKTON			0.00000	0.00000	
8	DTE SUNSHINE GAS LANDFILL			0.00000	0.00000	
9	DTE WOODLAND BIOMASS			0.00000	0.00000	
10	DYNEGY EEI			0.00000	0.00000	
11	DYNEGY MOSS LANDING - BU			0.00000	0.00000	
12	ECOS ENERGY LLC KETTLEMAN SOLAR			0.00000	0.00000	
13	EDF TRADING - BU			0.00000	0.00000	
14	EDF Trading EEI			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EDF Trading North America, LLC			0.00000	0.00000	
2	EIF PANOCHE (FIREBAUGH)			0.00000	0.00000	
3	EL DORADO IRRIGATION DISTRICT			0.00000	0.00000	
4	ENERPARC CA1, LLC			0.00000	0.00000	
5	Eqqus Energy Group			0.00000	0.00000	
6	ETIWANDA POWER PLANT			0.00000	0.00000	
7	EURUS (AVENAL PARK, LLC)			0.00000	0.00000	
8	EURUS (SAND DRAG, LLC)			0.00000	0.00000	
9	EURUS (SUN CITY PROJECT, LLC)			0.00000	0.00000	
10	Exelon			0.00000	0.00000	
11	Exelon Generation Company, LLC			0.00000	0.00000	
12	EXELON GENERATION WSPP			0.00000	0.00000	
13	EXELON REC SALE 2016			0.00000	0.00000	
14	FALL RIVER MILLS A (ACHOMAWI)			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	FALL RIVER MILLS B (AHJUMAWI)			0.00000	0.00000	
2	FCM Macquarie			0.00000	0.00000	
3	FPL Energy Power Marketing Inc.			0.00000	0.00000	
4	FRESH AIR ENERGY IV SONORA 1			0.00000	0.00000	
5	FRESNO SOLAR SOUTH			0.00000	0.00000	
6	FRESNO SOLAR WEST			0.00000	0.00000	
7	GAS TRANSPORT ASSOC WITH PANOCHE			0.00000	0.00000	
8	GAS TRANSPORT ASSOC. WITH MARSH			0.00000	0.00000	
9	GENESIS SOLAR ENERGY PROJECT			0.00000	0.00000	
10	GENESIS SOLAR, LLC			0.00000	0.00000	
11	GENON- PITTS 5,6,7 (2011-2015)			0.00000	0.00000	
12	GEYSERS 50/250/425 MW			0.00000	0.00000	
13	GLOBAL AMPERSAND, CHOWCHILLA			0.00000	0.00000	
14	GLOBAL AMPERSAND, EL NIDO			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	GOOSE VALLEY FARMING, LLC			0.00000	0.00000	
2	GOOSE VALLEY HYDRO			0.00000	0.00000	
3	GREEN LIGHT ENERGY SIRUIS SOLAR			0.00000	0.00000	
4	GREEN LIGHT PEACOCK SOLAR PROJ			0.00000	0.00000	
5	GREEN LIGHT SIRIUS SOLAR			0.00000	0.00000	
6	GWF HANFORD 2013-2022			0.00000	0.00000	
7	GWF HENRIETTA 2013-2022			0.00000	0.00000	
8	GWF TRACY REPOWERING PPA			0.00000	0.00000	
9	HALKIRK I WIND PROJECT			0.00000	0.00000	
10	HATCHET RIDGE WIND LLC			0.00000	0.00000	
11	HENRIETTA SOLAR			0.00000	0.00000	
12	HIGH PLAINS RANCH II			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	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			0.00000	0.00000	
5	IMMODO LEMOORE			0.00000	0.00000	
6	IVANPAH UNIT 1			0.00000	0.00000	
7	IVANPAH UNIT 3			0.00000	0.00000	
8	JACKSON VALLEY IRRIGATION DIST			0.00000	0.00000	
9	JR SIMPLOT			0.00000	0.00000	
10	KEKAWAKA CREEK (STS)			0.00000	0.00000	
11	KEKAWAKA CREEK HYDRO RAM 4			0.00000	0.00000	
12	KENT SOUTH - PV 2			0.00000	0.00000	
13	KERN RIVER COGEN (KRCC)			0.00000	0.00000	
14	KINGSBURG 1 - 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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	KINGSBURG 2 - TULARE PV 11 LLC			0.00000	0.00000	
2	KINGSBURG 3 - TULARE PV 11 LLC			0.00000	0.00000	
3	KLONDIKE WIND IIIA POWER			0.00000	0.00000	
4	LA JOYA DEL SOL 1			0.00000	0.00000	
5	LASSEN STATION			0.00000	0.00000	
6	LEMOORE PV 1, LLC			0.00000	0.00000	
7	LIVE OAK LIMITED			0.00000	0.00000	
8	LOST CREEK 1			0.00000	0.00000	
9	LOST CREEK 2			0.00000	0.00000	
10	MACQUARIE FUTURES FCM-BU			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 1923			0.00000	0.00000	
14	MADERA CHOWCHILLA SITE 980			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MAMMOTH G1 (ORMAT) - RAM 2			0.00000	0.00000	
2	MAMMOTH G3 (M3 ORMAT) - RAM 1			0.00000	0.00000	
3	MARIN CLEAN ENERGY EEI			0.00000	0.00000	
4	MARIPOSA ENERGY, LLC			0.00000	0.00000	
5	MARSH LANDING			0.00000	0.00000	
6	MARTINEZ COGEN LP (TESORO)			0.00000	0.00000	
7	MATTHEWS DAM HYDRO			0.00000	0.00000	
8	MCFADDEN HYDROELECTRIC FACILITY			0.00000	0.00000	
9	MCKITTRICK LIMITED			0.00000	0.00000	
10	MERCED IRRIGATION DISTRICT			0.00000	0.00000	
11	MERCED SOLAR ECOS ENERGY			0.00000	0.00000	
12	MESQUITE SOLAR			0.00000	0.00000	
13	MIDWAY SUNSET COGENERATION			0.00000	0.00000	
14	MILL SULPHUR CREEK 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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	MISSION SOLAR ECOS ENERGY			0.00000	0.00000	
2	MOJAVE SOLAR			0.00000	0.00000	
3	MORELOS SOLAR LLC - RAM 3			0.00000	0.00000	
4	Morgan Stanley			0.00000	0.00000	
5	MORGAN STANLEY CAPITAL GROUP EEI			0.00000	0.00000	
6	MT. POSO (RED HAWK)			0.00000	0.00000	
7	NEVADA IRRIGATION DISTRICT NORTH			0.00000	0.00000	
8	NEVADA IRRIGATION DISTRICT SCOTTS			0.00000	0.00000	
9	NEVADA IRRIGATION DISTRICT SOUTH			0.00000	0.00000	
10	NEXTERA DIABLO WINDS			0.00000	0.00000	
11	NEXTERA MONTEZUMA WIND			0.00000	0.00000	
12	NEXTERA MONTEZUMA WIND II			0.00000	0.00000	
13	NICKEL 1 (NLH1 SOLAR, LLC)			0.00000	0.00000	
14	NID NORTH COMBIE FIT			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NID-CHICAGO PARK			0.00000	0.00000	
2	NID-DUTCH FLATS, ROLLINS, BOWMAN			0.00000	0.00000	
3	NORTH SKY RIVER ENERGY CENTER			0.00000	0.00000	
4	NORTH STAR SOLAR			0.00000	0.00000	
5	NRG ALPINE SOLAR			0.00000	0.00000	
6	NRG POWER MARKETING LLC			0.00000	0.00000	
7	NRG SOLAR KANSAS SOUTH			0.00000	0.00000	
8	OAKLEY EXECUTIVE LLC			0.00000	0.00000	
9	OAKLEY EXECUTIVE RV AND BOAT			0.00000	0.00000	
10	OLD RIVER ONE LLC - RAM 3			0.00000	0.00000	
11	ORION SOLAR I, LLC			0.00000	0.00000	
12	OROVILLE COGEN			0.00000	0.00000	
13	ORTIGALITA POWER COMPANY LLC			0.00000	0.00000	
14	PACIFICORP TSA			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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	PCWA LINCOLN HYDRO			0.00000	0.00000	
2	PEACOCK SOLAR PROJ - GREEN LIGHT			0.00000	0.00000	
3	PEACOCK SOLAR PROJECT			0.00000	0.00000	
4	PENINSULA 2017 REC SALE			0.00000	0.00000	
5	PENINSULA CLEAN ENERGY			0.00000	0.00000	
6	PENINSULA CLEAN ENERGY AUTHORITY			0.00000	0.00000	
7	PENINSULA CLEAN ENERGY EEI			0.00000	0.00000	
8	PLACER COUNTY WATER AGENCY			0.00000	0.00000	
9	PLACER COUNTY WATER AGENCY			0.00000	0.00000	
10	PORTAL RIDGE SOLAR C PROJECT			0.00000	0.00000	
11	POTRERO HILLS ENERGY PRODUCERS,			0.00000	0.00000	
12	PRISTINE SUN SCHERZ			0.00000	0.00000	
13	PRISTINE SUN SMOTHERMAN			0.00000	0.00000	
14	PRISTINE SUN TERZIAN			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PUTAH CREEK SOLAR FARMS			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 WATER COMPANY-COX AVE			0.00000	0.00000	
7	SAN LUIS BYPASS			0.00000	0.00000	
8	SANTA MARIA II LFG POWER PLANT			0.00000	0.00000	
9	SDG&E CO - BU			0.00000	0.00000	
10	SEMPRA MESQUITE SOLAR			0.00000	0.00000	
11	SHAFTER SOLAR LLC			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	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 COMPANY TSA			0.00000	0.00000	
10	SILVER SPRINGS			0.00000	0.00000	
11	SO CAL EDISON EEI AGREEMENT			0.00000	0.00000	
12	SOLAR PARTNERS II (IVANPAH UNIT 1)			0.00000	0.00000	
13	SOLAR PARTNERS VIII (IVANPAH UNIT 3)			0.00000	0.00000	
14	SONOMA CLEAN POWER AUTHORITY			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
2	SOUTH SUTTER WATER DISTRICT			0.00000	0.00000	
3	SR SOLIS ORO - PROJECT A			0.00000	0.00000	
4	SR SOLIS ORO - PROJECT B			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	SUNSHINE GAS LANDFILL			0.00000	0.00000	
12	SUTTERS MILL HYDROELECTRIC PLANT			0.00000	0.00000	
13	TESORO REFINING & MARKETING LLC			0.00000	0.00000	
14	THE ENERGY AUTHORITY EEI			0.00000	0.00000	
	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) 03/09/2018	Year/Period of Report End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	THREE FORKS			0.00000	0.00000	
2	TOPAZ SOLAR FARM			0.00000	0.00000	
3	TORO SLO LANDFILL			0.00000	0.00000	
4	TRANSALTA ENREGY MARKETING US			0.00000	0.00000	
5	TUNNEL HILL HYDRO			0.00000	0.00000	
6	TUNNEL HILL HYDROELECTRIC PROJECT			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	VECINO VINEYARDS LLC			0.00000	0.00000	
12	VINTNER SOLAR PROJECT			0.00000	0.00000	
13	WADHAM ENERGY LTD. PART.			0.00000	0.00000	
14	WATER WHEEL RANCH			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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	WECC WREGIS Fees			0.00000	0.00000	
2	WEST ANTELOPE - RAM 1			0.00000	0.00000	
3	WESTERN ANTELOPE BLUE SKY RANCH			0.00000	0.00000	
4	WESTERN ELECTRICITY COORDINATING			0.00000	0.00000	
5	WESTLANDS SOLAR FARMS LLC			0.00000	0.00000	
6	WESTSIDE SOLAR			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 II (CALWIND) - RAM 2			0.00000	0.00000	
11	WOLFSEN BYPASS (AMERICAN ENERGY)			0.00000	0.00000	
12	WOLFSEN BYPASS (CCID)			0.00000	0.00000	
13	WOLFSEN BYPASS FIT			0.00000	0.00000	
14	WOODLAND BIOMASS			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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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)	Average Monthly CP Demand (f)
1	WOODMERE SOLAR FARM			0.00000	0.00000	
2	WOODMERE SOLAR RAM 4			0.00000	0.00000	
3	YCWA MINI HYDRO			0.00000	0.00000	
4	YOLO COUNTY GRASSLAND #3			0.00000	0.00000	
5	YOLO COUNTY GRASSLAND #4			0.00000	0.00000	
6	ZERO WASTE ENERGY DEVELOPMENT			0.00000	0.00000	
7						
8	Pipeline charges			0.00000	0.00000	
9	Core gas supply			0.00000	0.00000	
10	GTN LLC			0.00000	0.00000	
11	RUBY PIPELINE			0.00000	0.00000	
12	WILLIAMS FIELD SERVICES -			0.00000	0.00000	
13	SOUTHERN CA GAS - BU			0.00000	0.00000	
14						
	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	03/09/2018	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Other charges			0.00000	0.00000	
2	Irrigation districts			0.00000	0.00000	
3	Liberty Utilities			0.00000	0.00000	
4	ISO charges for storage cost			0.00000	0.00000	
5	ISO charges (net of storage cost but			0.00000	0.00000	
6	Gas purchases, storage cost & forex			0.00000	0.00000	
7	CARB fees			0.00000	0.00000	
8	Consultancy fees			0.00000	0.00000	
9	Gas Hedges & brokers fees			0.00000	0.00000	
10	RECS from customers			0.00000	0.00000	
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
26			79	793		872	3
-435			1,024	7,951		8,975	4
32,013			160,578	1,231,223		1,391,801	5
129,967			1,746,535	7,209,856		8,956,391	6
666			42,047	27,180		69,227	7
5			-2,886,801	193		-2,886,608	8
22,469			66,060	891,627		957,687	9
124,579			1,528,348	4,976,969		6,505,317	10
105,285			434,230	-1,102,490		-668,260	11
376,635			6,759,280	16,358,939		23,118,219	12
1			5	35		40	13
10			20	578		598	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report End of 2017/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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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)	
3,808			61,550	152,503		214,053	1
4,027			10,995	120,285		131,280	2
3,048			26,071	101,159		127,230	3
62,550			766,191	1,979,596		2,745,787	4
124			206	3,366		3,572	5
7			18	218		236	6
143			302	4,872		5,174	7
825			5,149	23,861		29,010	8
94,345			2,248,782	4,074,606		6,323,388	9
2,888			47,752	112,232		159,984	10
1,984			13,976	83,649		97,625	11
46,996			351,787	1,836,929		2,188,716	12
18,023			222,052	555,406		777,458	13
2,773			72,662	88,017		160,679	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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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)	
680			3,382	23,839		27,221	1
1,946				65,233		65,233	2
779			3,736	24,780		28,516	3
10,663			136,117	451,534		587,651	4
19,900			261,133	874,371		1,135,504	5
5,265			87,842	199,558		287,400	6
4,090			50,981	175,365		226,346	7
684			3,797	28,029		31,826	8
156			1,245	4,926		6,171	9
76			263	2,687		2,950	10
26				1,026		1,026	11
1,321			25,722	51,157		76,879	12
5,455			30,917	154,707		185,624	13
11,830			72,367	426,373		498,740	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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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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.
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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)	
-256			-1,849	-7,436		-9,285	1
2,856			20,960	101,462		122,422	2
1,767			15,101	60,018		75,119	3
1,694			31,535	48,919		80,454	4
11,636			228,828	451,917		680,745	5
11,311			228,993	441,659		670,652	6
-1			-7,755	-43,275		-51,030	7
246			1,017	9,429		10,446	8
3,600			55,688	119,467		175,155	9
5			20	171		191	10
9			30	292		322	11
5,529			70,222	205,284		275,506	12
1,144			1,361	41,924		43,285	13
1,141			8,390	48,863		57,253	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

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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)	
21,059			550,010	836,247		1,386,257	1
-1,024			-9,527	-35,809		-45,336	2
4,924			139,860	192,385		332,245	3
12,250			221,420	455,238		676,658	4
							5
63			199	2,118		2,317	6
23			65	740		805	7
8			27	310		337	8
387,382			24,948,946	12,523,019		37,471,965	9
-1,858			-3,330	105,127		101,797	10
1,385,007			53,063,949	47,317,924		100,381,873	11
208			691	7,561		8,252	12
11,649			7,292,414	692,020		7,984,434	13
608			3,722	22,280		26,002	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
61			173	2,017		2,190	1
236,702			10,016,343	6,883,332		16,899,675	2
457			1,350	15,206		16,556	3
45			120	1,527		1,647	4
8			24	257		281	5
106,988			2,324,730	3,708,085		6,032,815	6
13,109			45,139	465,737		510,876	7
29,738			2,294,438	903,466		3,197,904	8
1				29		29	9
6,879			14,335	235,186		249,521	10
28,280			10,621,512	1,196,475		11,817,987	11
498			636	23,331		23,967	12
				3		3	13
15,116			9,167,084	1,274,127		10,441,211	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
14,449			8,898,675	749,455		9,648,130	1
6,524			1,944	212,582		214,526	2
9,281			48,083	293,265		341,348	3
6,114			32,205	173,820		206,025	4
80,222			586,214	2,570,699		3,156,913	5
11,082			68,014	351,591		419,605	6
150,779			1,442,724	4,874,100		6,316,824	7
99			1,308	285,744		287,052	8
-588			-43	261,760		261,717	9
5,862			37,062	191,115		228,177	10
24,945			144,272	817,689		961,961	11
8,605			84,510	274,767		359,277	12
-4,518			-293,339	58,365		-234,974	13
381			969	300,976		301,945	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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22,532			123,482	737,411		860,893	1
93			558	9,705		10,263	2
20,681				1,290,058		1,290,058	3
1,179			2,957	43,944		46,901	4
1,659			17,196	50,097		67,293	5
							6
							7
							8
622				91,472		91,472	9
2,734				393,529		393,529	10
121				13,374		13,374	11
566				82,037		82,037	12
330				36,146		36,146	13
1,202				178,029		178,029	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
2,317				345,329		345,329	1
3,647				550,716		550,716	2
2,370				348,678		348,678	3
599				89,912		89,912	4
864				47,994		47,994	5
540				75,421		75,421	6
582				86,558		86,558	7
2,719				416,361		416,361	8
275				37,451		37,451	9
981				143,988		143,988	10
49				5,412		5,412	11
3,594				308,093		308,093	12
559				82,711		82,711	13
547				68,934		68,934	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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)	
-86,279				-1,423,604		-1,423,604	1
			-207,400			-207,400	2
12,089				1,759,338		1,759,338	3
785				142,826	-36,412	106,414	4
702,687				122,933,289		122,933,289	5
50,972				4,375,329		4,375,329	6
			6,091,580			6,091,580	7
48,105				4,206,508		4,206,508	8
126,259				20,459,251		20,459,251	9
49,645				7,692,266		7,692,266	10
			2,830,500			2,830,500	11
2,329				91,020		91,020	12
1,763				225,654		225,654	13
263				20,581		20,581	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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

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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)	
183,805				19,018,636		19,018,636	1
5,798				188,151		188,151	2
38,002				6,138,291		6,138,291	3
603,932				92,947,863		92,947,863	4
17,669				804,260		804,260	5
17,550				805,020		805,020	6
16,119			3,903,454	304,249		4,207,703	7
4,650				357,177		357,177	8
3,319				436,508		436,508	9
3,329				502,847		502,847	10
33,822			3,887,177	504,843		4,392,020	11
10,455				952,597		952,597	12
				17,529,729		17,529,729	13
				18,697,719		18,697,719	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
176				13,680		13,680	1
				493,868		493,868	2
			-8,400			-8,400	3
					2,581	2,581	4
4,284				333,374		333,374	5
1,519				145,634		145,634	6
12,926				750,533		750,533	7
65				5,018		5,018	8
345				32,628		32,628	9
115				11,997		11,997	10
21,445			5,967,493	311,350		6,278,843	11
			2,823,570		5,853	2,829,423	12
			1,043,500			1,043,500	13
			7,062,750			7,062,750	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

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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)	
2,444,786			13,090,000	176,130,422		189,220,422	1
225,101			66,735,040	4,304,821		71,039,861	2
170,816			47,995,931	6,108,939		54,104,870	3
610,562			144,100,028	14,911,942		159,011,970	4
9,205				2,198,263		2,198,263	5
23,594			5,116,608	470,435	17,252	5,604,295	6
24,440			5,110,517	454,456	19,528	5,584,501	7
49,291			4,901,984	289,624	14,072	5,205,680	8
1,010				97,485		97,485	9
2,780				357,040		357,040	10
			-14,000			-14,000	11
53,675				2,600,421		2,600,421	12
36,640				3,313,680		3,313,680	13
34,247				4,775,921		4,775,921	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
1,300				99,087		99,087	1
15,148			1,594,271	228,639		1,822,910	2
5,771			1,991,101	98,461		2,089,562	3
			308,818	6,896		315,714	4
52,498				4,828,798		4,828,798	5
			58,300			58,300	6
4,774				356,758		356,758	7
988				74,727		74,727	8
2,550				374,862		374,862	9
41,451				4,053,982		4,053,982	10
			-7,000			-7,000	11
19,338				3,150,399		3,150,399	12
361,786				45,952,702		45,952,702	13
98,274				15,905,505		15,905,505	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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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)	
259,275				29,835,654		29,835,654	1
50,238				7,483,620		7,483,620	2
743,347				120,023,403	-8,290,000	111,733,403	3
4,260				329,659		329,659	4
-839,230			-36,250	-12,454,173		-12,490,423	5
5,429				634,767		634,767	6
274,059				35,475,740		35,475,740	7
12,149				1,367,301		1,367,301	8
17,993				1,677,878		1,677,878	9
			5,079,000			5,079,000	10
			1,050,000			1,050,000	11
2,377				349,773		349,773	12
			3,937,500			3,937,500	13
			2,812,500			2,812,500	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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)	
-210,000				-2,983,957		-2,983,957	1
527,904			54,851,012	5,320,613		60,171,625	2
75,408				9,082,148		9,082,148	3
3,546				521,057		521,057	4
				2,448	1,224	3,672	5
78,375				2,860,181		2,860,181	6
10,647				2,635,422		2,635,422	7
33,809				8,382,356		8,382,356	8
35,522				8,805,355		8,805,355	9
149,034			-643,150	3,731,979		3,088,829	10
-500,000				-7,000,000		-7,000,000	11
62,170			-2,846,200	2,254,113		-592,087	12
				65,814	-176,806	-110,992	13
3,866				568,906		568,906	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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)	
3,884				572,513		572,513	1
					270	270	2
			-14,000			-14,000	3
2,966				404,281		404,281	4
3,132				419,941		419,941	5
2,932				396,527		396,527	6
				532,442		532,442	7
				204,791		204,791	8
207,494				48,534,395		48,534,395	9
410,960				84,867,593		84,867,593	10
			331,054	-109,376		221,678	11
1,185,978			6,545,000	95,952,014		102,497,014	12
68,412				7,696,264		7,696,264	13
73,309				8,418,282		8,418,282	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report End of 2017/Q4

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

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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)	
144				13,084		13,084	1
566				49,471		49,471	2
1,095				136,248		136,248	3
948				129,064		129,064	4
538				75,161		75,161	5
19,669			8,592,773	659,469		9,252,242	6
38,518			8,508,283	630,978		9,139,261	7
843,395			67,706,603	10,955,458		78,662,061	8
				19,403,942	861,189	20,265,131	9
286,923				30,006,446		30,006,446	10
249,577				26,135,065	-850,000	25,285,065	11
512,668				66,556,056		66,556,056	12
28,931				3,543,649		3,543,649	13
107,078				14,716,282		14,716,282	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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.
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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)	
3,984				526,434		526,434	1
192,178				11,242,431		11,242,431	2
7,265				4,865,624		4,865,624	3
				9,350	91,525	100,875	4
2,572				330,166		330,166	5
91,718				15,310,790		15,310,790	6
77,994				13,844,020		13,844,020	7
1,710				154,523		154,523	8
88				2,143		2,143	9
12,671				818,977		818,977	10
10				714		714	11
53,131				4,634,541		4,634,541	12
701,894			22,506,444	26,395,801		48,902,245	13
2,936				410,500		410,500	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
2,977				415,688		415,688	1
1,464				204,305		204,305	2
190,282				16,245,845		16,245,845	3
3,445				447,966		447,966	4
4,174				302,442		302,442	5
1,188				169,687		169,687	6
24,330			3,903,454	444,881		4,348,335	7
5,377				541,689		541,689	8
2,440				246,724		246,724	9
				1,074	-1,455,289	-1,454,215	10
3,561				267,703		267,703	11
1,642				117,807		117,807	12
3,494				265,700		265,700	13
7,399				657,408		657,408	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
58,688				5,069,568		5,069,568	1
96,173				8,771,435		8,771,435	2
			-103,500			-103,500	3
136,074			29,345,351	2,418,804		31,764,155	4
203,722			118,263,757	4,168,853		122,432,610	5
111,731			595,943	3,905,274		4,501,217	6
2,169				102,112		102,112	7
3,604				-269,652		-269,652	8
22,813			3,885,616	319,394		4,205,010	9
300,322				6,022,918		6,022,918	10
3,541				471,028		471,028	11
271,523				41,050,276		41,050,276	12
675,489			14,700,088	913,346		15,613,434	13
2,046				156,938		156,938	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
3,545				473,396		473,396	1
591,277				115,924,521		115,924,521	2
38,345				3,567,797		3,567,797	3
99,197			682,500	3,555,390	-114,781	4,123,109	4
80,279			1,852,500	3,053,505		4,906,005	5
230,315				30,050,776		30,050,776	6
1,387				140,698		140,698	7
4,113				358,936		358,936	8
7,596				745,440		745,440	9
49,011				3,262,009		3,262,009	10
89,053			-24,500	8,994,381		8,969,881	11
199,063				20,306,690	-585,000	19,721,690	12
3,080			-30,302	424,511		394,209	13
756				83,794		83,794	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
189,184				9,986,258		9,986,258	1
254,749				12,073,510		12,073,510	2
470,332				40,876,165		40,876,165	3
155,596				19,844,397		19,844,397	4
161,713				23,544,652	-2,150,000	21,394,652	5
			19,025			19,025	6
46,185				4,639,296		4,639,296	7
834				123,916		123,916	8
1,465				203,793		203,793	9
51,101				4,363,324		4,363,324	10
29,706				3,812,337	285,709	4,098,046	11
439			1,078,291	11,703		1,089,994	12
28				3,601		3,601	13
					3,684	3,684	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

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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)	
1,205				131,325		131,325	1
121				12,135		12,135	2
650				93,759		93,759	3
-329,433				-4,773,484		-4,773,484	4
			-544,500			-544,500	5
-90,567			-297,000	-1,312,316		-1,609,316	6
			-2,603,750			-2,603,750	7
967,226				52,740,422		52,740,422	8
107,633				9,127,826		9,127,826	9
26,064				1,657,030		1,657,030	10
56,319				7,026,582		7,026,582	11
1,047				160,083		160,083	12
535				80,710		80,710	13
2,707				409,550		409,550	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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)	
4,820				473,262		473,262	1
19,311			8,059,800	469,259		8,529,059	2
56,060				3,505,983		3,505,983	3
2,048				147,207	-34,670	112,537	4
2,736				197,322		197,322	5
366				39,259		39,259	6
403				43,826		43,826	7
8,133				786,019		786,019	8
			-139,554			-139,554	9
136,689				23,661,812		23,661,812	10
35,721				3,269,331		3,269,331	11
16,626				1,699,218		1,699,218	12
80,750			1,486,020	2,712,417		4,198,437	13
58,202				3,324,701		3,324,701	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
118,477				6,571,738		6,571,738	1
307,164				24,660,721		24,660,721	2
122,751				10,855,167		10,855,167	3
169,389				19,438,079		19,438,079	4
84,308				9,674,344		9,674,344	5
272,369				24,513,217		24,513,217	6
97				11,840		11,840	7
336,484				31,215,220		31,215,220	8
				1,975	25,698	27,673	9
696				34,099		34,099	10
			-158,400			-158,400	11
141,020				22,101,516		22,101,516	12
157,336				25,158,842		25,158,842	13
			-634,040			-634,040	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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.
448,229			3,551,259	15,359,726		18,910,985	1
99				10,247		10,247	2
8,866				451,826		451,826	3
8,805				447,986		447,986	4
17,813				792,973		792,973	5
17,984				747,898		747,898	6
66,710			13,580,561	963,470		14,544,031	7
3,692				289,202		289,202	8
33,642				1,533,855		1,533,855	9
			13,595,200			13,595,200	10
129,193				15,621,993		15,621,993	11
160				3,828		3,828	12
50,017			315,283	2,128,938		2,444,221	13
			-181,600			-181,600	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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)	
6,980				694,450		694,450	1
1,228,886				211,794,497	-25,500,000	186,294,497	2
10,224				1,110,048		1,110,048	3
304,227				9,640,921	2,060,601	11,701,522	4
878				91,614		91,614	5
1,467				138,652		138,652	6
2,532				294,589		294,589	7
			193,087	9,998,881		10,191,968	8
261,749				26,251,603		26,251,603	9
231,729				25,028,140	-655,000	24,373,140	10
104				10,859		10,859	11
3,985				587,795		587,795	12
186,946				16,618,838		16,618,838	13
3,870				305,214		305,214	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
				8,133		8,133	1
59,072				4,893,679		4,893,679	2
53,135				3,529,035		3,529,035	3
				120,696	1,303	121,999	4
43,266				5,659,689		5,659,689	5
47,559				2,405,118		2,405,118	6
16,369				1,713,855		1,713,855	7
16,794				2,932,820		2,932,820	8
13,953				1,025,842		1,025,842	9
48,998				3,615,991		3,615,991	10
527				60,923		60,923	11
3				204		204	12
1,187				122,876		122,876	13
165,911				16,920,831		16,920,831	14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
24,112				1,623,806		1,623,806	1
12,567				955,742		955,742	2
1,187				83,120		83,120	3
2,316				283,442		283,442	4
2,385				292,263		292,263	5
6,257				802,463		802,463	6
							7
							8
							9
					-1	-1	10
					12,543,701	12,543,701	11
					4,133	4,133	12
					2,363	2,363	13
							14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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
53,443					8,005,413	8,005,413	2
5,097					709,071	709,071	3
					204,641	204,641	4
7,038,531					374,853,404	374,853,404	5
					80,302,280	80,302,280	6
					571,332	571,332	7
					587,096	587,096	8
					13,688,179	13,688,179	9
							10
							11
							12
							13
							14
34,369,444			858,047,042	2,539,550,440	455,014,143	3,852,611,625	

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	03/09/2018	End of 2017/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1				
2				
3				
4				
5				
6				
7				
8				
9	SF BAY AREA RAPID TRANSIT (BART)	NCPA/WAPA	SF BART	LFP
10				
11				
12	TRANSMISSION AGENCY OF			
13	NORTHERN CALIFORNIA (TANC)	Various	Various	LFP
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
12	COTP Terminus/Tracy	Various	66	33,248	32,301	9
						10
						11
						12
143	Midway	Various	233	564,566	553,890	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			299	**597,814**	**586,191**	

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	03/09/2018	End of 2017/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
348,490		-349,000	-510	9
				10
				11
				12
	2,841,292	-10,000	2,831,292	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
348,490	**2,841,292**	**-359,000**	**2,830,782**	

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 9 Column: a

BART's contract expired on December 31, 2016.

Schedule Page: 328 Line No.: 13 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	03/09/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	California - Oregon							
2	Transmission Project	OS					425,699	425,699
3	Pacificorp	OS			12,500,000		261,595	12,761,595
4	Sacramento Municipal							
5	Utility District	OS						
6	Western Area Power							
7	Administration	OS			2,216			2,216
8	California-Oregon							
9	Intertie	OS					475,555	475,555
10	Other	OS						
11								
12								
13								
14								
15								
16								
	TOTAL				12,502,216		1,162,849	13,665,065

FOOTNOTE DATA

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

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	03/09/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
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	-172,708
7	Intercompany Billings Timing Difference	-28,932
8	Intervenor Compensation	2,135,978
9	MCI-PG&E Exchange Rights	691,661
10	Bank Service Fees	3,940,650
11	Gift Cards for Campaign for Community	15,970
12	Gift Cards for Fire Relief	51,148
13	Union Negotiation Adjustment	260,118
14	Non-PO Credit Memo's	-398,989
15	Misc. cash receipt (recovery of unclaimed funds)	-103,885
16	Other miscelleneous adjustments	-84,568
17		
18		
19		
20		
21		
22		
23		
24		
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27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	6,306,443

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			2,544,016		2,544,016
2	Steam Production Plant	19,888,371				19,888,371
3	Nuclear Production Plant	225,236,758			38,731,572	263,968,330
4	Hydraulic Production Plant-Conventional	70,720,680			4,752,000	75,472,680
5	Hydraulic Production Plant-Pumped Storage	11,949,698			2,280,000	14,229,698
6	Other Production Plant	45,498,767				45,498,767
7	Transmission Plant	275,893,033				275,893,033
8	Distribution Plant	1,151,509,666				1,151,509,666
9	Regional Transmission and Market Operation					
10	General Plant	24,163,899				24,163,899
11	Common Plant-Electric	155,934,823		188,961,823		344,896,646
12	TOTAL	1,980,795,695		191,505,839	45,763,572	2,218,065,106

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 64.90%.

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	03/09/2018	End of 2017/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	Intangible Plant						
13	302	113,936	40.00		2.19	SQ	22.60
14	303	4,126	4.00		1.60	SQ	-13.50
15	Subtotal	118,062					
16							
17	Steam Prod - Fossil						
18	310	4,801			2.18	SQ	-3.30
19	311	113,561	75.00		3.46	R1	19.70
20	312	276,508	50.00		3.68	R1	19.40
21	313						
22	314	257,380	40.00		3.56	R2.5	20.20
23	315	52,596	45.00		3.55	R2.5	21.60
24	316	28,349	40.00		3.77	S0.5	19.00
25	Subtotal	733,195					
26							
27	Hydraulic Production						
28	330	17,311			1.92	SQ	-13.40
29	331	499,508	80.00	-2.00	1.69	R2	11.70
30	332	2,080,010	120.00	-3.00	1.59	R2.5	14.40
31	333	956,052	82.00	-3.00	3.10	R1	14.00
32	334	271,542	65.00	-6.00	3.01	R1.5	11.60
33	335	94,926	60.00	-9.00	3.36	S0.5	11.40
34	336	85,008	80.00	-2.00	2.43	S1.5	9.30
35	Subtotal	4,004,357					
36							
37	Nuclear Prod - Diablo						
38	321	1,085,773	100.00	-1.00	1.50	R1	4.60
39	322	3,517,474	65.00	-1.00	2.68	S1	15.70
40	323	1,170,599	50.00	-1.00	1.50	S2	5.70
41	324	845,868	75.00		1.48	R1.5	5.60
42	325	1,147,521	50.00	-1.00	5.42	S1	6.80
43	Subtotal	7,767,235					
44							
45	Other Production						
46	340	3,121			0.64	SQ	-1.20
47	341	210,604	51.00		3.69	R1,SQ	12.20
48	342	11,271	50.00		3.69	R1	19.60
49	343	226,088	40.00		3.57	R2.5	20.30
50	344	353,681	-2.00		4.35	R2.5,SQ	-8.80

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	03/09/2018	End of 2017/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	345	212,858	25.00		5.68	R2.5,S2.5,SQ	10.20
13	346	97,458	26.00		3.84	S0.5,SQ	10.70
14	Subtotal	1,115,081					
15							
16	Transmission						
17	350	199,076	38.00		1.82	R4	21.50
18	352	500,210	65.00	-20.00	1.80	R3	55.70
19	353	6,040,240	2.00		0.08	R1.5	0.90
20	354	916,389	75.00	-66.00	2.25	R4	55.30
21	355	1,176,798	52.00	-65.00	2.99	R1.5	41.90
22	356	1,537,254	65.00	-70.00	2.57	R2	48.90
23	357	504,787	65.00		1.52	R4	54.60
24	358	272,630	55.00	-10.00	1.99	R3	42.90
25	359	85,866	60.00	-10.00	1.91	R1.5	50.50
26	Subtotal	11,233,250					
27							
28	Transmission - Diablo						
29	352.01	6,201	65.00	-20.00	1.48	R3	12.50
30	353.01	89,964	98.00	-28.00	7.05	R2	43.70
31	Subtotal	96,165					
32							
33	Distribution						
34	360	117,390	40.00		2.10	SQ	18.80
35	361	327,286	65.00	-20.00	1.78	R3	47.60
36	362	3,356,709	46.00	-40.00	3.06	R1.5	32.80
37	363	33,233	15.00		6.49	R2,S3	10.10
38	364	4,324,895	44.00	-150.00	6.03	R1.5	30.30
39	365	4,667,425	46.00	-125.00	5.05	R2	31.50
40	366	2,861,012	62.00	-50.00	2.60	R4	44.00
41	367	4,555,768	47.00	-65.00	3.35	R3	31.00
42	368	3,451,756	32.00	-28.00	4.40	R2.5,R3	20.80
43	369	3,274,116	47.00	-67.00	3.50	R2.5,R4	27.60
44	370	1,157,714	20.00	-15.00	6.21	R1.5	13.90
45	371	27,314	40.00			S1	5.70
46	372	895	25.00			L1	-16.50
47	373	231,779	28.00	-23.00	3.24	R0.5,S1.5,L0,S1	9.30
48	Subtotal	28,387,292					
49							
50	General Plant						

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	03/09/2018	End of 2017/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	389	415	59.00		2.74	SQ	31.80
13	390	11,255	50.00	-10.00	1.62	R2	30.60
14	391	11,281	20.00		6.20	SQ	11.40
15	394	129,933	25.00		3.85	SQ	17.40
16	395	14,556	20.00		5.37	SQ	13.20
17	396	271	20.00		6.63	SQ	0.50
18	397	282,496	15.00		6.24	SQ	13.00
19	398	11,367	20.00		13.04	SQ	12.70
20	Subtotal	461,574					
21							
22	General Plant Diablo						
23	391.01	4,347	20.00		5.23	SQ	17.40
24	398.01	15,790	20.00		5.39	SQ	16.90
25	Subtotal	20,137					
26							
27	Total	53,936,348					
28							
29							
30							
31							
32							
33							
34							
35							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Annual fees paid for Diablo Canyon Power Plant				
2	in accordance with Part 171				
3	Docket# 05000275	4,078,389		4,078,389	
4	Docket# 05000323	4,078,389		4,078,389	
5					
6	Fees paid for Diablo Canyon Power Plant				
7	for inspection, license renewal, operator				
8	examination in accordance with Part 170				
9	Docket# 05000275	1,265,698		1,265,698	
10	Docket# 05000323	1,088,440		1,088,440	
11	General Accrual	-270,200		-270,200	
12					
13	Annual fees paid for Diablo Canyon Power Plant				
14	in accordance with Part 171				
15	Docket# 05000275	327,611		327,611	
16	Docket# 05000323	327,611		327,611	
17					
18	Fees paid for Diablo Canyon Power Plant				
19	for inspection, license renewal, operator				
20	examination in accordance with Part 170				
21	Docket# 05000275	74,351		74,351	
22	Docket# 05000323	90,318		90,318	
23	General Accrual	100,000		100,000	
24					
25	Fees paid for Diablo Canyon Power Plant				
26	for inspection, license renewal, operator				
27	examination in accordance with Part 170				
28	Docket# 05000275	68,892		68,892	
29	Docket# 05000323	68,956		68,956	
30	Docket# 07200026	59,095		59,095	
31	General Accrual	-88,000		-88,000	
32					
33	Fees paid for Diablo Canyon Power Plant				
34	for inspection, license renewal, operator				
35	examination in accordance with Part 170				
36	Docket# 05000275	274,807		274,807	
37	Docket# 05000323	204,575		204,575	
38	General Accrual	-475,000		-475,000	
39					
40	Annual fees paid for Humbolt Bay Power Plant				
41	in accordance with Part 171 (Docket# 05000133)	185,750		185,750	
42					
43	*All paid to US Nuclear Regulatory Commission				
44					
45					
46	TOTAL	11,459,682		11,459,682	

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	4,078,389					3
	524	4,078,389					4
							5
							6
							7
							8
	524	1,265,698					9
	524	1,088,440					10
	524	-270,200					11
							12
							13
							14
	532	327,611					15
	532	327,611					16
							17
							18
							19
							20
	532	74,351					21
	532	90,318					22
	532	100,000					23
							24
							25
							26
							27
	107	68,892					28
	107	68,956					29
	107	59,095					30
	107	-88,000					31
							32
							33
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	101	274,807					36
	101	204,575					37
	101	-475,000					38
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	524	185,750					41
							42
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							45
		11,459,682					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	03/09/2018	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A2, A3	Electric Program Investment Charge
2		
3		
4		
5		
6	A2, A3	Customer Energy Services -
7		Cyber Security and Grid Innovation
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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	03/09/2018	End of 2017/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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
18,907,157		408	527,895		1
		456	-194,024		2
		588	17,043,532		3
		926	1,529,755		4
					5
3,742,491		408	36,304		6
		588	3,599,033		7
		926	107,154		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	03/09/2018	End of 2017/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	233,942,839		
4	Transmission	75,098,241		
5	Regional Market			
6	Distribution	146,682,567		
7	Customer Accounts	114,179,976		
8	Customer Service and Informational	63,601,046		
9	Sales	956,734		
10	Administrative and General	315,885,592		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	950,346,995		
12	Maintenance			
13	Production	107,525,090		
14	Transmission	27,335,908		
15	Regional Market			
16	Distribution	206,895,558		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	341,756,556		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	341,467,929		
21	Transmission (Enter Total of lines 4 and 14)	102,434,149		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	353,578,125		
24	Customer Accounts (Transcribe from line 7)	114,179,976		
25	Customer Service and Informational (Transcribe from line 8)	63,601,046		
26	Sales (Transcribe from line 9)	956,734		
27	Administrative and General (Enter Total of lines 10 and 17)	315,885,592		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,292,103,551		1,292,103,551
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	2,927,838		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	3,751,119		
35	Transmission	96,109,714		
36	Distribution	146,342,405		
37	Customer Accounts	71,380,424		
38	Customer Service and Informational	15,487,163		
39	Sales	562,831		
40	Administrative and General	141,344,619		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	477,906,113		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)	135,232		
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,171,007		
47	Transmission	59,685,092		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	68,008,410		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	128,999,741		
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,	3,063,070		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	4,922,126		
56	Transmission (Lines 35 and 47)	155,794,806		
57	Distribution (Lines 36 and 48)	214,350,815		
58	Customer Accounts (Line 37)	71,380,424		
59	Customer Service and Informational (Line 38)	15,487,163		
60	Sales (Line 39)	562,831		
61	Administrative and General (Lines 40 and 49)	141,344,619		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	606,905,854		606,905,854
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	1,899,009,405		1,899,009,405
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	765,543,685		765,543,685
69	Gas Plant	390,711,090		390,711,090
70	Other (provide details in footnote):	170,188,982		170,188,982
71	TOTAL Construction (Total of lines 68 thru 70)	1,326,443,757		1,326,443,757
72	Plant Removal (By Utility Departments)			
73	Electric Plant	53,097,358		53,097,358
74	Gas Plant	21,474,259		21,474,259
75	Other (provide details in footnote):	574,026		574,026
76	TOTAL Plant Removal (Total of lines 73 thru 75)	75,145,643		75,145,643
77	Other Accounts (Specify, provide details in footnote):			
78	Other Balance Sheet Salaries and Wages	9,786,474		9,786,474
79	Other Non-Operating Salaries an Wages	11,506,839		11,506,839
80				
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95	TOTAL Other Accounts	21,293,313		21,293,313
96	TOTAL SALARIES AND WAGES	3,321,892,118		3,321,892,118

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	03/09/2018	End of 2017/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.

COMMON UTILITY PLANT IN SERVICE

Acct No.	Description	Balance Beginning of Year	Additions	Retirements	Transfers and Adjustments	Balance End of Year
301	Organization	1,567,901	5,433,212	0	(6,868,702)	132,411
302	Franchises/Consents	214,735	0	0	0	214,735
303	Intangible Plant	1,739,436,765	165,795,304	(216,139,832)	0	1,689,092,237
	Total Intangible Plant	1,741,219,401	171,228,516	(216,139,832)	(6,868,702)	1,689,439,383
389	Land and Land Rights	83,247,899	8,801,982	0	(808,194)	91,241,687
390	Structures and Improvements	1,487,653,456	179,269,874	(9,898,095)	0	1,657,025,235
391	Personal Computer Hardware	106,816,775	11,588,932	(24,173,797)	0	94,231,910
391	Office Machines	385,227,917	52,828,490	(124,127,753)	6,793,847	320,722,501
391	Office Furniture and Equipment	108,418,637	17,596,454	(6,681,126)	0	119,333,965
392	Transportation Equipment	1,086,517,443	73,058,936	(90,948,592)	0	1,068,627,787
393	Stores Equipment	8,674,216	821,137	(77,109)	0	9,418,244
394	Tools, Shop, and Garage Equipment	68,349,820	464,919	0	74,855	68,889,594
395	Laboratory Equipment	10,847,008	1,105	(1,053,925)	0	9,794,188
396	Power Operated Equipment	166,063,707	16,585,788	(5,035,698)	0	177,613,797
397	Communication Equipment	1,128,918,092	77,082,003	(34,569,927)	0	1,171,430,168
398	Miscellaneous Equipment	27,127,736	16,013,687	(1,783,497)	0	41,357,926(a)
399	Other Tangible Property	679	0	0	0	679
	Total Non-Landed	4,584,615,486	445,311,325	(298,349,519)	6,868,702	4,738,445,994
	Total	6,409,082,786	625,341,823	(514,489,351)	(808,194)	6,519,127,064
101	Property Under Capital Leases	18,230,721	0	0	0	18,230,721
101	Plant Purchased/Sold	442,508	0	0	442,508)	0
	Total Common Utility Plant in Service	6,427,756,015	625,341,823	(514,489,351)	(1,250,702)	6,537,357,785
107	Construction Work in Progress - Common Utility Plt.	319,987,776	69,548,572	0	9,188,153	398,724,501
	Total Common Utility Plant	6,747,743,791	694,890,395	(514,489,351)	7,937,451	6,936,082,286

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/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.
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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.

NOTES:

(a) Included in the 12/31/17 FERC account 398 plant balance is $26,835,220 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)	6,537,357,785	4,243,052,240	2,294,305,546
Accumulated Provision for Depreciation (a)	2,618,030,616	1,768,217,878	849,812,738

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)	417,207,273	314,842,534	102,364,739
Common Utility Plant (a) included in above amount	32,137,917	20,859,018	11,278,899

NOTES:

(a) 2017 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).

Electric	Gas

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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COMMON UTILITY PLANT AND EXPENSES

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Common Plant in Service Allocation Factors	64.90%	35.10%
Common Plant Accumulated Depreciation Allocation Factors	67.54%	32.46%

(b) Amounts are based on direct charges. Not included in the total was $362,370 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	230,877,736	155,934,823	74,942,913
Amortization	404	279,777,647	188,961,823	90,815,824
Total		510,655,383	344,896,646	165,758,737

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	12,472,806	8,482,617	3,990,188

Note: Operation expense data was not available.

CONSTRUCTION WORK IN PROGRESS (CWIP) - COMMON (ACCOUNT 107)

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COMMON UTILITY PLANT AND EXPENSES

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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.

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Description of Project                                   Amount
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7087386 Vacaville Critical Ops Center - Bldg 4   25,484,196
70035504    IO - Exit Legacy Data Centers    15,828,842
7090505 Corp Security-Replacement of Legacy CCTV     9,662,582
7085486 Fresno Thorne Yard - Renovation  8,901,241
70028327    Customer Revenue Critical Reporting CAP  8,560,780
7087426 Lemoore SC / Coalinga SC - Consolidatn   8,289,173
70031424    Asset Inspection (GD) - CAP  8,266,642
70026660    Pole Loading Tool Upgrade with Industry  6,653,768
70026620    IT PM Tools Improvement Release 3 - Prim     6,383,113
70030841    Windows 10 Upgrade Ph 1 (CAP)    5,356,074
70032527    Asset Inspection (ED) - CAP  5,302,400
70031801    CCA Expansion- PHASE 2 Cap   5,031,508
70032940    ITSM Remedy Upgrade  4,979,627
70030661    Mobile MRAD Platform (GD) Cap    4,938,000
7091625 System ETI-Trailer Upgr Pgrm (2017)  4,929,283
7091449 Facility Asset Upkeep North  4,599,262
70035749    SAP Roadmap Foundational Upgrade     4,526,707
7089965 Livermore Sub Training - New Facility    4,401,987
7091450 Facility Asset Upkeep South  4,352,087
70028908    DR - Meter Data Management System (MDMS)     4,034,943
7089806 Bay Area Program - GO/East Bay (CAR 1C)  3,898,996
7089825 Appian AMPs  3,804,148
70031423    Asset Inspection (ET) - CAP  3,789,251
70034960    IO - WiFi Everywhere - Field Sites   3,525,774
7089865 Vacaville Crit Ops Cntr-Bldg5 Gas Ctrl Bckup 3,398,325
70034680    2017 Field Area Network  3,323,601
70032740    Copper Fiber Replacement - Pit   3,318,444
70030600    Mobility RFP - Cap   3,049,814
70034340    IO-DC-2017 Stor Lifecycle-EMC EDL (VTL)  2,958,135
70035220    ST - Security Enclave (CAP)  2,848,182
70034385    ST - IAM - ARI OIM Backlog   2,846,883
7091946 Stockton Regional Ofc-Upgrades (PH2)_PV  2,809,913
70030468    System Tool for Asset Risk ED - (Cap)    2,698,789
70030465    System Tool for Asset Risk ET - (CAP)    2,647,492
70031241    Mobile MRAD Platform (ET) CAP    2,637,607
70034968    IO - Pure Flex Remediation   2,621,341
70031245    Mobile MRAD Platform (GTS) Cap   2,621,007
70032528    Mobile MRAD Platform (ED) - CAP  2,594,698
70035543    ST - Cyber Full Packet Capture (CAP)     2,554,197
70033776    Cust Revenue Critical Reporting - BT CAP     2,546,954
7088089 Vacaville Crit Ops Cntr-Bldg4 (IT Infra)_I   2,475,857
7090986 San Ramon TC - Upgrades (PH2)    2,443,140
7092087 GSA - Specialized Training Venues    2,396,863
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.

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70033543    IM - Int Infra & App Lifecycle 2017 CAP  2,368,160
7089345 Electric Load Forecast   2,365,596
7087511 Antioch SC - Renovation  2,316,180
70032942    OP: AMSM - Intgrtd IT Port Anlys (IIPA)  2,254,717
7090825 Corp Security-SIS Replacement-Capital    2,206,417
70034620    IO - ODN One Cloud Light     2,205,064
70032886    ST Tools Net Lifcyc Upgrd Sec Zn Strat   2,162,902
70033625    Endur Upgrade    2,144,358
70032450    Position Description and Attributes  2,105,035
70030481    Customer Care Mainframe Transition - cap     1,982,204
70031143    IM:AO DBSVR Security Enhancements CAPITA     1,972,707
7091451 Facility Asset Upkeep Break/Fix  1,962,497
7089925 Rocklin GCC - Perimeter Wall     1,950,700
70028100    Los Banos Sub Fiber Install-C    1,935,953
70033923    SQMD Replacement Phase 3     1,910,376
7086328 Merced SC - New Site/Facility    1,874,528
7090506 Corp Security-Upgrade of SF Comm Center  1,744,383
70032920    ST VlnMgmt Vulnerability Mgmt Prg Redsgn     1,712,360
7090331 System - SC Security Program     1,675,279
70033623    ODMS Ph5     1,640,574
70033361    Mobile MRAD Platform (FG) Cap    1,624,050
70033363    Mobile MRAD Platform (HG) Cap    1,623,116
70033362    Mobile MRAD Platform (NG) Cap    1,623,116
70032703    ECP: Business CUCM Cluster Upgrade   1,584,579
70027401    ESOMS Upgrade CAP    1,527,253
70021400    MobileConnect for ET Compliance  1,508,010
70030942    iSAP 2.0 (Part 1) CAP    1,486,755
7091572 GTCC Predictive Health Analytics     1,484,817
70033234    DCPP Security Screening Information Syst     1,460,333
7092125 DREBA2017-R24 CLICKTHRU-P1-IT-Sol3-CAP   1,426,129
70029487    2015 Oracle DB_Audit Rem & Data Sec Enh  1,411,975
70033583    OP: AMSM-Asset Mgmt Pltfrm & Srvcs (AMPS     1,388,224
70033550    GAME GTS (Cap)   1,387,492
70035860    IGNIO Tool Deployment    1,342,076
7090427 Facility Asset Upkeep    1,337,422
70033065    Enterprise Compliance Management Tool CA     1,314,288
70034601    Express Connects (calc) (CAP)    1,242,771
70033746    ED - GIS Data Quality Improvement    1,230,518
70033281    EA Retire Unsupported Tech Platform CFA  1,228,186
70034824    WiFi Everywhere - SFGO   1,220,199
70029346    Wesley Fiber Install     1,216,825
7088806 Diablo Valley Office - Consolidation     1,169,341
70035502    ST - 2018 Lifecycle Replacement (Cap)    1,159,808
70033750    Super Electric Ops   1,119,110
70033702    Microwave Capacity Increase (TO)     1,110,426
70033126    Scheduled, Courtesy & Web Call Back  CAP     1,102,180
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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	03/09/2018	End of 2017/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.
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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.

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7091945 FM Energy Efficiency Upgr Prog (CAR)     1,101,776
70033607    ERIM IT Centralized Records Management   1,100,533
70031142    IM:AO DBSVR OEM Enhancements CAPITAL     1,079,960
70033922    CAISO Fall 2017 Release  1,064,781
70030740    Enterprise Mobile 2016 - CAP     1,062,864
7074466 Tracy Sub to Bethany Cmprsr Stn Fbr Bld  1,052,061
70030800    2016 SCADA TELEPROTECTION    1,047,901
70034641    Advancing IVR System Phase 3- Cap    1,045,354
7090065 CI: GRC & Rate Reform Analysis Enhanceme     1,038,623
70032529    Linear Inspection (ED) - CAP     1,038,609
7092586 FLISR Dashboard  1,021,652
7091251 Vacaville Crit Ops Cntr-Bldg6 New Warehouse  1,021,274
70035445    IO - SmartMeterSSN Transition PG&E (CAP)     1,019,889
7090645 System ETI - Trailer Upgrade Program_C   1,000,626
70032944    ECP: Verint Lifecycle Replcmnt Proj Ph 2     992,730
70033757    Substation Record and RecordKeeping Impr     985,045
7089525 Bill Determinant FCST & Analyt Long Term     980,519
70030413    Cyber: Windows XP Migration CAP Transmis     978,309
7092006 Auburn Regional Center-B5 Fleet Building     971,269
70028913    DR - Set 7: FiberOpticGIS    966,790
7092045 SFGO - Conference Rooms Refresh (IO)     932,155
7084987 Modesto SC Fiber Build   920,222
70032961    CIP003-WP04A Low Impact Methodology  908,863
70033226    FFMO CAP     873,831
7088935 CI: Mainframe Migration Gas  865,697
7091447 SFSC - Relocation (Gas/Electric)     858,845
70035600    Future Est Workstation Tech(Cap)     848,960
70028915    DC - OSI Pi Platform Capacity    829,860
70034081    Data Historian (ED Pi Phase 2)   823,465
70035447    DCPP Network Switch and WiFi Replacement     809,178
7091573 GDCC Predictive Health Analytics     803,984
70033669    Gas Qualification - System Data Automati     786,641
7085346 77 Beale GO - Upgrades (Lobby)   785,174
70034495    Vulnerability Management Program     776,307
70033201    IO-2017 Teleprotection Lifecycle (TO)    772,313
70035680    SAP DR - High Availability / DR  768,984
70034863    DR - Set 8:  Smart meter - SMH   763,203
70031425    Asset Inspection (GTS) - CAP     757,850
70033942    Software Asset Management Phase2             755,501
7091405 System - Material Rack Upgrades  738,365
70033825    ST - IAM Priority Apps SOX Intg (CAP)    732,587
7084985 Templeton SC-Sub Fiber Build     715,721
70029407    Radio Reliability - Alcade ET    715,558
70031255    Hat Creek Network Extension  710,376
7088763 Electric Storage Containers  691,092
70026860    Table Mtn Sub Fiber Install  682,467
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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	03/09/2018	End of 2017/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.
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7092605 CAP-EV CHARGING STATION DATA INTEGRATION     677,344
70033693    (GTCC) Enhancements  675,683
7086212 77 Beale GO - Mech Upgrd(Fans 6-7-11-12)     664,643
70033670    GD GIS Enhancements  655,251
70033668    (GDCC) Enhancements CAP  633,351
70033227    HR Component of ECP Enterprise   622,141
70033553    ST - IAM - Privileged Access Mgmt (CAP)  621,445
70029804    Adtran Tracer MW Radio MW Replacement    612,253
70029020    ES Cyber Enhance Network Segmentation-H  605,325
70033741    Express Connects Cap     603,998
70032180    Black Butte RS Tower Replacement     597,919
70033724    GeoMart  585,631
70033752    GeoMart  585,631
70033758    GeoMart  585,631
70033756    Bentley SAP Integration - Phase3     579,125
70034261    Corporate Security Depar Radio Project   578,611
70033699    Project Governance and Controls  570,397
70034491    DR - Set 7:  EG - Vegetation Management  559,637
7083729 TO Radio System Expansion - Gato Ridge   552,415
70032884    Edge Router Lifecycle Replacement- South     531,384
70030780    Motherlode - VoIP    529,223
70033544    ODN Cap Inc and Rel Impr (TO)    529,032
70034864    DR - Set 8:  TACACS+     526,899
70035401    Transformer Oil Analysis     524,674
70030692    DS0 Migration Project Phase II MPLS Peer     519,278
70033744    Permitting Process Initiative    516,452
70029122    TO Radio System Crestview    516,076
70035405    Increase Self Service Adoption - Cap     514,455
7092050 77 Beale GO-8th,27th Flrs Refresh (IO)   493,244
70029805    Black Butte to Red Rock Mountain PTP Upg     492,060
7091574 Network Improvements - Add Alternate     481,870
70035752    ITSM Remedy Upgrade - Discovery Tool     478,492
70028681    Radio Reliability - Mt Elizabeth     478,398
70035966    IO - DC - Organic Growth: SB Storage/DP  475,122
70030980    AO Database Security Vulnerability Remed     466,926
70033941    IO 2017 SCADA Terminal Server    459,228
70031243    Linear Inspection (HG) - CAP     452,878
70034160    TO-CIP Academy   451,909
70033205    Power Gen Records Management - cap   448,333
7090325 Auburn SC Regional GC Conversion     430,146
70033147    Pole Loading Tool Upgrade with Industry  423,738
70034487    DR - Set 7:  EG - MET    421,696
70031025    DS0 Migration Project Phase II (Testing)     416,852
7092007 Auburn Regional Center - B6 Haz Mat  412,507
70029124    Radio Reliability - Call Mt  412,484
70033720    Station Asset Hierarchy  412,420
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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	03/09/2018	End of 2017/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.
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7092090 Service Center Refresh Program - Area 2  409,593
70030702    FIP - MARYSVILLE SC  407,398
70033549    Cyber SS ST - 3rd Party Security and Ris     407,322
7091465 77 Beale GO - Relocation (Reg Affairs)   397,671
7086008 Radio Reliability - Rocks Road   397,436
70032660    VGCC-Sacramento Fiber Install    392,763
7083653 Radio Reliability - Carmel Valley    384,956
70034489    DR - Set 7:  EG - Control Room Alarm Man     378,504
70032902    Fiber Cable - Sacramento Fiber Cable Rep     377,008
70034827    Lease Standard Implementation CAP    363,007
70034383    ST - IAM - ARI Segregation of Duties (SO     360,898
70034565    Activating DRAC's T&D SCADA sites (GRC)  355,673
70034965    IO - DMR Migration Program - Lab Trial   349,438
7089807 Bay Area Program -GO/East Bay_I (CAR 1C)     345,138
70035500    DCPP Replace EDMS/RMS/Filenet PH2    344,792
70032263    Kings-Crane Grounding and Bonding    344,285
70035700    Cyber Vulnerability Mgmt - Skybox (Cap)  341,686
7085906 San Carlos SC - Repl Carpet/Generator    338,615
70035541    ST - IBM AppScan (Cap)   329,912
7092306 Facility Asset Upkeep - Area 2   328,194
70030562    Bishop Ranch Business Continuity Enhance     324,730
70034181    SONET Gates and Midway Sub Wvstr Rrtmnt  323,279
70032885    Telecom Network Synchronization  321,467
70035640    2017 10 Base Camp Build  321,195
7088091 Stockton Gas Plant - Renovation  319,651
70032201    Hitachi Data System Settlement   316,609
7091575 Network Improvements - Improve WAN   316,206
70032903    SONET A2R7 Wavestar Retirement   315,425
70030697    D080 SLO SC to Black Butte   313,964
7091303 San Carlos SC - Remove UST/Install AST   311,810
70035024    ST-Web Acc Mgmt (CA Sitemndr) Rep (CAP)  310,493
70031144    IM:AO DBSVR Migrate Windows DBs to Linux     309,419
7088485 Fresno Thorne Yard - Renovation_I    299,058
70027586    Radio Reliability - Lime Mt  292,163
70029581    EMS SMP Server Replacement   290,505
7091345 SFGO - Elec Upgrd (Controls & Alarms)    290,028
70029301    ES Cyber Enhance Network Segmentation-F  280,854
7091752 Auburn Garage - Two Lifts    280,772
70032183    D110 (Morro Bay - Tassajara)     277,061
70034662    Lights Out Management    276,562
7089287 Livermore SC - Relocation    274,184
70032905    Telecommunications Tower Program     273,013
70031242    Linear Inspection (ET) - CAP     272,588
70034243    TO-CIP GarretCom     267,648
70033848    Calc & Controls - P2     260,327
7089866 Vaca Crit Ops Cntr-Bldg5 Gas Cntrl Bckup_I   257,894
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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	03/09/2018	End of 2017/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.
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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.

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70029343    Integra Fiber Replace-North Tower to San     256,705
70033696    Cimplicity to PI for Compressor Stations     254,520
70033621    Kings-Crane Network Extension    253,633
7092289 Service Center Refresh Program - Area 7  251,043

                                                          -------------

Subtotal - Projects with more than $250,000
  in actual costs in CWIP, excluding Research,
  Development, & Demonstration jobs                       $375,757,684

Aggregate total of projects with less than $250,000 in actual
  costs in Construction Work in Progress, including credits
  representing preliminary billings.

                                                           $22,966,817
                                                         --------------

          TOTAL CWIP - COMMON                             $398,724,501
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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	03/09/2018	End of 2017/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	105,214,348	108,668,732	115,119,821	362,406,926
3	Net Sales (Account 447)	(3,112,076)	(4,534,295)	(33,430,177)	(114,339,999)
4	Transmission Rights				
5	Ancillary Services	2,226,430	918,698	(2,264,945)	2,203,393
6	Other Items (list separately)				
7	Grid Management Charges	12,025,463	12,403,212	14,751,445	51,070,148
8	FERC Fees	1,145,249	1,086,923	2,270,651	5,485,996
9	ISO Congestion				
10	Unaccounted for Energy	(5,325,039)	1,322,215	16,394,696	26,730,114
11	Congestion Revenue Rights - Hedge	(2,461,920)	(12,061,160)	(5,420,802)	(9,427,764)
12	Congestion Revenue Rights - Auction	(314,840)	(1,359,611)	(677,245)	(3,718,885)
13	Convergence Bidding	(531,974)	373,310	84,998	202,752
14	Other ISO-related charges:				
15	Minimum Load				
16	Neutrality	(1,427,270)	1,446,671	(120,913)	118,726
17	Voltage Support				
18	Other	1,175,052	(942,697)	2,476,983	6,812,248
19	Cost Recovery	(2,699,800)	(2,207,437)	(617,849)	(6,420,374)
20	Inter Day Ahead SC Trade				
21	Inter Real Time SC Trade				
22	Interest	14,525	(81,001)	161,515	169,703
23	Capacity - Other	1,140,844	2,102,653	1,442,899	5,374,702
24	DA IFM Credit Allocation	(9,043,345)	(11,020,049)	(14,471,589)	(44,072,318)
25	RT Offset/Allocation	4,409,363	11,558,641	3,285,665	27,301,534
26	Net Purchases for Energy Storage	48,676	42,302	74,348	204,641
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	102,483,686	107,717,107	99,059,501	310,101,543

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	03/09/2018	End of 2017/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch					N/A	18,000
2	Reactive Supply and Voltage				70,920	kW-Month	14,539
3	Regulation and Frequency Response				69,948	kW-Month	2,798
4	Energy Imbalance				24,349	kWh	2,435
5	Operating Reserve - Spinning				69,948	kW-Month	15,130
6	Operating Reserve - Supplement				69,948	kW-Month	15,007
7	Other		Various	12,066,416		Various	9,863,023
8	Total (Lines 1 thru 7)			12,066,416	305,113		9,930,932

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: b

With the exception of the Utility's contract with BART (OAT Tarriff) that is reported In Lines 1 - 6, 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.

For BART there is no billing determinate for Scheduling, System Control and Dispatch. The monthly charge is a flat rate.

Schedule Page: 398 Line No.: 7 Column: b

This line includes Ancillary Services as follows:

AS under grandfathered existing contracts (Note A)						
Regulation Service Charge	-	-	-		Flat Charge	0
ISO related AS activities (Note B)						
Retail/BART ISO Purchases and Sales and Existing Transmission Contracts (ETC) (a)	-	Various	12,066,416	-	Various	9,930,932
Total			12,066,416			9,930,932

(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.

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	03/09/2018	End of 2017/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	13,871	25	1900	9,710			78		4,083
2	February	13,519	1	1900	9,526			99		3,894
3	March	12,916	26	1900	9,255			55		3,607
4	Total for Quarter 1				28,491			232		11,584
5	April	12,271	26	2100	7,958			69		4,244
6	May	16,109	22	1900	11,312			102		4,695
7	June	20,435	19	1800	14,614			91		5,730
8	Total for Quarter 2				33,884			262		14,669
9	July	19,073	7	1900	13,785			98		5,190
10	August	20,418	28	1800	14,267			73		6,078
11	September	21,005	1	1800	14,268			96		6,641
12	Total for Quarter 3				42,320			267		17,909
13	October	14,345	24	1900	8,957			98		5,290
14	November	13,485	29	1900	8,240			97		5,148
15	December	13,897	13	1900	8,578			50		5,269
16	Total for Quarter 4				25,775			245		15,707
17	Total Year to Date/Year				130,470			1,006		59,869

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 10 Column: e

Entry was estimated in prior period and is now updated to reflect actuals.

Schedule Page: 400 Line No.: 11 Column: e

Entry was estimated in prior period and is now updated to reflect actuals.

Schedule Page: 400 Line No.: 15 Column: b

The source of the entries in this column is the metered data from Pacific Gas and Electric Company's (the "Utility") Daily Service Report, Line 9.

Schedule Page: 400 Line No.: 15 Column: f

Entries here represent Open Access Transmission Tariff Network Service to the Bay Area Rapid Transit District.

Schedule Page: 400 Line No.: 15 Column: h

Entries here represent transmission service to the following Existing Transmission Contract customers:

City and County of San Francisco (through July 1, 2015)
Transmission Agency of Northern California
Western Area Power Administration ("WAPA")

Schedule Page: 400 Line No.: 15 Column: j

Transmission services utilizing the Utility's transmission system are also sold by the California Independent System Operator ("ISO") to other wholesale entities. The ISO tracks this data and reports it separately to the FERC. The Utility does not have access to this data. The ISO numbers reported in this column were derived by subtracting columns (e)-(i) from column (b).

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	03/09/2018	End of 2017/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	5,275,270
4	Nuclear	17,926,451
5	Hydro-Conventional	10,866,652
6	Hydro-Pumped Storage	872,199
7	Other	735,053
8	Less Energy for Pumping	1,161,566
9	Net Generation (Enter Total of lines 3 through 8)	34,514,059
10	Purchases	34,369,444
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	597,814
17	Delivered	586,191
18	Net Transmission for Other (Line 16 minus line 17)	11,623
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	68,895,126

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	62,117,596
23	Requirements Sales for Resale (See instruction 4, page 311.)	5,661,727
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	1,115,803
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	68,895,126

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	03/09/2018	End of 2017/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: PACIFIC 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	6,758,070		12,229	3	1800
30	February	5,866,859		11,758	1	1900
31	March	6,276,232		11,795	6	2000
32	April	5,984,572		11,194	26	2100
33	May	6,795,293		14,777	22	1900
34	June	7,613,772		18,758	19	1800
35	July	8,432,128		17,647	7	1900
36	August	8,438,228		18,726	28	1800
37	September	7,607,938		19,293	1	1800
38	October	6,639,628		12,666	24	1900
39	November	6,475,440		11,885	29	1900
40	December	6,937,380		12,247	13	1900
41	TOTAL	83,825,540				

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	03/09/2018	2017/Q4

FOOTNOTE DATA

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, photovoltaic, and Fuel Cells.

This includes photovoltaic generation of 297,758 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 20,396,327 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 amount is netted against MWH sales for DWR and DA as discussed in the footnote to Line 10, column b. Including MWH sales for DWR and DA customers reconciles to the amount shown on Page 301, Line 10 column (d).

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.

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	711.50
6	Net Peak Demand on Plant - MW (60 minutes)	2240	657
7	Plant Hours Connected to Load	8760	5797
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	1334	23
12	Net Generation, Exclusive of Plant Use - KWh	17926450684	2496246148
13	Cost of Plant: Land and Land Rights	22726560	7889274
14	Structures and Improvements	1047639381	114976388
15	Equipment Costs	6596318867	540073442
16	Asset Retirement Costs	1646806164	3912558
17	Total Cost	9313490972	666851662
18	Cost per KW of Installed Capacity (line 17/5) Including	4009.2514	937.2476
19	Production Expenses: Oper, Supv, & Engr	6147760	80816
20	Fuel	124868867	56511583
21	Coolants and Water (Nuclear Plants Only)	30611193	0
22	Steam Expenses	38190638	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1998438	3968749
26	Misc Steam (or Nuclear) Power Expenses	162285330	1031521
27	Rents	0	0
28	Allowances	0	11798596
29	Maintenance Supervision and Engineering	3239200	25660
30	Maintenance of Structures	1104975	1902719
31	Maintenance of Boiler (or reactor) Plant	29240710	685185
32	Maintenance of Electric Plant	42948466	4032488
33	Maintenance of Misc Steam (or Nuclear) Plant	57119138	1301921
34	Total Production Expenses	497754715	81339238
35	Expenses per Net KWh	0.0278	0.0326

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MWD					
38	Quantity (Units) of Fuel Burned	2253271	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	55.211	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.674	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.007	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10293.363	0.000	0.000	0.000	0.000	0.000

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0			0
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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	03/09/2018	End of 2017/Q4

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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	03/09/2018	End of 2017/Q4

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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	03/09/2018	End of 2017/Q4

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

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: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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	03/09/2018	End of 2017/Q4

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

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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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	03/09/2018	End of 2017/Q4

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

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

Plant Name: *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
619.70	162.70	0.00	5
580	163	0	6
6721	8729	0	7
0	0	0	8
0	0	0	9
0	0	0	10
24	18	0	11
2779023638	431521194	0	12
5040000	161399	0	13
72348661	67112251	0	14
381397259	149659404	0	15
3004029	1925852	0	16
461789949	218858906	0	17
745.1831	1345.1684	0	18
80816	24795	0	19
62542972	12157864	0	20
0	0	0	21
10249	0	0	22
0	0	0	23
0	0	0	24
3792948	3271682	0	25
1047178	1094234	0	26
0	0	0	27
13262500	2422070	0	28
25660	7872	0	29
272634	188944	0	30
888845	95776	0	31
2962830	4018278	0	32
1218965	0	0	33
86105597	23281515	0	34
0.0310	0.0540	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			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			0			0			21
0			0			0			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
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			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			0			0			21
0			0			0			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
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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.

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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/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. 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	8,208	7,766
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	177,129,078	549,141,575
13	Cost of Plant		
14	Land and Land Rights	8,201	2,690
15	Structures and Improvements	836,168	5,016,476
16	Reservoirs, Dams, and Waterways	9,453,947	6,740,100
17	Equipment Costs	9,783,350	38,788,930
18	Roads, Railroads, and Bridges	1,063,757	1,074,071
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	21,145,423	51,622,267
21	Cost per KW of Installed Capacity (line 20 / 5)	682.1104	531.0933
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	7,218	20,012
25	Hydraulic Expenses	47,754	146,318
26	Electric Expenses	207,843	566,074
27	Misc Hydraulic Power Generation Expenses	141,407	436,266
28	Rents	8,441	26,044
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	157,378	493,766
31	Maintenance of Reservoirs, Dams, and Waterways	164,864	565,951
32	Maintenance of Electric Plant	207,153	675,607
33	Maintenance of Misc Hydraulic Plant	45,110	199,393
34	Total Production Expenses (total 23 thru 33)	987,168	3,129,431
35	Expenses per net KWh	0.0056	0.0057

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/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. 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	7,682	8,313
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	135,256,510	323,564,921
13	Cost of Plant		
14	Land and Land Rights	407,592	301,143
15	Structures and Improvements	3,157,541	5,278,847
16	Reservoirs, Dams, and Waterways	36,557,802	28,133,994
17	Equipment Costs	15,459,006	25,553,031
18	Roads, Railroads, and Bridges	613,644	775,813
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	56,195,585	60,042,828
21	Cost per KW of Installed Capacity (line 20 / 5)	1,404.8896	813.0376
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	17,874	20,557
25	Hydraulic Expenses	16,234	22,665
26	Electric Expenses	345,529	290,184
27	Misc Hydraulic Power Generation Expenses	270,996	467,993
28	Rents	1,919	3,501
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	52,300	171,135
31	Maintenance of Reservoirs, Dams, and Waterways	534,531	1,500,667
32	Maintenance of Electric Plant	213,601	367,417
33	Maintenance of Misc Hydraulic Plant	139,787	243,014
34	Total Production Expenses (total 23 thru 33)	1,592,771	3,087,133
35	Expenses per net KWh	0.0118	0.0095

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	03/09/2018	End of 2017/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. 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	3,650	4,641
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	27,707,675	129,801,413
13	Cost of Plant		
14	Land and Land Rights	147,231	1,456,780
15	Structures and Improvements	3,154,823	5,265,695
16	Reservoirs, Dams, and Waterways	41,907,179	36,710,876
17	Equipment Costs	6,128,893	18,753,492
18	Roads, Railroads, and Bridges	2,520,431	1,387,881
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	53,858,557	63,574,724
21	Cost per KW of Installed Capacity (line 20 / 5)	2,919.1630	1,292.1692
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	5,575	12,772
25	Hydraulic Expenses	37,453	7
26	Electric Expenses	253,316	469,343
27	Misc Hydraulic Power Generation Expenses	402,868	409,198
28	Rents	2,547	22,957
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	93,418	38,684
31	Maintenance of Reservoirs, Dams, and Waterways	1,169,967	544,876
32	Maintenance of Electric Plant	91,498	628,029
33	Maintenance of Misc Hydraulic Plant	55,256	53,884
34	Total Production Expenses (total 23 thru 33)	2,111,898	2,179,750
35	Expenses per net KWh	0.0762	0.0168

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	03/09/2018	End of 2017/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. 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	8,743	6,017
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	759,659,380	31,485,116
13	Cost of Plant		
14	Land and Land Rights	28,475	1,007,431
15	Structures and Improvements	10,857,648	2,875,538
16	Reservoirs, Dams, and Waterways	28,694,285	27,097,465
17	Equipment Costs	30,629,262	7,994,592
18	Roads, Railroads, and Bridges	755,490	262,880
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	70,965,160	39,237,906
21	Cost per KW of Installed Capacity (line 20 / 5)	525.6679	2,885.1401
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	26,915	2,974
25	Hydraulic Expenses	200,665	0
26	Electric Expenses	689,940	405,956
27	Misc Hydraulic Power Generation Expenses	698,731	143,608
28	Rents	147,636	5,346
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	122,127	16,283
31	Maintenance of Reservoirs, Dams, and Waterways	524,654	278,136
32	Maintenance of Electric Plant	556,115	476,123
33	Maintenance of Misc Hydraulic Plant	128,136	11,371
34	Total Production Expenses (total 23 thru 33)	3,094,919	1,339,797
35	Expenses per net KWh	0.0041	0.0426

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	03/09/2018	End of 2017/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. 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	7,751	7,058
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	794,723,257	223,088,700
13	Cost of Plant		
14	Land and Land Rights	584,693	17,498
15	Structures and Improvements	39,036,766	5,517,020
16	Reservoirs, Dams, and Waterways	89,093,667	21,064,800
17	Equipment Costs	49,789,361	13,898,923
18	Roads, Railroads, and Bridges	7,534,863	396,618
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	186,039,350	40,894,859
21	Cost per KW of Installed Capacity (line 20 / 5)	1,333.6154	841.4580
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	282,288	10,404
25	Hydraulic Expenses	0	72,462
26	Electric Expenses	99,722	236,622
27	Misc Hydraulic Power Generation Expenses	589,980	245,437
28	Rents	22,155	53,324
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	31,449	19,271
31	Maintenance of Reservoirs, Dams, and Waterways	101,046	193,040
32	Maintenance of Electric Plant	306,808	459,808
33	Maintenance of Misc Hydraulic Plant	445,824	25,541
34	Total Production Expenses (total 23 thru 33)	1,879,272	1,315,909
35	Expenses per net KWh	0.0024	0.0059

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	03/09/2018	End of 2017/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. 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	6,121	8,689
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	240,936,228	375,432,679
13	Cost of Plant		
14	Land and Land Rights	3,817,108	333,064
15	Structures and Improvements	8,072,333	4,356,232
16	Reservoirs, Dams, and Waterways	68,607,059	40,748,177
17	Equipment Costs	29,096,997	37,114,754
18	Roads, Railroads, and Bridges	7,454,725	4,167,132
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	117,048,222	86,719,359
21	Cost per KW of Installed Capacity (line 20 / 5)	1,459.6361	837.8682
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	45,004	52,541
25	Hydraulic Expenses	12,029	13,084
26	Electric Expenses	419,992	274,971
27	Misc Hydraulic Power Generation Expenses	1,039,021	1,057,550
28	Rents	5,240	5,240
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	49,396	3,255
31	Maintenance of Reservoirs, Dams, and Waterways	-33,535	65,833
32	Maintenance of Electric Plant	344,871	347,495
33	Maintenance of Misc Hydraulic Plant	116,556	74,998
34	Total Production Expenses (total 23 thru 33)	1,998,574	1,894,967
35	Expenses per net KWh	0.0083	0.0050

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/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)
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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	8,217	7,435
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	611,744,271	551,002,622
13	Cost of Plant		
14	Land and Land Rights	821,203	1,777,826
15	Structures and Improvements	3,952,710	20,970,369
16	Reservoirs, Dams, and Waterways	54,408,021	44,723,983
17	Equipment Costs	37,991,169	106,329,268
18	Roads, Railroads, and Bridges	1,625,737	353,339
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	98,798,840	174,154,785
21	Cost per KW of Installed Capacity (line 20 / 5)	691.7233	1,389.1265
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	24,108	24,582
25	Hydraulic Expenses	31,176	32,311
26	Electric Expenses	521,074	1,238,517
27	Misc Hydraulic Power Generation Expenses	554,145	1,293,242
28	Rents	8,894	10,292
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	42,724	105,275
31	Maintenance of Reservoirs, Dams, and Waterways	111,595	1,385,277
32	Maintenance of Electric Plant	2,076,581	287,755
33	Maintenance of Misc Hydraulic Plant	397,744	39,856
34	Total Production Expenses (total 23 thru 33)	3,768,041	4,417,107
35	Expenses per net KWh	0.0062	0.0080

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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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	7,294	7,554
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	87,946,038	59,105,999
13	Cost of Plant		
14	Land and Land Rights	155,108	852,893
15	Structures and Improvements	868,385	4,130,045
16	Reservoirs, Dams, and Waterways	5,701,171	17,512,245
17	Equipment Costs	7,407,107	10,684,809
18	Roads, Railroads, and Bridges	288,661	226,388
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	14,420,432	33,406,380
21	Cost per KW of Installed Capacity (line 20 / 5)	1,060.3259	2,456.3515
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	7,099	3,658
25	Hydraulic Expenses	5,828	3,036
26	Electric Expenses	252,303	754,808
27	Misc Hydraulic Power Generation Expenses	218,032	162,143
28	Rents	8,813	6,574
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	39,763	18,508
31	Maintenance of Reservoirs, Dams, and Waterways	218,989	303,444
32	Maintenance of Electric Plant	101,397	96,662
33	Maintenance of Misc Hydraulic Plant	24,566	17,766
34	Total Production Expenses (total 23 thru 33)	876,790	1,366,599
35	Expenses per net KWh	0.0100	0.0231

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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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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	03/09/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 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
5,242	8,729	7,564	7
			8
125	172	65	9
125	172	53	10
0	0	0	11
286,113,882	769,490,580	264,461,909	12
			13
664,014	604,257	810,631	14
11,581,136	770,527	1,360,755	15
58,322,007	66,784,287	21,125,486	16
59,329,425	17,988,909	22,346,102	17
479,487	2,073,234	3,085,588	18
0	0	0	19
130,376,069	88,221,214	48,728,562	20
1,105.8191	523.0714	738.3115	21
			22
0	0	0	23
24,503	58,983	37,361	24
32,122	16,332	23,569	25
203,870	424,936	373,977	26
758,607	729,668	614,427	27
5,827	11,001	20,796	28
0	0	0	29
71,615	10,519	28,189	30
629,099	145,919	162,024	31
685,861	604,612	243,539	32
256,814	99,697	75,344	33
2,668,318	2,101,667	1,579,226	34
0.0093	0.0027	0.0060	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. 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
6,849	8,154	8,205	7
			8
120	13	70	9
119	5	72	10
0	0	0	11
467,053,778	59,047,171	367,271,089	12
			13
376,506	183,656	1,364,666	14
10,224,928	1,705,759	4,956,754	15
35,123,248	23,728,380	21,065,002	16
29,654,671	13,265,669	11,446,004	17
16,677	1,869,994	135,058	18
0	0	0	19
75,396,030	40,753,458	38,967,484	20
639.4913	3,354.1941	528.0147	21
			22
0	0	0	23
24,108	734	20,163	24
31,176	16,404	21,719	25
293,819	193,538	169,853	26
728,725	52,112	737,091	27
5,594	380	5,718	28
0	0	0	29
106,507	19,763	30,766	30
125,099	225,140	135,185	31
213,507	182,916	341,393	32
35,287	17,921	27,164	33
1,563,822	708,908	1,489,052	34
0.0033	0.0120	0.0041	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. 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
7,918	7,670	7,837	7
			8
50	22	98	9
49	23	98	10
0	0	0	11
311,112,744	77,204,405	445,975,925	12
			13
462,337	761,776	751,637	14
1,166,618	2,041,094	1,990,351	15
11,884,990	18,376,553	26,653,813	16
8,197,469	14,244,102	24,587,389	17
488,550	393,427	1,425,094	18
0	0	0	19
22,199,964	35,816,952	55,408,284	20
418.0784	1,628.0433	540.5686	21
			22
0	0	0	23
11,747	5,481	146,408	24
711	359	14,689	25
515,176	386,939	724,374	26
381,396	211,497	927,130	27
21,114	9,851	45,339	28
0	0	0	29
36,553	24,446	173,440	30
384,086	257,673	868,797	31
144,741	86,092	427,050	32
52,176	41,741	125,633	33
1,547,700	1,024,079	3,452,860	34
0.0050	0.0133	0.0077	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
8,449	8,511	4,004	7
			8
9	9	25	9
4	9	0	10
0	0	0	11
34,503,424	41,704,608	73,231,753	12
			13
710,378	781,162	7,422	14
247,399	286,003	1,655,807	15
2,773,743	1,868,176	3,341,709	16
2,782,697	3,619,072	6,676,377	17
1,168,538	400,578	6,487	18
0	0	0	19
7,682,755	6,954,991	11,687,802	20
768.2755	695.4991	514.4279	21
			22
0	0	0	23
0	0	47,117	24
359	359	0	25
141,049	128,605	122,432	26
142,899	142,899	70,229	27
75	75	3,634	28
0	0	0	29
4,413	1,554	15,267	30
13,794	81,311	41,784	31
44,262	73,228	162,655	32
47,848	13,716	73,059	33
394,699	441,747	536,177	34
0.0114	0.0106	0.0073	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. 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
5,672	4,394	8,440	7
			8
12	12	61	9
12	0	61	10
0	0	0	11
61,397,332	14,168,184	295,248,991	12
			13
274,356	2,124,886	2,315,448	14
1,172,743	6,650,378	2,246,644	15
1,193,545	48,031,464	12,994,543	16
5,777,012	8,324,548	30,755,825	17
506,629	3,010,692	1,448,431	18
0	0	0	19
8,924,285	68,141,968	49,760,891	20
874.9299	5,365.5093	718.0504	21
			22
0	0	0	23
155,594	3,088	87,069	24
0	0	11,649	25
77,615	340,194	233,655	26
327,879	146,697	943,875	27
0	5,550	0	28
0	0	0	29
18,398	16,590	5,118	30
145,547	282,664	130,395	31
113,561	109,449	202,055	32
851	24,409	131,735	33
839,445	928,641	1,745,551	34
0.0137	0.0655	0.0059	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. 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	8,351	8,270	7
			8
160	80	112	9
160	80	112	10
0	0	0	11
227,197,238	324,181,470	462,524,778	12
			13
641,138	361,016	313,713	14
19,932,352	3,173,264	2,724,271	15
42,288,675	32,870,527	31,371,592	16
72,613,481	13,306,522	11,514,970	17
8,871,783	686,970	405,830	18
0	0	0	19
144,347,429	50,398,299	46,330,376	20
1,017.6779	636.3422	421.9524	21
			22
0	0	0	23
0	58,983	58,983	24
15,826	12,451	13,801	25
546,242	361,575	333,852	26
1,116,490	726,908	755,925	27
5,240	11,001	11,001	28
0	0	0	29
2,355,289	26,958	4,206	30
2,899,798	68,898	221,242	31
304,658	333,715	119,429	32
636,174	63,997	74,573	33
7,879,717	1,664,486	1,593,012	34
0.0347	0.0051	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	03/09/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 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
8,608	7,638	5,738	7
			8
44	91	58	9
34	91	58	10
0	0	0	11
226,235,015	426,898,660	192,631,242	12
			13
227,032	419,286	2,546,253	14
1,922,806	1,139,628	6,862,673	15
31,756,503	36,549,656	51,732,100	16
12,602,069	25,632,418	16,281,824	17
1,515,912	1,145,370	7,568,872	18
0	0	0	19
48,024,322	64,886,358	84,991,722	20
1,142.6201	792.2632	1,625.7024	21
			22
0	0	0	23
19,485	338,286	22,429	24
11,221	14,675	11,738	25
444,659	562,240	545,141	26
563,446	2,287,456	587,442	27
24,187	41,655	27,841	28
0	0	0	29
104,081	17,611	125,328	30
1,213,036	709,478	897,110	31
234,680	499,088	357,585	32
71,307	302,909	145,779	33
2,686,102	4,773,398	2,720,393	34
0.0119	0.0112	0.0141	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	03/09/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 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
3,861	0	0	7
			8
20	0	0	9
12	0	0	10
0	0	0	11
34,925,931	0	0	12
			13
983,573	0	0	14
1,477,138	0	0	15
53,183,533	0	0	16
6,146,829	0	0	17
29,392	0	0	18
0	0	0	19
61,820,465	0	0	20
4,829.7238	0.0000	0.0000	21
			22
0	0	0	23
29,621	0	0	24
0	0	0	25
105,821	0	0	26
602,838	0	0	27
37,638	0	0	28
0	0	0	29
13,532	0	0	30
29,912	0	0	31
241,835	0	0	32
4	0	0	33
1,061,201	0	0	34
0.0304	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	03/09/2018	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 406 Line No.: 11 Column: b

Schedule Page: 406 Line No.: 11 Column: b

Average Number of Employees on pages 406 and 407 line 11 left blank due to remote operation and remote area headquarters. Refer to the table below for further details on operations and maintenance staffing for each plant. Many of these plants are attended by roving operators as well additional support staff.

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	7	Burney Service Center	42
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	6		
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	9
BUTT VALLEY	Y			Caribou Switching Center	10	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	8	Auburn SC Service Center	24
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	21
HAAS	Y	Fresno Operating Center	5	Balch Camp	10	Auberry Service Center	22
BALCH NO. 1	Y						
BALCH NO. 2	Y						
KINGS RIVER	Y						
KERCKHOFF NO. 1	Y			Auberry Service Center	11		
KERCKHOFF	Y						

FOOTNOTE DATA

NO. 2	
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	03/09/2018	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 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	2,583
7	Net Plant Capability (in megawatts)	1,212
8	Average Number of Employees	21
9	Generation, Exclusive of Plant Use - Kwh	872,198,855
10	Energy Used for Pumping	1,161,566,490
11	Net Output for Load (line 9 - line 10) - Kwh	-289,367,635
12	Cost of Plant	
13	Land and Land Rights	752,733
14	Structures and Improvements	184,548,512
15	Reservoirs, Dams, and Waterways	446,220,926
16	Water Wheels, Turbines, and Generators	270,958,952
17	Accessory Electric Equipment	60,006,668
18	Miscellaneous Powerplant Equipment	24,553,533
19	Roads, Railroads, and Bridges	8,773,225
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	995,814,549
22	Cost per KW of installed cap (line 21 / 4)	945.6928
23	Production Expenses	
24	Operation Supervision and Engineering	15,098
25	Water for Power	303,982
26	Pumped Storage Expenses	2,218
27	Electric Expenses	1,860,596
28	Misc Pumped Storage Power generation Expenses	1,997,893
29	Rents	43,681
30	Maintenance Supervision and Engineering	35,717
31	Maintenance of Structures	459,229
32	Maintenance of Reservoirs, Dams, and Waterways	640,773
33	Maintenance of Electric Plant	2,862,429
34	Maintenance of Misc Pumped Storage Plant	2,167,088
35	Production Exp Before Pumping Exp (24 thru 34)	10,388,704
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	10,388,704
38	Expenses per KWh (line 37 / 9)	0.0119

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	03/09/2018	End of 2017/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	3,477	13,580,347
3	Centerville FERC No.803	1904	6.40	6.4		17,539,385
4	Chili Bar FERC No.2155	1965	7.02	7.0	43,389	16,674,130
5	Coal Canyon	1907				2,943,460
6	Cow Creek FERC No.606	1907	1.44	1.8	7,639	3,210,404
7	Crane Valley FERC No.1354	1919	0.99	0.9	3,302	18,948,641
8	Deer Creek FERC No.2310	1908	5.50	5.7	13,751	87,496,137
9	Hamilton Branch	1921	5.39	4.8	7,870	8,402,315
10	Inskip FERC No.1121	1979	7.65	8.0	10,739	19,913,595
11	Kern Canyon FERC No. 178	1921	9.54	11.5	299	12,751,526
12	Kilarc FERC No.606	1904	3.00	3.2	8,930	4,326,679
13	Lime Saddle	1906	2.00	2.0	5,140	17,214,532
14	Merced Falls FERC No.2467	1930	3.44	3.5	-10	7,678
15	Oak Flat FERC No.2105	1985	1.40	1.3	4	8,812,160
16	Phoenix FERC No.1061	1940	1.60	2.0	6,459	14,737,495
17	Potter Valley FERC No.77	1910	9.46	9.2	19,430	47,815,466
18	San Joaquin No. 1-A FERC No.1354	1919	0.42	0.4		32,761,318
19	San Joaquin No. 2 FERC No.1354	1917	2.88	3.2	6,723	31,741,452
20	San Joaquin No. 3 FERC No.1354	1923	4.00	4.2	1,156	28,601,493
21	South FERC No.1121	1979	6.75	7.0	14,139	16,966,302
22	Spaulding No. 1 FERC No.2310	1928	7.04	7.0	43	41,293,314
23	Spaulding No. 2 FERC No.2310	1928	3.70	4.4	4,465	16,106,144
24	Spaulding No. 3 FERC No.2310	1929	6.61	5.8	31,338	14,962,603
25	Spring Gap FERC No.2130	1921	6.00	7.0	29,680	11,202,913
26	Toadtown FERC No.803	1986	1.80	1.5	3,268	7,290,745
27	Tule FERC No.1333	1914	4.50	6.4	-2,447	15,119,899
28	Volta No.1 FERC No.1121	1980	8.55	9.0	54,337	17,525,762
29	Volta No.2 FERC No.1121	1981	0.95	0.9	6	3,096,726
30	Wise II FERC No.2310	1986	2.87	3.2	-33	13,298,357
31	Miscellaneous Minor					11,709,314
32						
33	Photo Voltaic Generating Plants:					
34	AT&T PARK SOLAR ARRAYS	2007	0.11	0.1	140	1,990,928
35	SF SERVICE CENTER SOLAR ARRAY 1 & 2	2007	0.18	0.2	114	72,959
36	Vaca Dixon Solar Station	2009	2.00	2.0	3,434	10,881,965
37	Five Points - Schindler Solar Station #1	2011	15.00	15.0	27,708	54,611,878
38	Westside - Schindler Solar Station #2	2011	15.00	15.0	25,383	48,125,236
39	Stroud Solar Station	2011	20.00	20.0	34,562	61,796,680
40	Cantua Solar Station	2012	20.00	20.0	39,822	56,336,699
41	Giffen Solar Station	2012	10.00	10.0	18,175	31,406,643
42	Huron Solar Station	2012	20.00	20.0	40,413	61,111,111
43	Gates Solar Station	2013	20.00	20.0	42,378	65,636,729
44	West Gates Solar Station	2013	10.00	10.0	21,555	77,116,304
45	Guernsey Solar Station	2013	20.00	20.0	44,076	35,769,160
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	03/09/2018	End of 2017/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	Fuel Cell:					
2	San Francisco State	2011	1.60	1.6	1,574	8,504,503
3	California State University East Bay	2011	1.40	1.4	4,199	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	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	03/09/2018	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
13,580,347	370,811		304,104	Water		2
2,740,529	270,077		326,887	Water		3
2,375,232	336,010		346,024	Water		4
	93,003		291,438	Water		5
2,229,447	133,189		241,651	Water		6
19,140,041	77,222		174,786	Water		7
15,908,389	212,365		834,624	Water		8
1,558,871	374,086		189,160	Water		9
2,603,084	266,098		382,702	Water		10
1,336,638	243,266		273,986	Water		11
1,442,226	169,973		299,429	Water		12
6,252,102	321,686		611,011	Water		13
2,232	38,029		55,570	Water		14
6,294,400	267,070		88,792	Water		15
9,210,934	346,005		436,088	Water		16
5,054,489	2,083,261		1,044,681	Water		17
78,003,139	56,218		227,328	Water		18
11,021,337	183,481		119,200	Water		19
7,150,373	169,250		83,708	Water		20
2,513,526	268,634		919,447	Water		21
5,865,528	436,606		361,767	Water		22
4,353,012	408,118		278,435	Water		23
2,263,631	464,383		369,241	Water		24
1,867,152	397,765		440,693	Water		25
4,050,414	225,322		223,186	Water		26
3,359,978	205,164		375,237	Water		27
2,049,797	455,783		1,288,448	Water		28
3,259,712	241,648		79,722	Water		29
4,633,574	371,940		281,385	Water		30
				Water		31
						32
						33
17,936,287			45,670	Solar		34
405,327			15,447	Solar		35
5,440,983	26,513		20,139	Solar		36
3,640,792	63,970		99,497	Solar		37
3,208,349	93,481		493,618	Solar		38
3,089,834	96,234		424,723	Solar		39
2,816,835	63,177		100,376	Solar		40
3,140,664	46,689		76,516	Solar		41
3,055,556	66,213		59,589	Solar		42
3,281,836	29,503		67,761	Solar		43
7,711,630	16,824		25,194	Solar		44
1,788,458	79,946		196,790	Solar		45
						46

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	325,740	67,919	502,766	Natural Gas	470	2
4,701,886	247,375	233,887	382,059	Natural Gas	483	3
						4
						5
						6
				Diesel		7
				Diesel		8
				Diesel		9
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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	03/09/2018	2017/Q4

FOOTNOTE DATA

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (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	SSP T	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	OTHER T	46.90		1
10	MIDWAY	WHIRLWIND	500.00	500.00	T	52.77		1
11	MOSS LANDING	LOS BANOS	500.00	500.00	SSP T	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	SSP T	89.03		1
14	ROUND MTN	TABLE MTN #2	500.00	500.00	SSP T	89.02		1
15	TABLE MTN	TESLA	500.00	500.00	OTHER T	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	SSP T	1.13		1
20	TRACY	LOS BANOS	500.00	500.00	SSP SSP T	56.23		1
21	VACA	TESLA	500.00	500.00	T	57.00		1
22	ARCO	MIDWAY	230.00	230.00	SSP SWP T	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	SSP T	6.67		1
26	BAKERSFIELD #2 TAP		230.00	230.00	SSP T	7.01		1
27	BALCH	MCCALL	230.00	230.00	SSP T	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 T	37.94		1
31	BELLOTA	WARNERVILLE	230.00	230.00	SSP T	22.47		1
32	BELLOTA	WEBER	230.00	230.00	SSP T	14.26		1
33	BIRDS LANDING SW STA	SHILOH	230.00	230.00	SSP SWP	0.11		1
34	BIRDS LANDING SW STA	CONTRA COSTA PP	230.00	230.00	SSP T	10.20		1
35	BIRDS LANDING SW STA	CONTRA COSTA SUB	230.00	230.00	SSP T	9.46		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (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	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 T	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	SSP T	16.41		1
6	BRIGHTON	BELLOTA	230.00	230.00	T	42.51		1
7	BUCKS CREEK	ROCK CREEK-CRESTA	230.00	230.00	SSP T	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	SSP T	27.17		1
12	CALIENTE SW STA	MIDWAY #2	230.00	230.00	SSP T	27.16		1
13	CALIFORNIA FLATS SW STA	GATES	230.00	230.00	OTHER SSP	22.57		1
14	CAMANCHE PUMPING		230.00	230.00	SSP T	0.45		1
15	CARBERRY SW STA	ROUND MTN	230.00	230.00	SSP T	12.61		1
16	CARIBOU	TABLE MTN	230.00	230.00	OTHER 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	SSP T	63.97		1
19	COLGATE	RIO OSO	230.00	230.00	T	40.89		1
20	CONTRA COSTA	BRENTWOOD	230.00	230.00	SSP T	10.06		1
21	CONTRA COSTA	DELTA SWITCHYARD	230.00	230.00	SSP T	18.46		1
22	CONTRA COSTA	LAS POSITAS	230.00	230.00	SSP T	23.83		1
23	CONTRA COSTA	LONE TREE	230.00	230.00	SSP T	5.62		1
24	CONTRA COSTA	MORAGA #1	230.00	230.00	SSP T	26.76		1
25	CONTRA COSTA	MORAGA #2	230.00	230.00	SSP T	26.84		1
26	CONTRA COSTA PP	CONTRA COSTA SUB	230.00	230.00	SSP T	1.89		1
27	CORTINA	VACA	230.00	230.00	T	53.29		1
28	COTTLE	MELONES	230.00	230.00	SSP T	25.94		1
29	COTTONWOOD	DELEVAN #1	230.00	230.00	T	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 T	0.11		1
34	COYOTE SW STA	METCALF	230.00	230.00	T	0.88		1
35	CRESTA	RIO OSO	230.00	230.00	SSP T	64.77		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	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	SSP T	23.68		1
9	EASTSHORE	SAN MATEO	230.00	230.00	SSP OTHER	12.43		1
10	EIGHT MILE ROAD	TESLA	230.00	230.00	SSP OTHER	26.64		1
11	EIGHT MILE ROAD	STAGG	230.00	230.00	SSP T	7.19		1
12	ELECTRA	BELLOTA	230.00	230.00	SSP T	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	T	15.84		1
16	FULTON	IGNACIO #1	230.00	230.00	SSP T	40.73		1
17	FULTON	LAKEVILLE	230.00	230.00	N/A	1.19		1
18	GATES	MUSTANG SW STA #1	230.00	230.00	SSP T	13.17		1
19	GATES	MUSTANG SW STA #2	230.00	230.00	SSP T	13.18		1
20	GATES	ARCO	230.00	230.00	T	35.18		1
21	GATES	GREGG	230.00	230.00	SSP T SSP	0.07		1
22	GATES	PANOCHE #1	230.00	230.00	SSP T	43.79		1
23	GATES	PANOCHE #2	230.00	230.00	SSP T	43.80		1
24	GATES	MIDWAY	230.00	230.00	SSP T	63.86		1
25	GEYSERS #12	FULTON	230.00	230.00	OTHER 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	SSP T	26.14		1
29	GEYSERS #18 TAP		230.00	230.00	SWP T	0.75		1
30	GEYSERS #20 TAP		230.00	230.00	T	0.03		1
31	GEYSERS #9	LAKEVILLE	230.00	230.00	T	41.71		1
32	GLENN	DELEVAN	230.00	230.00	SSP T	37.42		1
33	GOLD HILL	EIGHT MILE ROAD	230.00	230.00	SSP T	48.80		1
34	GOLD HILL	LODI STIG	230.00	230.00	T	46.67		1
35	GREGG	ASHLAN	230.00	230.00	SSP OTHER	7.00		1
36					TOTAL	36,892.15		1,445

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	GREGG	HERNDON #1	230.00	230.00	T	0.60		1
2	GREGG	HERNDON #2	230.00	230.00	T	0.63		1
3	H	Z #1	230.00	230.00	N/A	6.92		1
4	H	Z #2	230.00	230.00	N/A	6.96		1
5	HAAS	MCCALL	230.00	230.00	SSP T	44.21		1
6	HELM	MCCALL	230.00	230.00	T	30.84		1
7	HELMS	GREGG #1	230.00	230.00	T	60.67		1
8	HELMS	GREGG #2	230.00	230.00	T	60.68		1
9	HERNDON	ASHLAN	230.00	230.00	SSP OTHER	6.39		1
10	HERNDON	KEARNEY	230.00	230.00	T	10.81		1
11	HICKS	METCALF	230.00	230.00	SSP T	9.07		1
12	IGNACIO	SOBRANTE	230.00	230.00	SSP SSP T	42.49		1
13	JEFFERSON	MARTIN	230.00	230.00	SSP	3.46		1
14	JEFFERSON	MARTIN	230.00	230.00	N/A	24.26		1
15	KELSO	TESLA	230.00	230.00	SSP T	7.95		1
16	LAKEVILLE	IGNACIO #2	230.00	230.00	T	14.53		1
17	LAKEVILLE	IGNACIO #1	230.00	230.00	SSP SSP T	15.49		1
18	LAKEVILLE	SOBRANTE #2	230.00	230.00	SSP T	47.89		1
19	LAKEVILLE	TULUCAY	230.00	230.00	OTHER SSP	17.22		1
20	LAKEVILLE	TULUCAY	230.00	230.00	OTHER SSP	0.06		1
21	LAMBIE SW STA	BIRDS LANDING SW STA	230.00	230.00	T	7.04		1
22	LAS AGUILAS SW STA	PANOCHE #2	230.00	230.00	SSP T	17.44		1
23	LAS AGUILAS SW STA	PANOCHE #1	230.00	230.00	SSP T	17.44		1
24	LAS POSITAS	NEWARK	230.00	230.00	SSP T	20.93		1
25	LOCKEFORD	BELLOTA	230.00	230.00	T	12.32		1
26	LODI STIG	EIGHT MILE ROAD	230.00	230.00	SSP T	2.18		1
27	LOGAN CREEK	DELEVAN	230.00	230.00	T	12.35		1
28	LONE TREE	CAYETANO	230.00	230.00	T	15.40		1
29	LONE TREE	CAYETANO	230.00	230.00	N/A	2.30		1
30	LOS BANOS	DOS AMIGOS	230.00	230.00	SWP T	14.31		1
31	LOS BANOS	PANOCHE #1	230.00	230.00	T	37.18		1
32	LOS BANOS	PANOCHE #2	230.00	230.00	SSP SWP T	37.13		1
33	LOS BANOS	SAN LUIS PUMPS #1	230.00	230.00	T	3.43		1
34	LOS BANOS	SAN LUIS PUMPS #2	230.00	230.00	T	3.43		1
35	LOS BANOS	QUINTO SW STA	230.00	230.00	T	12.06		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/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	LOS ESTEROS	METCALF	230.00	230.00	SSP T	63.25		1
2	LOS ESTEROS	METCALF	230.00	230.00	N/A	2.73		1
3	MALACHA TAP		230.00	230.00	T	0.12		1
4	MELONES	WILSON	230.00	230.00	SSP T	61.61		1
5	METCALF	MONTA VISTA #3	230.00	230.00	T	28.59		1
6	METCALF	MOSS LANDING #1	230.00	230.00	SSP T	35.76		1
7	METCALF	MOSS LANDING #2	230.00	230.00	SSP T	35.76		1
8	MIDDLE FORK	GOLD HILL	230.00	230.00	OTHER SSP	44.08		1
9	MIDWAY	KERN #1	230.00	230.00	SSP T	41.75		1
10	MIDWAY	KERN #3	230.00	230.00	T	20.88		1
11	MIDWAY	KERN #4	230.00	230.00	SSP T	20.84		1
12	MIDWAY	WHEELER RIDGE #1	230.00	230.00	T	52.68		1
13	MIDWAY	SUNSET	230.00	230.00	T	0.57		1
14	MIDWAY	WHEELER RIDGE #2	230.00	230.00	T	52.65		1
15	MONTA VISTA	COYOTE SW STA	230.00	230.00	T	27.83		1
16	MONTA VISTA	HICKS	230.00	230.00	SSP T	13.27		1
17	MONTA VISTA	JEFFERSON #1	230.00	230.00	SSP T	19.72		1
18	MONTA VISTA	JEFFERSON #2	230.00	230.00	SSP T	19.73		1
19	MONTA VISTA	SARATOGA	230.00	230.00	SSP T	5.49		1
20	MONTEZUMA SW STA	BIRDS LANDING SW STA	230.00	230.00	OTHER SSP	0.54		1
21	MORAGA	CASTRO VALLEY	230.00	230.00	T	14.92		1
22	MORRO BAY	DIABLO	230.00	230.00	T	15.78		1
23	MORRO BAY	CALIFORNIA FLATS SW STA	230.00	230.00	OTHER SSP	46.19		1
24	MORRO BAY	MESA	230.00	230.00	T	35.27		1
25	MORRO BAY	SOLAR SW STA #1	230.00	230.00	T	45.55		1
26	MORRO BAY	SOLAR SW STA #2	230.00	230.00	T	45.56		1
27	MORRO BAY	TEMPLETON	230.00	230.00	SSP T	16.43		1
28	MOSS LANDING	COBURN	230.00	230.00	SSP SWP T	64.03		1
29	MOSS LANDING	LAS AGUILAS SW STA	230.00	230.00	SSP T	51.89		1
30	MOSS LANDING		230.00	230.00	T	0.13		1
31	MOSS LANDING TX BK 1	230 SWITCHYARD	230.00	230.00	SWP OTHER	0.24		1
32	MOSS LANDING TX BK 2	230 SWITCHYARD	230.00	230.00	T	0.16		1
33	MUSTANG SW STA	GREGG	230.00	230.00	SSP T SSP	45.40		1
34	MUSTANG SW STA	MCCALL	230.00	230.00	SSP SSP T	42.11		1
35	NEWARK	LOS ESTEROS	230.00	230.00	SSP T	5.65		1
36					TOTAL	36,892.15		1,445

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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	NEWARK	RAVENSWOOD	230.00	230.00	T	8.91		1
2	NEWARK	LOS ESTEROS	230.00	230.00	N/A	2.75		1
3	NEWARK E	F BUS TIE	230.00	230.00	T	0.22		1
4	NORTH DUBLIN	CAYETANO	230.00	230.00	T	3.02		1
5	NORTH DUBLIN	VINEYARD	230.00	230.00	T	12.46		1
6	NORTH DUBLIN	CAYETANO	230.00	230.00	N/A	2.81		1
7	NORTH DUBLIN	VINEYARD	230.00	230.00	N/A	11.07		1
8	PALERMO	COLGATE	230.00	230.00	T T	29.60		1
9	PANOCHE	PANOCHE ENERGY	230.00	230.00	SSP	0.09		1
10	PANOCHE	TRANQUILLITY SW STA #1	230.00	230.00	SSP T	12.14		1
11	PANOCHE	TRANQUILLITY SW STA #2	230.00	230.00	SSP T	12.14		1
12	PARKWAY	MORAGA	230.00	230.00	T	23.64		1
13	PEABODY	BIRDS LANDING SW STA	230.00	230.00	SSP SWP T	19.85		1
14	PIT #1	COTTONWOOD	230.00	230.00	OTHER SSP	59.75		1
15	PIT #3	PIT #1	230.00	230.00	OTHER SSP	22.69		1
16	PIT #3	CARBERRY SW STA	230.00	230.00	SSP T	10.91		1
17	PIT #4 TAP		230.00	230.00	SSP T	7.03		1
18	PIT #5	ROUND MTN #1	230.00	230.00	OTHER SWP	13.12		1
19	PIT #5	ROUND MTN #2	230.00	230.00	OTHER SSP	13.11		1
20	PIT #6 JCT	ROUND MTN	230.00	230.00	OTHER SSP	8.15		1
21	PIT #6 TAP		230.00	230.00	SWP T	3.43		1
22	PIT #7 TAP		230.00	230.00	SWP T	3.59		1
23	PITTSBURG	EASTSHORE	230.00	230.00	SSP SWP T	34.92		1
24	PITTSBURG	SAN MATEO	230.00	230.00	SSP SWP	47.40		1
25	PITTSBURG	TASSAJARA	230.00	230.00	SSP T	17.36		1
26	PITTSBURG	SAN RAMON	230.00	230.00	SSP SWP T	21.66		1
27	PITTSBURG	TESORO	230.00	230.00	T	11.27		1
28	PITTSBURG	TESLA #1	230.00	230.00	SSP T	31.35		1
29	PITTSBURG	TESLA #2	230.00	230.00	SSP SWP T	31.32		1
30	PITTSBURG	TIDEWATER	230.00	230.00	T	11.27		1
31	POE	RIO OSO	230.00	230.00	OTHER SSP	56.09		1
32	QUINTO SW STA	WESTLEY	230.00	230.00	T	57.55		1
33	RALPH TAP		230.00	230.00	SSP T	0.06		1
34	RANCHO SECO	BELLOTA #1	230.00	230.00	T	27.39		1
35	RANCHO SECO	BELLOTA #2	230.00	230.00	T	27.36		1
36					TOTAL	36,892.15		1,445

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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	RAVENSWOOD	SAN MATEO #2	230.00	230.00	SSP T	11.88		1
2	RAVENSWOOD	SAN MATEO #1	230.00	230.00	SWP T	11.89		1
3	RIO OSO	ATLANTIC	230.00	230.00	SSP T	17.68		1
4	RIO OSO	BRIGHTON	230.00	230.00	T	27.17		1
5	RIO OSO	GOLD HILL	230.00	230.00	SSP T	28.63		1
6	RIO OSO	LOCKEFORD	230.00	230.00	T	65.13		1
7	ROCK CREEK	POE	230.00	230.00	SSP SWP T	26.98		1
8	ROSSMOOR #1 TAP		230.00	230.00	T	0.69		1
9	ROSSMOOR #2 TAP		230.00	230.00	T	0.66		1
10	ROUND MTN	COTTONWOOD #2	230.00	230.00	OTHER T	33.67		1
11	ROUND MTN	COTTONWOOD #3	230.00	230.00	SSP T	33.36		1
12	RUSSELL CITY ENERGY	EASTSHORE #1	230.00	230.00	SSP	1.19		1
13	RUSSELL CITY ENERGY	EASTSHORE #2	230.00	230.00	SSP	1.20		1
14	SAN MATEO	MARTIN	230.00	230.00	N/A	13.00		1
15	SAN RAMON	MORAGA	230.00	230.00	SWP T	22.24		1
16	SAN RAMON RESEARCH		230.00	230.00	SSP T	3.27		1
17	SANTA FE GEOTHERMAL		230.00	230.00	SSP T	1.04		1
18	SARATOGA	VASONA	230.00	230.00	SSP T	3.41		1
19	SHILOH II	BIRDS LANDING SW STA	230.00	230.00	SSP	3.56		1
20	SOLAR SW STA	CALIENTE SW STA #1	230.00	230.00	T	8.22		1
21	SOLAR SW STA	CALIENTE SW STA #2	230.00	230.00	T	8.22		1
22	SPI (BURNEY) TAP		230.00	230.00	T	0.05		1
23	STAGG	TESLA	230.00	230.00	OTHER T	23.64		1
24	STOCKDALE #1 TAP		230.00	230.00	SSP T	6.23		1
25	STOCKDALE #2 TAP		230.00	230.00	T	6.14		1
26	SVP	NORTHERN RECEIVING STA	230.00	230.00	N/A	2.36		
27	TABLE MTN	PALERMO	230.00	230.00	OTHER T	14.79		1
28	TABLE MTN	RIO OSO	230.00	230.00	OTHER T	50.40		1
29	TASSAJARA	NEWARK	230.00	230.00	SSP SWP T	31.80		1
30	TEMPLETON	GATES	230.00	230.00	T	52.18		1
31	TES TAP		230.00	230.00	SSP T	3.28		1
32	TESLA	NEWARK #2	230.00	230.00	SSP SWP T	40.88		1
33	TESLA	NEWARK #1	230.00	230.00	T	28.19		1
34	TESLA	RAVENSWOOD	230.00	230.00	SSP T	37.14		1
35	TESLA	TRACY #1	230.00	230.00	T	5.68		1
36					TOTAL	36,892.15		1,445

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1	TESLA	TRACY #2	230.00	230.00	T	5.68		1
2	TESLA	WESTLEY	230.00	230.00	T	45.06		1
3	TESORO	SOBRANTE	230.00	230.00	SSP T	12.32		1
4	TIDEWATER	SOBRANTE	230.00	230.00	SSP T	12.32		1
5	TIGER CREEK	ELECTRA	230.00	230.00	OTHER T	13.65		1
6	TIGER CREEK	VALLEY SPRINGS	230.00	230.00	OTHER T	24.22		1
7	TRANQUILLITY SW STA	HELM	230.00	230.00	SSP T	12.68		1
8	TRANQUILLITY SW STA	KEARNEY	230.00	230.00	SSP T T	0.03		1
9	TRANQUILLITY SW STA	KEARNEY	230.00	230.00	SSP T T	36.86		1
10	TULUCAY	VACA	230.00	230.00	SSP T	23.63		1
11	US WINDPOWER #3 TAP		230.00	230.00	SSP	0.06		1
12	VACA	BAHIA	230.00	230.00	SSP T	33.90		1
13	VACA	PEABODY	230.00	230.00	SSP T T	9.69		1
14	VACA	LAKEVILLE #1	230.00	230.00	SSP T	40.93		1
15	VACA	LAMBIE SW STA	230.00	230.00	T	13.95		1
16	VACA	PARKWAY	230.00	230.00	SSP T	27.76		1
17	VACA DIXON	MORAGA #1	230.00	230.00	T	3.08		1
18	VALLEY SPRINGS	BELLOTA	230.00	230.00	T	20.67		1
19	VASONA	METCALF	230.00	230.00	SSP T	13.29		1
20	VINEYARD	NEWARK	230.00	230.00	T	14.36		1
21	VINEYARD	NEWARK	230.00	230.00	N/A	5.94		1
22	WARNERVILLE	WILSON	230.00	230.00	SSP T	38.40		1
23	WEBER	TESLA	230.00	230.00	T	23.71		1
24	WHEELER RIDGE PUMPING		230.00	230.00	T	0.25		1
25	WHEELER RIDGE PUMPING		230.00	230.00	T	0.23		1
26	WILSON	GREGG	230.00	230.00	SSP T	41.44		1
27	WILSON	BORDEN	230.00	230.00	SSP T	35.37		1
28	WIND GAP PUMPING PLANT		230.00	230.00	T	1.64		1
29	WIND GAP PUMPING PLANT		230.00	230.00	T	1.62		1
30	WINDMASTER TAP		230.00	230.00	SSP T	0.11		1
31	ZA	1	230.00	230.00	N/A	3.41		1
32	7TH STANDARD	KERN	115.00	115.00	SSP SWP	6.75		1
33	A	P #1	115.00	115.00	N/A	2.46		1
34	A	H-W #1	115.00	115.00	N/A	4.95		1
35	A	X #1	115.00	115.00	N/A	2.67		1
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1	A	Y #1	115.00	115.00	N/A	3.33		1
2	A	Y #2	115.00	115.00	N/A	2.85		1
3	A	H-W #2	115.00	115.00	N/A	5.06		1
4	ADOBE SW STA	LAMONT	115.00	115.00	SSP SWP T	21.20		1
5	AEC SITE #1 TAP		115.00	115.00	OTHER SWP	1.60		1
6	AEC SITE #2 TAP		115.00	115.00	SSP SWP	2.16		1
7	AGNEW TAP		115.00	115.00	SSP SWP	1.62		1
8	AIR PRODUCTS TAP		115.00	115.00	SSP SWP	0.29		1
9	AMERIGAS TAP		115.00	115.00	SWP T	0.49		1
10	AMES DISTRIBUTION	AMES	115.00	115.00	SSP T	0.10		1
11	APPLE HILL #1 TAP		115.00	115.00	SSP SWP T	1.42		1
12	APPLE HILL #2 TAP		115.00	115.00	SSP SWP T	1.43		1
13	APPLIED MATERIALS	BRITTON	115.00	115.00	SSP T	0.47		1
14	APPLIED MATERIALS	BRITTON	115.00	115.00	N/A	0.74		1
15	ARVIN EDISON TAP		115.00	115.00	SWP T	1.06		1
16	ATLANTIC	PLEASANT GROVE #1	115.00	115.00	SSP SWP T	5.33		1
17	ATLANTIC	PLEASANT GROVE #2	115.00	115.00	SSP SWP T	5.36		1
18	ATWATER	EL CAPITAN	115.00	115.00	SSP T	7.31		1
19	ATWATER	LIVINGSTON-MERCED	115.00	115.00	SSP SWP	24.26		1
20	ATWATER	CRESSEY	115.00	115.00	SSP SWP	5.91		1
21	BADGER CREEK (PSE) TAP		115.00	115.00	SWP	1.07		1
22	BAIR	BELMONT	115.00	115.00	SSP T	3.64		1
23	BALCH	SANGER	115.00	115.00	OTHER SSP	35.62		1
24	BARKER SLOUGH TAP		115.00	115.00	SWP	1.62		1
25	BARTON	AIRWAYS-SANGER	115.00	115.00	OTHER SSP	11.65		1
26	BEAR MTN TAP		115.00	115.00	SSP SWP T	1.27		1
27	BEARDSLEY TAP		115.00	115.00	OTHER SWP	2.20		1
28	BELL	PLACER	115.00	115.00	SSP SWP T	7.94		1
29	BELLOTA	RIVERBANK-MELONES SW	115.00	115.00	OTHER SSP	44.65		1
30	BELLOTA	RIVERBANK	115.00	115.00	OTHER SSP	18.87		1
31	BELRIDGE TAP		115.00	115.00	SSP SWP	6.94		1
32	BIG BEND	CLAYTON #1	115.00	115.00	SWP T	11.98		1
33	BIG BEND	CLAYTON #2	115.00	115.00	T	11.98		1
34	BOGUE	RIO OSO	115.00	115.00	OTHER SSP	21.24		1
35	BOLLMAN #1 TAP		115.00	115.00	SSP T	2.14		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	BOLLMAN #2 TAP		115.00	115.00	SSP T	2.19		1
2	BOLTHOUSE FARMS TAP		115.00	115.00	SWP	0.11		1
3	BRIDGEVILLE	COTTONWOOD	115.00	115.00	OTHER SSP	86.06		1
4	BRIGHTON	CLAYTON #1	115.00	115.00	T	6.72		1
5	BRIGHTON	CLAYTON #2	115.00	115.00	T	6.72		1
6	BRIGHTON	DAVIS	115.00	115.00	OTHER SSP	42.73		1
7	BRIGHTON	DAVIS	115.00	115.00	OTHER SSP	17.36		1
8	BRIGHTON	GRAND ISLAND #1	115.00	115.00	OTHER SSP	43.46		1
9	BRIGHTON	GRAND ISLAND #2	115.00	115.00	OTHER SSP	43.47		1
10	BRITTON	MONTA VISTA	115.00	115.00	SSP T	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	SSP SWP T	18.17		1
15	BUTTE VALLEY	CARIBOU	115.00	115.00	OTHER 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	SSP SWP	14.58		1
20	CAL PEAK	VACA	115.00	115.00	SWP	0.11		1
21	CAL WATER TAP		115.00	115.00	SSP SWP	2.15		1
22	CALIFORNIA AVE	MCCALL	115.00	115.00	SSP SWP T	23.70		1
23	CALLENDER SW STA	MESA	115.00	115.00	SSP SWP T	13.77		1
24	CAMANCHE TAP		115.00	115.00	SWP T	6.71		1
25	CAMP EVERS	PAUL SWEET	115.00	115.00	SSP SWP T	5.22		1
26	CANTUA TAP		115.00	115.00	SSP SWP T	1.83		1
27	CARIBOU	PALERMO	115.00	115.00	OTHER SSP	54.89		1
28	CARQUINEZ #1 TAP		115.00	115.00	SSP T	0.51		1
29	CARQUINEZ #2 TAP		115.00	115.00	SSP T	0.52		1
30	CARRIZO PLAINS TAP		115.00	115.00	SSP	0.04		1
31	CASCADE	COTTONWOOD	115.00	115.00	OTHER SSP	19.46		1
32	CAWELO C TAP		115.00	115.00	SSP SWP	1.33		1
33	CERTAINTEED TAP		115.00	115.00	SSP SWP T	2.53		1
34	CHARCA	FAMOSO	115.00	115.00	SSP SWP	7.15		1
35	CHCF TAP		115.00	115.00	SSP SWP	3.00		1
36					TOTAL	36,892.15		1,445

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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	CHENEY #1 TAP		115.00	115.00	SSP SWP T	4.10		1
2	CHENEY #2 TAP		115.00	115.00	SWP T	1.97		1
3	CHINESE CAMP (ULTRA		115.00	115.00	SSP SWP	2.07		1
4	CHOWCHILLA	KERCKHOFF	115.00	115.00	OTHER 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	OTHER SSP	1.37		1
9	CLAYTON	MEADOW LANE	115.00	115.00	SSP SWP	7.06		1
10	COLES LEVEE TAP		115.00	115.00	SWP	0.22		1
11	COLUMBIA SOLAR 115kV		115.00	115.00	SSP SWP	0.45		1
12	CONTRA COSTA #1		115.00	115.00	SSP T	11.15		1
13	CONTRA COSTA #2		115.00	115.00	T	1.41		1
14	COOLEY LANDING	PALO ALTO	115.00	115.00	SSP SWP T	2.72		1
15	CORCORAN	OLIVE SW STA	115.00	115.00	SSP T	36.83		1
16	CORONA	LAKEVILLE	115.00	115.00	SSP SWP	5.79		1
17	CORTINA	MENDOCINO #1	115.00	115.00	SWP T	60.95		1
18	COTTONWOOD	PANORAMA	115.00	115.00	SSP SWP	2.95		1
19	CRAG VIEW	CASCADE	115.00	115.00	OTHER SWP	21.60		1
20	CRAZY HORSE CANYON	SAN BENITO	115.00	115.00	SSP T	8.95		1
21	CRAZY HORSE CANYON	HOLLISTER	115.00	115.00	SSP T	17.23		1
22	CRAZY HORSE CANYON	SALINAS-SOLEDAD #1	115.00	115.00	SSP T	35.35		1
23	CRAZY HORSE CANYON	SALINAS-SOLEDAD #2	115.00	115.00	SSP T	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	SSP SWP T	28.69		1
27	DANISH CREAMERY TAP		115.00	115.00	SSP SWP	1.20		1
28	DE FRANCESCO TAP		115.00	115.00	SSP SWP	1.02		1
29	DEEPWATER #1 TAP		115.00	115.00	SSP SWP T	2.29		1
30	DEEPWATER #2 TAP		115.00	115.00	SSP SWP T	2.45		1
31	DISCOVERY TAP		115.00	115.00	SSP SWP	2.10		1
32	DIVIDE	CABRILLO #2	115.00	115.00	OTHER SSP	11.55		1
33	DIVIDE	CABRILLO #1	115.00	115.00	OTHER SSP	14.60		1
34	DIXON LANDING	MCKEE	115.00	115.00	SSP SWP T	8.30		1
35	DOLAN RD #1 TAP		115.00	115.00	SSP T	0.32		1
36					TOTAL	36,892.15		1,445

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1	DOLAN RD #2 TAP		115.00	115.00	SSP T	0.33		1
2	DONNELLS	CURTIS	115.00	115.00	OTHER 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	OTHER SSP	44.64		1
5	DRUM	RIO OSO #2	115.00	115.00	OTHER SSP	44.65		1
6	DRUM	SUMMIT #1	115.00	115.00	OTHER SWP	27.36		1
7	DRUM	SUMMIT #2	115.00	115.00	OTHER SSP	28.36		1
8	DRUM	HIGGINS	115.00	115.00	OTHER SSP	47.75		1
9	DRUM PH #2 TAP		115.00	115.00	SSP SWP	0.09		1
10	DUMBARTON	NEWARK	115.00	115.00	SSP T	7.14		1
11	DUTCH FLAT #2 TAP		115.00	115.00	OTHER SWP	0.43		1
12	EAGLE ROCK	CORTINA	115.00	115.00	SSP SWP T	43.38		1
13	EAGLE ROCK	REDBUD	115.00	115.00	OTHER SSP	23.31		1
14	EAGLE ROCK	FULTON-SILVERADO	115.00	115.00	SSP T	46.94		1
15	EAST GRAND	SAN MATEO	115.00	115.00	OTHER 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	SSP T	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	T	1.00		1
20	EASTSHORE	CERBERUS	115.00	115.00	SSP	0.48		1
21	EBMUD TAP		115.00	115.00	OTHER SWP	0.02		1
22	EBMUD TAP		115.00	115.00	N/A	0.94		1
23	EDES #1 TAP		115.00	115.00	SSP SWP	0.05		1
24	EDES #2 TAP		115.00	115.00	SWP T	0.04		1
25	EL CAPITAN	WILSON	115.00	115.00	SSP T	8.12		1
26	EL DORADO	MISSOURI FLAT #1	115.00	115.00	SSP SWP	14.43		1
27	EL DORADO	MISSOURI FLAT #2	115.00	115.00	SSP SWP	14.41		1
28	EL PATIO	SAN JOSE A	115.00	115.00	SSP SWP T	7.08		1
29	ELLIS TAP		115.00	115.00	SWP T	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	SSP T	5.24		1
32	EXCELSIOR SW STA	SCHINDLER #2	115.00	115.00	SSP T	5.23		1
33	EXCHEQUER	LE GRAND	115.00	115.00	SSP SWP T	29.75		1
34	FAIRVIEW	MARTINEZ SW STA	115.00	115.00	SWP	0.10		1
35	FAIRWAY #1 TAP		115.00	115.00	OTHER SSP	2.83		1
36					TOTAL	36,892.15		1,445

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1	FAIRWAY #2 TAP		115.00	115.00	OTHER SSP	1.52		1
2	FELLOWS	MIDSUN	115.00	115.00	OTHER SSP	4.73		1
3	FELLOWS	TAFT	115.00	115.00	OTHER SSP	7.93		1
4	FIBREBOARD STANDARD		115.00	115.00	SWP	0.02		1
5	FIBREBOARD TAP		115.00	115.00	SSP SWP T	1.03		1
6	FLINT TAP		115.00	115.00	SSP SWP T	1.96		1
7	FMC	SAN JOSE B	115.00	115.00	SSP T	1.61		1
8	FORBESTOWN TAP		115.00	115.00	SWP T	0.22		1
9	FRITO LAY TAP		115.00	115.00	SSP SWP T	0.53		1
10	FROGTOWN #1 TAP		115.00	115.00	T	0.12		1
11	FROGTOWN #2 TAP		115.00	115.00	T	0.11		1
12	FULTON	PUEBLO	115.00	115.00	OTHER SSP	59.90		1
13	FULTON	SANTA ROSA #1	115.00	115.00	SSP SWP T	6.69		1
14	FULTON	SANTA ROSA #2	115.00	115.00	SSP SWP T	6.29		1
15	FULTON JCT	VACA	115.00	115.00	SSP T	11.93		1
16	GALLO	LIVINGSTON	115.00	115.00	SSP SWP	4.20		1
17	GALLO	CRESSEY	115.00	115.00	SSP SWP	14.43		1
18	GEYSERS #11	EAGLE ROCK	115.00	115.00	SSP T	0.64		1
19	GEYSERS #3	CLOVERDALE	115.00	115.00	OTHER SSP	12.07		1
20	GEYSERS #3	EAGLE ROCK	115.00	115.00	OTHER 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	OTHER SSP	1.40		1
23	GILL RANCH TAP		115.00	115.00	SSP SWP	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	SSP T	87.28		1
27	GOLD HILL	CLARKSVILLE	115.00	115.00	SSP T	5.77		1
28	GOLDEN VALLEY TAP		115.00	115.00	SSP SWP	1.59		1
29	GOLDTREE TAP		115.00	115.00	SWP T	2.30		1
30	GRANT	EASTSHORE #1	115.00	115.00	SSP T	4.33		1
31	GRANT	EASTSHORE #2	115.00	115.00	T	4.20		1
32	GREEN VALLEY	CAMP EVERS	115.00	115.00	OTHER SSP	18.59		1
33	GREEN VALLEY	LLAGAS	115.00	115.00	OTHER SSP	24.85		1
34	GREEN VALLEY	PAUL SWEET	115.00	115.00	OTHER SWP	16.03		1
35	GREENLEAF #1 TAP		115.00	115.00	SSP SWP	4.84		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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	GRIZZLY TAP (SVP)		115.00	115.00	SWP T	0.16		1
2	GUARDIAN #1 TAP		115.00	115.00	SSP SWP	0.75		1
3	GUARDIAN #2 TAP		115.00	115.00	SWP	0.13		1
4	GWF	KINGSBURG	115.00	115.00	SSP SWP	21.62		1
5	H	P #3	115.00	115.00	OTHER T	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	HENRIETTA	LEPRINO SW STA	115.00	115.00	SSP SWP	6.03		1
11	HERNDON	BARTON	115.00	115.00	OTHER SSP	12.70		1
12	HERNDON	BULLARD #1	115.00	115.00	SSP SWP T	11.44		1
13	HERNDON	BULLARD #2	115.00	115.00	SSP SWP T	11.44		1
14	HERNDON	MANCHESTER	115.00	115.00	OTHER SSP	9.29		1
15	HERNDON	WOODWARD	115.00	115.00	SSP SWP T	12.94		1
16	HERSHEY TAP		115.00	115.00	SWP	6.12		1
17	HIGGINS	BELL	115.00	115.00	SSP SWP T	18.77		1
18	HONCUT TAP		115.00	115.00	SSP T	1.65		1
19	HOWLAND ROAD TAP		115.00	115.00	SSP SWP	0.90		1
20	HUMBOLDT	BRIDGEVILLE	115.00	115.00	OTHER SSP	30.28		1
21	HUMBOLDT	TRINITY	115.00	115.00	OTHER SSP	68.57		1
22	HUMBOLDT BAY	HUMBOLDT #1	115.00	115.00	SSP T	6.31		1
23	IBM BAILEY AVE TAP		115.00	115.00	SSP SWP T	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 T	0.58		1
26	IGNACIO	MARE ISLAND #1	115.00	115.00	SSP SWP T	39.48		1
27	IGNACIO	MARE ISLAND #2	115.00	115.00	SSP SWP T	43.08		1
28	IGNACIO	SAN RAFAEL #1	115.00	115.00	SSP T	11.54		1
29	IGNACIO	SAN RAFAEL #3	115.00	115.00	OTHER SWP	8.65		1
30	IMHOFF TAP		115.00	115.00	SWP T	1.43		1
31	INGRAM CREEK TAP		115.00	115.00	SWP	0.50		1
32	JAMESON CANYON		115.00	115.00	SSP SWP	0.19		1
33	JARVIS	CRYOGENICS	115.00	115.00	T	0.03		1
34	JESSUP TAP		115.00	115.00	OTHER SSP	0.86		1
35	K	D #1	115.00	115.00	N/A	2.44		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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 T	0.52		1
3	KANAKA TAP		115.00	115.00	OTHER 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	OTHER SSP	37.07		1
6	KERCKHOFF	CLOVIS-SANGER #2	115.00	115.00	SSP SWP T	32.05		1
7	KERCKHOFF #1	KERCKHOFF #2	115.00	115.00	SSP T	1.58		1
8	KERN	KERN FRONT	115.00	115.00	OTHER SSP	12.52		1
9	KERN	TEVIS-STOCKDALE-LAMON	115.00	115.00	SSP SWP T	21.52		1
10	KERN	LIVE OAK	115.00	115.00	SWP OTHER	10.74		1
11	KERN	MAGUNDEN-WITCO	115.00	115.00	OTHER SSP	19.57		1
12	KERN	ROSEDALE	115.00	115.00	SWP T	1.71		1
13	KERN	TEVIS-STOCKDALE	115.00	115.00	SSP SWP T	19.74		1
14	KERN	TEVIS-STOCKDALE (21KV)	115.00	115.00	SSP SWP T	0.67		1
15	KERN	WESTPARK #1	115.00	115.00	SSP T	3.84		1
16	KERN	WESTPARK #2	115.00	115.00	SSP T	3.83		1
17	KERN OIL	DEXZEL	115.00	115.00	SWP	0.44		1
18	KERN OIL	WITCO	115.00	115.00	SSP T	4.54		1
19	KERNWATER TAP		115.00	115.00	SSP SWP T	0.67		1
20	KIFER	FMC	115.00	115.00	SSP T	6.01		1
21	KIFER	FMC	115.00	115.00	N/A	1.11		1
22	KINGS RIVER	SANGER-REEDLEY	115.00	115.00	SSP SWP T	43.35		1
23	KINGSBURG	CORCORAN #1	115.00	115.00	SSP T	27.16		1
24	KINGSBURG	WAUKENA SW STA	115.00	115.00	SSP SSP T	24.94		1
25	KINGSBURG COGEN TAP		115.00	115.00	SSP SWP	1.22		1
26	KM GREEN TAP		115.00	115.00	SSP	0.20		1
27	KYOHO TAP		115.00	115.00	SSP SWP	2.20		1
28	LAKEVILLE	SONOMA #1	115.00	115.00	SSP SWP	6.68		1
29	LAKEVILLE	SONOMA #2	115.00	115.00	SSP SWP	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	SSP SWP T	9.55		1
32	LAKEWOOD	CLAYTON	115.00	115.00	SSP T	5.52		1
33	LAMMERS	KASSON	115.00	115.00	SSP SWP T	8.23		1
34	LAMONT	GRIMMWAY MALAGA	115.00	115.00	SSP SWP	3.55		1
35	LAS PALMAS TAP	--LAS PALMAS TAP	115.00	115.00	SSP SWP	0.85		1
36					TOTAL	36,892.15		1,445

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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	LAS PLUMAS TAP		115.00	115.00	SSP SWP	0.48		1
2	LAWRENCE	MONTA VISTA	115.00	115.00	SSP SWP T	9.44		1
3	LAWRENCE LIVERMORE		115.00	115.00	SSP SWP T	9.00		1
4	LAWRENCE LIVERMORE		115.00	115.00	SWP T	9.41		1
5	LE GRAND	DAIRYLAND	115.00	115.00	SSP SWP T	11.40		1
6	LE GRAND	CHOWCHILLA	115.00	115.00	SSP SWP T	10.94		1
7	LEPRINO FOODS	LEPRINO SW STA	115.00	115.00	SSP SWP	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	SSP SWP	12.38		1
11	LERDO	KERN OIL-7TH STANDARD	115.00	115.00	OTHER SSP	16.34		1
12	LERDO	FAMOSO	115.00	115.00	SSP SWP T	13.44		1
13	LINCOLN	PLEASANT GROVE	115.00	115.00	OTHER SSP	7.38		1
14	LINDE TAP		115.00	115.00	SSP SWP T	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 T	1.98		1
18	LLAGAS	HOLLISTER	115.00	115.00	SSP SWP T	21.56		1
19	LOCKHEED #1 TAP		115.00	115.00	SSP SWP T	1.72		1
20	LOCKHEED #2 TAP		115.00	115.00	SSP SWP	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	SSP SWP	1.37		1
24	LOS ESTEROS	NORTECH	115.00	115.00	SSP	1.98		1
25	LOWER LAKE	HOMESTAKE	115.00	115.00	SSP SWP	16.12		1
26	LUCERNE #1 TAP		115.00	115.00	SWP T	0.23		1
27	LUCERNE #2 TAP		115.00	115.00	SSP SWP T	0.23		1
28	MABURY TAP		115.00	115.00	SSP SWP	2.81		1
29	MADISON	VACA	115.00	115.00	OTHER SSP	22.99		1
30	MALAGA	KRCD	115.00	115.00	SWP	0.99		1
31	MANCHESTER	AIRWAYS-SANGER	115.00	115.00	OTHER SSP	15.07		1
32	MANTECA	VIERRA	115.00	115.00	SSP SWP	3.98		1
33	MANVILLE TAP		115.00	115.00	OTHER SSP	5.51		1
34	MARTIN	DALY CITY #1	115.00	115.00	T	3.93		1
35	MARTIN	DALY CITY #2	115.00	115.00	T	3.93		1
36					TOTAL	36,892.15		1,445

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

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1	MARTIN	EAST GRAND	115.00	115.00	SSP SWP T	3.96		1
2	MARTIN	MILLBRAE #1	115.00	115.00	SSP T	7.28		1
3	MARTIN	SF AIRPORT	115.00	115.00	SSP T	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 SWP T	16.40		1
9	MCCALL	KINGSBURG #1	115.00	115.00	SSP SWP	11.65		1
10	MCCALL	KINGSBURG #2	115.00	115.00	SSP T	11.57		1
11	MCCALL	MALAGA	115.00	115.00	SSP SWP T	10.96		1
12	MCCALL	REEDLEY	115.00	115.00	OTHER SSP	15.20		1
13	MCCALL	SANGER #1	115.00	115.00	SSP T	9.23		1
14	MCCALL	SANGER #2	115.00	115.00	SSP T	9.20		1
15	MCCALL	SANGER #3	115.00	115.00	SWP T	8.30		1
16	MCCALL	WEST FRESNO #2	115.00	115.00	SSP T	19.61		1
17	MCKEE	PIERCY	115.00	115.00	SSP T	7.75		1
18	MELONES	CURTIS	115.00	115.00	OTHER SSP	14.80		1
19	MELONES	RACETRACK	115.00	115.00	SSP SWP	10.20		1
20	MENDOCINO	REDBUD	115.00	115.00	SSP T	34.83		1
21	MENDOCINO	UKIAH	115.00	115.00	OTHER SSP	9.83		1
22	MENDOTA	NORTH STAR SOLAR	115.00	115.00		0.03		1
23	MESA	DIVIDE #1	115.00	115.00	SSP T	14.71		1
24	MESA	DIVIDE #2	115.00	115.00	SSP T	14.72		1
25	MESA	SANTA MARIA	115.00	115.00	SSP SWP T	4.36		1
26	MESA	SISQUOC	115.00	115.00	SSP SWP T	17.60		1
27	METCALF	SALINAS #1	115.00	115.00	T	1.94		1
28	METCALF	SALINAS #2 (12KV)	115.00	115.00	SWP T	6.80		1
29	METCALF	COYOTE PUMPING PLANT	115.00	115.00	SWP	7.86		1
30	METCALF	EDENVALE #1	115.00	115.00	SSP T	5.73		1
31	METCALF	EDENVALE #2	115.00	115.00	T	5.60		1
32	METCALF	EL PATIO #1	115.00	115.00	SSP T	14.39		1
33	METCALF	EL PATIO #2	115.00	115.00	SSP T	14.40		1
34	METCALF	EVERGREEN #1	115.00	115.00	T	10.63		1
35	METCALF	GREEN VALLEY	115.00	115.00	OTHER SSP	25.28		1
36					TOTAL	36,892.15		1,445

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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 T	9.72		1
2	METCALF	HICKS 1 & 2	115.00	115.00	T SSP T	6.62		1
3	MIDSET TAP		115.00	115.00	SWP	0.72		1
4	MIDSUN	MIDWAY	115.00	115.00	OTHER SSP	18.86		1
5	MIDWAY	RENFRO-TUPMAN	115.00	115.00	OTHER SSP	22.60		1
6	MIDWAY	TUPMAN-RIO	115.00	115.00	OTHER SSP	26.59		1
7	MIDWAY	SHAFTER	115.00	115.00	SSP SWP T	13.63		1
8	MIDWAY	TAFT	115.00	115.00	OTHER SSP	19.33		1
9	MIDWAY	TEMBLOR	115.00	115.00	OTHER SSP	14.50		1
10	MIDWAY	SANTA MARIA	115.00	115.00	SWP T	46.72		1
11	MILLBRAE	SAN MATEO #1	115.00	115.00	SSP T	4.71		1
12	MILLER #1 TAP		115.00	115.00	SSP SWP T	21.26		1
13	MILLER #2 TAP		115.00	115.00	OTHER SSP	12.32		1
14	MILPITAS	SWIFT	115.00	115.00	SSP T	8.86		1
15	MISSION POWER TAP		115.00	115.00	SSP SWP	1.94		1
16	MISSOURI FLAT	GOLD HILL #1	115.00	115.00	SSP T	19.73		1
17	MISSOURI FLAT	GOLD HILL #2	115.00	115.00	SSP T	19.69		1
18	MOFFETT FIELD TAP		115.00	115.00	SSP SWP	0.16		1
19	MONTA VISTA	WOLFE	115.00	115.00	SSP T	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	SSP SWP T	0.62		1
23	MORAGA	CLAREMONT #1	115.00	115.00	OTHER T	5.28		1
24	MORAGA	CLAREMONT #2	115.00	115.00	OTHER T	5.30		1
25	MORAGA	OAKLAND #1	115.00	115.00	SSP T	5.04		1
26	MORAGA	OAKLAND #2	115.00	115.00	SSP T	5.04		1
27	MORAGA	OAKLAND #3	115.00	115.00	SSP SWP T	5.05		1
28	MORAGA	OAKLAND #4	115.00	115.00	SSP SWP T	5.05		1
29	MORAGA	OAKLAND J	115.00	115.00	SSP SWP T	17.67		1
30	MORAGA	SAN LEANDRO #1	115.00	115.00	SSP T	11.14		1
31	MORAGA	SAN LEANDRO #2	115.00	115.00	SSP SWP T	11.01		1
32	MORAGA	SAN LEANDRO #3	115.00	115.00	T	11.00		1
33	MORAGA	LAKEWOOD	115.00	115.00	SSP OTHER	15.11		1
34	MORGAN HILL	LLAGAS	115.00	115.00	SSP SWP T	10.84		1
35	MORRO BAY	SAN LUIS OBISPO #1	115.00	115.00	T	16.01		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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)	Structure (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	SSP T	23.35		1
3	MOSS LANDING	DEL MONTE #2	115.00	115.00	SSP T	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 T	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 T	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	T	10.61		1
10	MTN VIEW	MONTA VISTA	115.00	115.00	T	4.80		1
11	NEWARK	AMES #1	115.00	115.00	SSP T	8.30		1
12	NEWARK	AMES #2	115.00	115.00	SSP T	8.28		1
13	NEWARK	AMES #3	115.00	115.00	SWP T	8.28		1
14	NEWARK	APPLIED MATERIALS	115.00	115.00	OTHER SSP	11.37		1
15	NEWARK	DIXON LANDING	115.00	115.00	SSP T	4.69		1
16	NEWARK	FREMONT #1	115.00	115.00	SSP T	3.71		1
17	NEWARK	FREMONT #2	115.00	115.00	SSP T	3.75		1
18	NEWARK	JARVIS #1	115.00	115.00	SSP T	14.25		1
19	NEWARK	JARVIS #2	115.00	115.00	SSP T	14.48		1
20	NEWARK	KIFER	115.00	115.00	SSP T	10.61		1
21	NEWARK	LAWRENCE	115.00	115.00	OTHER	10.25		1
22	NEWARK	LAWRENCE LAB	115.00	115.00	T	12.21		1
23	NEWARK	MILPITAS #1	115.00	115.00	SSP T	8.48		1
24	NEWARK	MILPITAS #2	115.00	115.00	SSP SWP	10.30		1
25	NEWARK	NUMMI	115.00	115.00	SSP SWP T	4.94		1
26	NEWARK	NORTHERN RECEIVING	115.00	115.00	SSP T	8.76		1
27	NEWARK	NORTHERN RECEIVING	115.00	115.00	SSP T	8.67		1
28	NEWARK	TRIMBLE	115.00	115.00	SSP T	12.36		1
29	NEWARK	AMES DISTRIBUTION	115.00	115.00	SSP SWP T	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	SSP T	2.08		1
34	NORTHERN RECEIVING	SCOTT #2	115.00	115.00	SSP T	1.98		1
35	NOTRE DAME	BUTTE	115.00	115.00	SSP SWP	2.02		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	OAKHURST TAP		115.00	115.00	OTHER SSP	18.16		1
2	OAKLAND C	MARITIME	115.00	115.00	SSP SWP	2.36		1
3	OAKLAND C	TURBINES	115.00	115.00	SSP SWP	0.19		1
4	OAKLAND J	GRANT	115.00	115.00	SSP T	14.81		1
5	OCEANO	CALLENDER SW STA	115.00	115.00	SSP SWP	4.22		1
6	OLEUM	G #1	115.00	115.00	SSP T	11.29		1
7	OLEUM	G #2	115.00	115.00	SSP OTHER	11.30		1
8	OLEUM	MARTINEZ	115.00	115.00	SSP SWP T	10.50		1
9	OLEUM	NORTH TOWER-CHRISTIE	115.00	115.00	OTHER 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	SSP T	22.09		1
13	OWENS BROCKWAY TAP		115.00	115.00	SSP SWP T	1.09		1
14	OWENS ILLINOIS TAP		115.00	115.00	SSP SWP T	0.68		1
15	OXFORD TAP		115.00	115.00	SWP T	3.87		1
16	P	X #2	115.00	115.00	SSP T	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	OTHER SSP	35.74		1
20	PALERMO	NICOLAUS	115.00	115.00	OTHER SSP	41.18		1
21	PALERMO	PEASE	115.00	115.00	T	26.53		1
22	PALERMO	WYANDOTTE	115.00	115.00	SSP SWP T	5.30		1
23	PANOCHE	CAL PEAK-STARWOOD	115.00	115.00	SWP	0.10		1
24	PANOCHE	MENDOTA	115.00	115.00	SSP SWP	10.08		1
25	PANOCHE	ORO LOMA	115.00	115.00	SSP SWP T	18.96		1
26	PANOCHE	EXCELSIOR #1	115.00	115.00	SSP T SSP	28.50		1
27	PANOCHE	EXCELSIOR #2	115.00	115.00	SSP T	28.50		1
28	PARADISE	TABLE MTN	115.00	115.00	OTHER SSP	33.73		1
29	PARADISE	BUTTE	115.00	115.00	OTHER SSP	13.58		1
30	PARAMOUNT FARMS TAP		115.00	115.00	SSP SWP	0.57		1
31	PEASE	RIO OSO	115.00	115.00	SSP SWP T	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	SSP T	16.82		1
36					TOTAL	36,892.15		1,445

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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	PITTSBURG	CLAYTON #3	115.00	115.00	SSP T	8.41		1
2	PITTSBURG	CLAYTON #4	115.00	115.00	SSP T	8.32		1
3	PITTSBURG	COLUMBIA STEEL	115.00	115.00	SSP T	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 T	9.26		1
7	PITTSBURG	MARTINEZ #1	115.00	115.00	SSP T	17.22		1
8	PITTSBURG	MARTINEZ #2	115.00	115.00	SSP T	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	SSP SWP T	20.67		1
12	PLACER	GOLD HILL #2	115.00	115.00	SSP T	20.67		1
13	POINT PINOLE TAP		115.00	115.00	SSP SWP T	1.30		1
14	POST OFFICE TAP		115.00	115.00	SSP SWP	0.75		1
15	PSE MCKITTRICK TAP		115.00	115.00	SWP	5.21		1
16	QUEBEC TAP		115.00	115.00	SSP SWP	4.35		1
17	RACETRACK TAP		115.00	115.00	SSP SWP	3.55		1
18	RAINBOW TAP		115.00	115.00	SSP SSP T	2.59		1
19	RANCHERS COTTON TAP		115.00	115.00	SSP SWP	2.10		1
20	RAVENSWOOD	AMES #1	115.00	115.00	T	7.07		1
21	RAVENSWOOD	AMES #2	115.00	115.00	T	7.09		1
22	RAVENSWOOD	BAIR #1	115.00	115.00	T	7.43		1
23	RAVENSWOOD	BAIR #2	115.00	115.00	SSP T	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	T	1.62		1
26	RAVENSWOOD	PALO ALTO #1	115.00	115.00	SSP SWP T	4.28		1
27	RAVENSWOOD	PALO ALTO #2	115.00	115.00	SSP SWP T	4.26		1
28	RAVENSWOOD	SAN MATEO	115.00	115.00	T	12.04		1
29	RINCON #1 TAP		115.00	115.00	SSP T	0.57		1
30	RINCON #2 TAP		115.00	115.00	SSP T	0.55		1
31	RIO BRAVO	KERN OIL	115.00	115.00	SSP SWP	7.28		1
32	RIO BRAVO (FRESNO) TAP		115.00	115.00	SSP SWP	0.32		1
33	RIO BRAVO (ROCKLIN) TAP		115.00	115.00	SSP SWP	0.40		1
34	RIO BRAVO TOMATO TAP		115.00	115.00	OTHER SSP	0.43		1
35	RIO OSO	LINCOLN	115.00	115.00	OTHER SSP	11.02		1
36					TOTAL	36,892.15		1,445

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1	RIO OSO	NICOLAUS	115.00	115.00	T	5.39		1
2	RIO OSO	WEST SACRAMENTO	115.00	115.00	OTHER SSP	43.56		1
3	RIO OSO	WOODLAND #1	115.00	115.00	OTHER SSP	45.25		1
4	RIO OSO	WOODLAND #2	115.00	115.00	SSP SWP T	53.37		1
5	RIPON TAP		115.00	115.00	SWP T	4.64		1
6	RIVERBANK JCT SW STA	MANTECA	115.00	115.00	SSP T	17.65		1
7	SAFEWAY TAP		115.00	115.00	SWP T	0.70		1
8	SALT SPRINGS	TIGER CREEK	115.00	115.00	SSP T	16.48		1
9	SAN BENITO	HOLLISTER	115.00	115.00	SSP	8.31		1
10	SAN FRANCISCO #2		115.00	115.00	T	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	SSP SWP	8.56		1
14	SAN LEANDRO	OAKLND J #1	115.00	115.00	SSP T	6.71		1
15	SAN LUIS #3 TAP		115.00	115.00	SSP SWP T	16.11		1
16	SAN LUIS #5 TAP		115.00	115.00	SSP SWP	1.88		1
17	SAN LUIS OBISPO	OCEANO	115.00	115.00	OTHER SSP	19.90		1
18	SAN LUIS OBISPO	SANTA MARIA	115.00	115.00	SSP SWP T	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	SSP T SSP	7.20		1
22	SAN MATEO	MARTIN #3	115.00	115.00	SSP SWP T	11.55		1
23	SAN MATEO	MARTIN #6	115.00	115.00	SSP T	11.68		1
24	SAN MATEO	MARTIN #4	115.00	115.00	SSP SWP T	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 T	0.44		1
29	SAN PABLO #2 TAP		115.00	115.00	SSP T	0.45		1
30	SANDBAR TAP		115.00	115.00	SWP	0.09		1
31	SANGER	MALAGA	115.00	115.00	SSP SWP T	8.82		1
32	SANGER	CALIFORNIA AVE	115.00	115.00	SSP SWP	9.33		1
33	SANGER	REEDLEY	115.00	115.00	SSP SWP	20.42		1
34	SANGER COGEN TAP		115.00	115.00	SSP SWP	0.83		1
35	SANTA MARIA	SISQUOC	115.00	115.00	SSP SWP	10.57		1
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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	SSP SWP	14.39		1
4	SANTA YNEZ TAP		115.00	115.00	SSP SWP	4.06		1
5	SARGENT SW STA	HOLLISTER	115.00	115.00	OTHER SWP	1.54		1
6	SCHULTE SW STA	LAMMERS	115.00	115.00	SSP T	0.69		1
7	SCHULTE SW STA	KASSON-MANTECA	115.00	115.00	OTHER SSP	16.56		1
8	SEMITROPIC	CHARCA	115.00	115.00	SSP SWP	6.90		1
9	SEMITROPIC	MIDWAY #1	115.00	115.00	SSP SWP T	14.10		1
10	SEMITROPIC	MIDWAY #2	115.00	115.00	SSP SWP	20.09		1
11	SERRAMONTE TAP		115.00	115.00	SSP T	2.55		1
12	SF AIRPORT	SAN MATEO	115.00	115.00	SSP T	6.09		1
13	SHAFTER	RIO BRAVO	115.00	115.00	SSP SWP T	8.31		1
14	SHARON PRISON TAP		115.00	115.00	SSP SWP	2.57		1
15	SHREDDER TAP		115.00	115.00	SSP SWP T	1.38		1
16	SIERRA #1		115.00	115.00	T	5.47		1
17	SIERRA #2		115.00	115.00	T	4.86		1
18	SIERRA (PSE) TAP		115.00	115.00	SSP SWP	1.81		1
19	SIERRA PACIFIC IND TAP		115.00	115.00	SSP SWP	0.06		1
20	SILVERADO	FULTON JCT	115.00	115.00	SWP T	26.16		1
21	SISQUOC	GAREY	115.00	115.00	SSP SWP	5.02		1
22	SISQUOC	SANTA YNEZ SW STA	115.00	115.00	OTHER SWP	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	OTHER SSP	5.34		1
26	SMYRNA	SEMITROPIC-MIDWAY	115.00	115.00	OTHER SSP	44.65		1
27	SOBRANTE	G #1	115.00	115.00	SSP SWP T	5.34		1
28	SOBRANTE	G #2	115.00	115.00	SSP T	5.31		1
29	SOBRANTE	GRIZZLY-CLAREMONT #1	115.00	115.00	SSP SWP T	19.57		1
30	SOBRANTE	MORAGA	115.00	115.00	SSP SWP T	5.68		1
31	SOBRANTE	GRIZZLY-CLAREMONT #2	115.00	115.00	SSP SWP T	19.30		1
32	SOBRANTE	R #1	115.00	115.00	SSP T	5.54		1
33	SOBRANTE	R #2	115.00	115.00	SSP T	5.53		1
34	SOBRANTE	STANDARD OIL SW STA #2	115.00	115.00	SSP OTHER	18.89		1
35	SOBRANTE	STANDARD OIL SW STA #1	115.00	115.00	SSP OTHER	18.89		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	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	SSP SWP	18.48		1
4	SPRING GAP TAP		115.00	115.00	OTHER SWP	1.64		1
5	STANISLAUS	MANTECA #2	115.00	115.00	SSP SWP T	53.95		1
6	STANISLAUS	MELONES SW	115.00	115.00	SSP SWP T	61.15		1
7	STANISLAUS	MELONES SW	115.00	115.00	SSP SWP T	43.80		1
8	STANISLAUS	NEWARK #1 (12KV)	115.00	115.00	SSP T	15.05		1
9	STANISLAUS	NEWARK #2 (12KV)	115.00	115.00	SSP SWP T	18.17		1
10	STELLING	MONTA VISTA	115.00	115.00	SSP T	1.61		1
11	STELLING	WOLFE	115.00	115.00	SSP T	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	OTHER SSP	34.73		1
14	STOCKTON A	LOCKEFORD-BELLOTA #2	115.00	115.00	SSP SWP T	34.49		1
15	STONE	EVERGREEN-METCALF	115.00	115.00	SSP SWP T	12.86		1
16	STONY POINT TAP		115.00	115.00	SSP SWP	3.08		1
17	SURF TAP		115.00	115.00	OTHER 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	SSP SWP T	20.33		1
20	TABLE MTN	BUTTE #1	115.00	115.00	SSP SWP T	19.54		1
21	TABLE MTN	BUTTE #2	115.00	115.00	SSP T	15.82		1
22	TAFT	CHALK CLIFF	115.00	115.00	OTHER SSP	7.18		1
23	TEICHERT TAP		115.00	115.00	OTHER SSP	2.11		1
24	TEMBLOR	KERNRIDGE	115.00	115.00	SSP SWP	4.80		1
25	TEMBLOR	SAN LUIS OBISPO	115.00	115.00	SSP SWP T	57.80		1
26	TESLA	SCHULTE SW STA #2	115.00	115.00	SSP SSP T	7.34		1
27	TESLA	SCHULTE SW STA #1	115.00	115.00	OTHER SSP	7.39		1
28	TESLA	SALADO #1	115.00	115.00	OTHER SSP	32.07		1
29	TESLA	SALADO-MANTECA	115.00	115.00	OTHER SSP	53.96		1
30	TESLA	STOCKTON COGEN JCT	115.00	115.00	SSP SWP T	44.51		1
31	TESLA	TRACY	115.00	115.00	SSP SWP T	25.23		1
32	THERMAL ENERGY TAP		115.00	115.00	SSP SWP	0.74		1
33	TRIMBLE	SAN JOSE B	115.00	115.00	SSP T	2.53		1
34	TRIMBLE	SAN JOSE B	115.00	115.00	N/A	1.11		1
35	TRINITY	COTTONWOOD	115.00	115.00	OTHER SSP	45.97		1
36					TOTAL	36,892.15		1,445

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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	TULLOCH TAP		115.00	115.00	SWP	0.31		1
2	TUPMAN	NORCO TAP	115.00	115.00	SSP SWP	6.67		1
3	UC DAVIS #1 TAP		115.00	115.00	SSP SWP	1.64		1
4	UC DAVIS #2 TAP		115.00	115.00	SSP SWP	1.61		1
5	UKIAH	HOPLAND-CLOVERDALE	115.00	115.00	OTHER SSP	31.17		1
6	ULTRAPOWER (OGLE) TAP		115.00	115.00	OTHER SSP	2.45		1
7	UNION OIL TAP		115.00	115.00	SSP SWP	0.50		1
8	UNITED COGEN INC TAP		115.00	115.00	SSP SWP T	0.68		1
9	UNIVERSITY COGEN TAP		115.00	115.00	SWP	0.22		1
10	VACA	SUISUN	115.00	115.00	SSP SWP T	23.06		1
11	VACA	SUISUN-JAMESON	115.00	115.00	SSP SWP T	25.46		1
12	VACA	VACAVILLE-CORDELIA	115.00	115.00	SSP SWP T	22.04		1
13	VACA	VACAVILLE-JAMESON-NOR	115.00	115.00	SSP SWP T	36.18		1
14	VALLEY CHILDRENS		115.00	115.00	SSP	0.03		1
15	VALLEY VIEW #1 TAP		115.00	115.00	SSP T	0.96		1
16	VALLEY VIEW #2 TAP		115.00	115.00	SSP T	0.97		1
17	VEDDER TAP		115.00	115.00	OTHER SSP	11.09		1
18	VIERRA	TRACY-KASSON	115.00	115.00	SSP SWP T	10.49		1
19	WASCO PRISON TAP		115.00	115.00	SSP SWP	0.54		1
20	WAUKENA SW STA	CORCORAN	115.00	115.00	SSP T	2.37		1
21	WEST FRESNO	CALIFORNIA AVE	115.00	115.00	SWP T	4.90		1
22	WEST SACRAMENTO	BRIGHTON	115.00	115.00	OTHER SSP	13.97		1
23	WEST SACRAMENTO	DAVIS	115.00	115.00	OTHER SSP	12.14		1
24	WESTLANDS #1 RA		115.00	115.00	SSP SWP T	1.05		1
25	WESTLANDS #18 RA TAP		115.00	115.00	SSP SWP	3.52		1
26	WESTPARK	MAGUNDEN	115.00	115.00	SSP SWP	12.27		1
27	WHEELER RIDGE	ADOBE SW STA	115.00	115.00	SSP SWP	1.34		1
28	WHISMAN	MONTA VISTA	115.00	115.00	T	5.97		1
29	WHISMAN	MTN VIEW	115.00	115.00	SWP T	3.54		1
30	WILSON	DAIRYLAND (12KV)	115.00	115.00	SWP	11.37		1
31	WILSON	ATWATER #2	115.00	115.00	SSP T	15.41		1
32	WILSON	LE GRAND	115.00	115.00	SSP SWP T	14.04		1
33	WILSON	MERCED #1	115.00	115.00	SSP SWP T	5.58		1
34	WILSON	MERCED #2	115.00	115.00	SSP SWP T	6.20		1
35	WILSON	ORO LOMA	115.00	115.00	SSP SWP T	43.56		1
36					TOTAL	36,892.15		1,445

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1	WITCO (REFINERY) TAP		115.00	115.00	SSP SWP	0.03		1
2	WOODLAND	DAVIS	115.00	115.00	SSP SWP T	11.71		1
3	WOODLAND BIOMASS TAP		115.00	115.00	SWP	0.87		1
4	WOODLEAF	PALERMO	115.00	115.00	OTHER SSP	19.62		1
5	WOODWARD	SHEPHERD	115.00	115.00	SSP SWP	4.84		1
6	X	Y #1	115.00	115.00	N/A	0.57		1
7	ZAMORA TAP		115.00	115.00	SSP SWP T	1.92		1
8	ZANKER #1 TAP		115.00	115.00	SSP SWP T	0.60		1
9	ZANKER #2 TAP		115.00	115.00	SSP SWP T	0.72		1
10	AERA ENERGY TAP		70.00	60.00	SSP SWP	0.35		1
11	ANTELOPE TAP		70.00	70.00	SSP SWP	4.33		1
12	ARBURUA TAP		70.00	70.00	SWP T	3.57		1
13	ARCO	CARNERAS	70.00	70.00	SSP SWP	17.97		1
14	ARCO	CHOLAME	70.00	70.00	SSP SWP	26.72		1
15	ARCO	POLONIO PASS PP	70.00	70.00	SSP SWP	21.27		1
16	ARCO	TULARE LAKE	70.00	70.00	SSP SWP	16.11		1
17	ARCO	TWISSELMAN	70.00	70.00	SSP SWP	6.52		1
18	ARMSTRONG TAP		70.00	70.00	SWP	0.44		1
19	ATASCADERO	CAYUCOS	70.00	70.00	OTHER SSP	11.80		1
20	ATASCADERO	SAN LUIS OBISPO	70.00	70.00	SSP OTHER	15.47		1
21	AUBERRY TAP		70.00	70.00	SSP SWP	2.27		1
22	AVENAL TAP		70.00	70.00	OTHER 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	OTHER SSP	18.84		1
27	BONITA TAP		70.00	70.00	SSP SWP	3.04		1
28	BORDEN	COPPERMINE	70.00	70.00	OTHER SSP	19.95		1
29	BORDEN	GLASS	70.00	70.00	SSP SWP	6.62		1
30	BORDEN	MADERA #2	70.00	70.00	OTHER SSP	5.81		1
31	BORDEN	MADERA #1	70.00	70.00	SSP SWP	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 JCT	MARIPOSA TAP	70.00	70.00	SSP SWP T	7.78		1
35	CADET TAP		70.00	70.00	SWP	0.12		1
36					TOTAL	36,892.15		1,445

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1	CALIFORNIA AVE	KEARNEY	70.00	70.00	SWP	3.20		1
2	CAMDEN	KINGSBURG	70.00	70.00	SSP SWP T	14.91		1
3	CANANDAIGUA WINERY		70.00	70.00	SWP	0.29		1
4	CARNATION TAP		70.00	70.00	SSP SWP	0.61		1
5	CARNERAS	TAFT	70.00	70.00	OTHER SSP	34.92		1
6	CARUTHERS	LEMOORE NAS-CAMDEN	70.00	70.00	SSP SWP	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	OTHER 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	OTHER SSP	8.61		1
14	COALINGA #1	SAN MIGUEL	70.00	70.00	SSP SWP T	38.01		1
15	COALINGA COGEN TAP		70.00	70.00	SSP SWP	4.91		1
16	COPPERMINE	TIVY VALLEY	70.00	70.00	OTHER SSP	24.01		1
17	COPUS	OLD RIVER	70.00	70.00	SSP SWP	19.61		1
18	CORCORAN	ANGIOLA	70.00	70.00	SWP	8.96		1
19	CORCORAN	GUERNSEY	70.00	70.00	SSP SWP	13.57		1
20	DERRICK TAP		70.00	70.00	SWP	0.85		1
21	DINOSAUR POINT TAP		70.00	70.00	OTHER SSP	2.00		1
22	DINUBA	OROSI	70.00	70.00	SSP SWP	9.83		1
23	DINUBA ENERGY TAP		70.00	70.00	SWP	3.16		1
24	DIVIDE	VANDENBERG #1	70.00	70.00	SWP	6.64		1
25	DIVIDE	VANDENBERG #2	70.00	70.00	OTHER SWP	6.57		1
26	DIVIDE	ZACA-LOMPOC (12KV)	70.00	70.00	SWP	10.55		1
27	DUNLAP TAP		70.00	70.00	SSP SWP	16.21		1
28	EISEN TAP		70.00	70.00	SWP	1.86		1
29	EL PECO TAP		70.00	70.00	OTHER SWP	3.02		1
30	EMIDIO TAP		70.00	70.00	SWP	3.07		1
31	EXCHEQUER	MARIPOSA	70.00	70.00	SSP SWP T	19.30		1
32	EXCHEQUER	YOSEMITE	70.00	70.00	OTHER SSP	34.91		1
33	FIVE POINTS SW STA	HURON-GATES	70.00	70.00	SSP SWP T	19.78		1
34	FRESNO COGEN (AGRICO)		70.00	70.00	SWP	3.17		1
35	FRIANT	COPPERMINE	70.00	70.00	SWP	8.30		1
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1	FRUITVALE TAP		70.00	70.00	SWP T	0.12		1
2	GARDNER TAP		70.00	70.00	SWP	3.77		1
3	GATES	JAYNE SW STA	70.00	70.00	SSP SWP	0.68		1
4	GATES	COALINGA #2	70.00	70.00	SSP SWP	17.26		1
5	GATES	HURON	70.00	70.00	SSP SWP T	4.50		1
6	GATES	TULARE LAKE	70.00	70.00	OTHER SSP	18.34		1
7	GIFFEN TAP		70.00	70.00	SSP SWP	4.95		1
8	GRAPEVINE TAP		70.00	70.00	SWP	0.14		1
9	GUERNSEY	HENRIETTA	70.00	70.00	SSP SWP	18.44		1
10	GWF	HENRIETTA	70.00	70.00	SWP	0.12		1
11	GWF HANFORD COGEN		70.00	70.00	OTHER SWP	0.32		1
12	HAAS	WOODCHUCK	70.00	70.00	SSP SWP	6.79		1
13	HARDWICK TAP		70.00	70.00	SWP	2.74		1
14	HELM	KERMAN	70.00	70.00	SSP SWP	13.25		1
15	HELM	STROUD SW STA	70.00	70.00	SWP	4.79		1
16	HELM	STROUD	70.00	70.00	SWP	7.43		1
17	HENRIETTA	LEMOORE	70.00	70.00	SSP SWP	9.37		1
18	HENRIETTA	LEMOORE NAS	70.00	70.00	SSP SWP	1.69		1
19	HENRIETTA	KENT SW STA	70.00	70.00	SSP SWP	1.47		1
20	HERDLYN	TRACY	70.00	70.00	SWP	2.06		1
21	JAYNE SW STA	COALINGA	70.00	70.00	SSP SWP	11.81		1
22	KEARNEY	BIOLA	70.00	70.00	SSP SWP T	19.13		1
23	KEARNEY	BOWLES	70.00	70.00	SSP SWP	9.29		1
24	KEARNEY	CARUTHERS	70.00	70.00	SWP	12.05		1
25	KEARNEY	KERMAN	70.00	70.00	SSP SWP	10.98		1
26	KEARNEY ALTERNATE TIE		70.00	70.00	SWP T	0.30		1
27	KEARNEY TIE		70.00	70.00	SWP T	0.15		1
28	KELLEY TAP		70.00	70.00	SWP	2.79		1
29	KENT SW STA	TULARE LAKE	70.00	70.00	SSP SWP T	15.93		1
30	KERN	FRUITVALE	70.00	70.00	SWP T	0.16		1
31	KERN	KERN OIL-FAMOSO	70.00	70.00	SSP SWP	24.69		1
32	KERN	MAGUNDEN	70.00	70.00	SSP SWP	20.61		1
33	KERN	OLD RIVER #1	70.00	70.00	SSP SWP	11.94		1
34	KERN	OLD RIVER #2	70.00	70.00	SSP SWP	23.07		1
35	KERN CANYON	MAGUNDEN-WEEDPATCH	70.00	70.00	SSP SWP T	20.64		1
36					TOTAL	36,892.15		1,445

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	KETTLEMAN HILLS TAP		70.00	70.00	SSP SWP	1.02		1
2	KINGSBURG	LEMOORE	70.00	70.00	OTHER SSP	27.50		1
3	LAS PERILLAS TAP		70.00	70.00	SWP	0.39		1
4	LEPRINO TAP		70.00	70.00	SWP	0.47		1
5	LIGHTNER TAP		70.00	70.00	SWP	3.06		1
6	LIVINGSTON	LIVINGSTON JCT	70.00	70.00	SSP SWP	23.36		1
7	LOS BANOS	MERCY SPRINGS SW STA	70.00	70.00	SSP SWP T	14.73		1
8	LOS BANOS	LIVINGSTON JCT-CANAL	70.00	70.00	SSP SWP T	14.29		1
9	LOS BANOS	O'NEILL PGP	70.00	70.00	SSP SWP	3.88		1
10	LOS BANOS	PACHECO	70.00	70.00	OTHER SSP	20.78		1
11	LOST HILLS TAP		70.00	70.00	SSP SWP	2.89		1
12	MARICOPA	COPUS	70.00	70.00	SSP SWP	7.86		1
13	MCFARLAND TAP		70.00	70.00	SWP	5.99		1
14	MCSWAIN TAP		70.00	70.00	SWP T	1.37		1
15	MENDOTA	SAN JOAQUIN-HELM	70.00	70.00	SSP SWP	26.97		1
16	MENDOTA BIOMASS TAP		70.00	70.00	SSP SWP	3.84		1
17	MERCED	MERCED FALLS	70.00	70.00	OTHER SSP	20.93		1
18	MERCED #1		70.00	70.00	SSP SWP T	39.88		1
19	MERCED FALLS	EXCHEQUER	70.00	70.00	SSP T	6.29		1
20	MERCY SPRINGS SW STA	CANAL-ORO LOMA	70.00	70.00	SSP SWP	23.32		1
21	MOCO TAP		70.00	70.00	SWP	1.64		1
22	MUSTANG TAP		70.00	70.00	SWP	0.71		1
23	OIL CITY TAP		70.00	70.00	SWP	0.05		1
24	ORO LOMA	CANAL #1	70.00	70.00	SSP SWP T	24.56		1
25	ORO LOMA	MENDOTA	70.00	70.00	SSP SWP T	29.58		1
26	PASO ROBLES	TEMPLETON	70.00	70.00	OTHER SSP	4.90		1
27	PENN ZIER TAP		70.00	70.00	SWP	4.99		1
28	PENTLAND TAP		70.00	70.00	SWP	0.55		1
29	REEDLEY	DINUBA #1	70.00	70.00	SSP SWP	7.70		1
30	REEDLEY	OROSI	70.00	70.00	SSP SWP	10.89		1
31	RESERVE OIL TAP		70.00	70.00	SWP	0.58		1
32	RIO BRAVO HYDRO		70.00	70.00	SWP	0.24		1
33	RIVER ROCK TAP		70.00	70.00	SSP SWP	1.21		1
34	ROSE TAP		70.00	70.00	SWP	0.31		1
35	SAN BERNARD	TEJON	70.00	70.00	SSP SWP T	6.96		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/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	SAN LUIS OBISPO	CAYUCOS	70.00	70.00	SSP SWP T	23.39		1
2	SAN LUIS OBISPO	SANTA MARIA *	70.00	70.00	SSP SWP	13.33		1
3	SAN MIGUEL	PASO ROBLES	70.00	70.00	SWP	9.92		1
4	SANGER	CALIFORNIA AVE #1	70.00	70.00	SSP SWP	9.23		1
5	SCHINDLER	COALINGA #2	70.00	70.00	SSP SWP	17.26		1
6	SCHINDLER	FIVE POINTS SW STA	70.00	70.00		1.70		1
7	SEMITROPIC	WASCO	70.00	70.00	SSP SWP T	6.32		1
8	SOLAR TANNEHILL TAP		70.00	70.00	SWP	2.65		1
9	STONE CORRAL TAP		70.00	70.00	OTHER SSP	7.57		1
10	STROUD SW STA	SCHINDLER	70.00	70.00	SWP	10.71		1
11	STROUD SW STA	STROUD	70.00	70.00	SWP	3.81		1
12	SYCAMORE TAP		70.00	70.00	SWP	2.04		1
13	TAFT	CUYAMA #1	70.00	70.00	SSP SWP	19.25		1
14	TAFT	CUYAMA #2	70.00	70.00	SSP SWP	18.75		1
15	TAFT	ELK HILLS	70.00	70.00	SSP SWP T	12.39		1
16	TAFT	MARICOPA	70.00	70.00	SSP SWP T	5.98		1
17	TECUYA TAP		70.00	70.00	SSP SWP	1.91		1
18	TEJON	LEBEC	70.00	70.00	SSP SWP	13.00		1
19	TEMPLETON	ATASCADERO	70.00	70.00	SSP SWP	8.82		1
20	TEXACO (LOST HILLS) TAP		70.00	70.00	SWP	0.01		1
21	TEXACO BASIC SCHOOL		70.00	70.00	SWP	0.75		1
22	TEXACO BUENA VISTA		70.00	70.00	SWP	0.10		1
23	TIVY VALLEY	REEDLEY	70.00	70.00	SWP	12.30		1
24	TORNADO TAP		70.00	70.00	SWP	0.06		1
25	TULE	SPRINGVILLE	70.00	70.00	OTHER SSP	15.24		1
26	WASCO	FAMOSO	70.00	70.00	SSP SWP T	7.12		1
27	WEEDPATCH	SAN BERNARD	70.00	70.00	SSP SWP	9.27		1
28	WEEDPATCH	WELLFIELD	70.00	70.00	SSP SWP	5.80		1
29	WESIX TAP		70.00	70.00	SWP	2.51		1
30	WESTLANDS TAP		70.00	70.00	SWP	1.07		1
31	WHEELER RIDGE	LAKEVIEW	70.00	70.00	SSP SWP	7.51		1
32	WHEELER RIDGE	SAN BERNARD	70.00	70.00	SWP	5.88		1
33	WHEELER RIDGE	TEJON	70.00	70.00	SWP T	5.01		1
34	WHEELER RIDGE	WEEDPATCH	70.00	70.00	SSP SWP	22.42		1
35	WISHON	COPPERMINE	70.00	70.00	SSP SWP T	19.99		1
36					TOTAL	36,892.15		1,445

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/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	WISHON	SAN JOAQUIN #3	70.00	70.00	OTHER SSP	7.68		1
2	WRIGHT TAP		70.00	70.00	OTHER SWP	1.18		1
3	YANKE (NORTH FORK) TAP		70.00	70.00	SWP	0.58		1
4	ALMADEN	LOS GATOS	60.00	60.00	SSP SWP	6.38		1
5	ALMENDRA JCT	NICOLAUS	60.00	60.00	SSP SWP	24.90		1
6	AMFOR TAP		60.00	60.00	SWP	1.08		1
7	ARBUCKLE TAP		60.00	60.00	SSP SWP	0.82		1
8	ARCATA	HUMBOLDT	60.00	60.00	SSP SWP	7.28		1
9	AUBURN TAP		60.00	60.00	SSP SWP	0.75		1
10	BAIR	COOLEY LANDING #1	60.00	60.00	SSP SWP T	5.57		1
11	BAIR	COOLEY LANDING #2	60.00	60.00	SSP SWP T	5.61		1
12	BASALT #1 TAP		60.00	60.00	SWP T T	1.18		1
13	BEALE AFB (WAPA) #1 TAP		60.00	60.00	SSP SWP	0.11		1
14	BEALE AFB (WAPA) #2 TAP		60.00	60.00	SSP SWP	0.14		1
15	BELLE HAVEN #1 TAP		60.00	60.00	SSP SWP T	0.45		1
16	BELLE HAVEN #2 TAP		60.00	60.00	SSP SWP T	0.40		1
17	BIXLER TAP		60.00	60.00	SWP	0.55		1
18	BLUE CHIP MILLING TAP		60.00	60.00	SWP	0.42		1
19	BLUE LAKE TAP		60.00	60.00	SSP SWP	3.70		1
20	BRIDGEVILLE	GARBERVILLE	60.00	60.00	OTHER SSP	36.16		1
21	BRIONES TAP		60.00	60.00	SSP SWP	7.00		1
22	BUENA VISTA BIOMASS		60.00	60.00	SSP SWP	1.02		1
23	BURNEY TAP		60.00	60.00	SSP SWP	1.09		1
24	BURNS	LONE STAR #1	60.00	60.00	SSP SWP	5.42		1
25	BURNS	LONE STAR #2	60.00	60.00	OTHER SSP	6.34		1
26	BUTTE	CHICO #1	60.00	60.00	SWP	0.79		1
27	BUTTE	CHICO #2	60.00	60.00	SWP	0.74		1
28	BUTTE	ESQUON	60.00	60.00	SSP SWP	9.87		1
29	CACHE SLOUGH TAP		60.00	60.00	SSP SWP	6.85		1
30	CALVO TAP		60.00	60.00	SWP	0.54		1
31	CAPE HORN TAP		60.00	60.00	SSP SWP	0.31		1
32	CARBONA #2 TAP		60.00	60.00	SWP	5.64		1
33	CARIBOU	PLUMAS JCT	60.00	60.00	OTHER SSP	21.25		1
34	CARIBOU	WESTWOOD	60.00	60.00	SWP	21.06		1
35	CARIBOU #2		60.00	60.00	SSP SWP	42.19		1
36					TOTAL	36,892.15		1,445

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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	CASCADE	BENTON-DESCHUTES	60.00	60.00	OTHER SSP	15.98		1
2	CENTERVILLE	TABLE MTN	60.00	60.00	SSP SWP	21.51		1
3	CENTERVILLE	TABLE MTN-OROVILLE	60.00	60.00	SSP SWP T	26.11		1
4	CHICO A	DAYTON RD	60.00		SWP	0.75		1
5	CHRISTIE	FRANKLIN #1	60.00	60.00	SSP SWP	5.01		1
6	CHRISTIE	FRANKLIN #2	60.00	60.00	SSP SWP	5.11		1
7	CHRISTIE	WILLOW PASS	60.00	60.00	OTHER SSP	15.93		1
8	CHUALAR TAP		60.00	60.00	SWP	1.43		1
9	CIC TAP		60.00	60.00	SWP	0.13		1
10	CISCO GROVE TAP		60.00	60.00	SWP	0.34		1
11	CLAY	MARTEL	60.00	60.00	OTHER SSP	21.49		1
12	CLEAR LAKE	HOPLAND	60.00	60.00	OTHER SWP	11.54		1
13	CLEAR LAKE	KONOCTI	60.00	60.00	SSP SWP	10.95		1
14	CLOVER CREEK TAP		60.00	60.00	SWP	0.02		1
15	COBURN	BASIC ENERGY	60.00	60.00	SWP	3.14		1
16	COBURN	OIL FIELDS #1	60.00	60.00	SSP SWP	29.46		1
17	COBURN	OIL FIELDS #2	60.00	60.00	SSP SWP	31.05		1
18	COGENERATION NATIONAL		60.00	60.00	SWP	0.56		1
19	COLEMAN	COTTONWOOD	60.00	60.00	OTHER SSP	8.58		1
20	COLEMAN	RED BLUFF	60.00	60.00	SSP SWP	48.31		1
21	COLEMAN	SOUTH	60.00	60.00	SSP SWP	13.39		1
22	COLEMAN HATCHERY TAP		60.00	60.00	SWP	0.56		1
23	COLGATE	ALLEGHANY	60.00	60.00	OTHER SSP	24.55		1
24	COLGATE	CHALLENGE	60.00	60.00	OTHER SSP	13.04		1
25	COLGATE	GRASS VALLEY	60.00	60.00	OTHER SSP	13.17		1
26	COLGATE	PALERMO	60.00	60.00	OTHER SSP	22.65		1
27	COLGATE	SMARTVILLE #1	60.00	60.00	OTHER SSP	11.26		1
28	COLGATE	SMARTVILLE #2	60.00	60.00	SSP SWP	11.19		1
29	COLGATE PH	COLGATE SW STA	60.00	60.00	SSP	0.19		1
30	COLLINS PINE TAP		60.00	60.00	SWP	0.14		1
31	COLUSA JCT #1		60.00	60.00	SSP SWP	16.98		1
32	CONTRA COSTA	DU PONT	60.00	60.00	OTHER SWP	2.65		1
33	CONTRA COSTA	PITTSBURG	60.00	60.00	SSP SWP T	6.28		1
34	CONTRA COSTA	SHELL CHEMICAL#1(21KV)	60.00	60.00	SSP SWP T	9.55		1
35	CONTRA COSTA	BALFOUR	60.00	60.00	SSP SWP T	11.55		1
36					TOTAL	36,892.15		1,445

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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	COOLEY LANDING	LOS ALTOS	60.00	60.00	SSP SWP T	15.04		1
2	COOLEY LANDING	LOS ALTOS (I2KV)	60.00	60.00	SSP SWP T	1.41		1
3	COOLEY LANDING	STANFORD	60.00	60.00	SSP SWP	6.04		1
4	COOLEY LANDING	STANFORD	60.00	60.00	N/A	1.59		1
5	CORDELIA #1 TAP		60.00	60.00	SSP SWP	7.69		1
6	CORDELIA #2 TAP		60.00	60.00	OTHER SSP	6.87		1
7	CORDELIA INTERIM		60.00	60.00	SSP SWP	0.36		1
8	CORTINA #1		60.00	60.00	SSP SWP	26.29		1
9	CORTINA #2		60.00	60.00	OTHER SSP	26.61		1
10	CORTINA #3		60.00	60.00	SSP SWP	24.84		1
11	CORTINA #4		60.00	60.00	SSP SWP	45.24		1
12	COTTONWOOD	BENTON #1	60.00	60.00	SSP SWP T	15.53		1
13	COTTONWOOD	BENTON #2	60.00	60.00	OTHER SSP	14.68		1
14	COTTONWOOD	RED BLUFF	60.00	60.00	OTHER SSP	16.74		1
15	COTTONWOOD #1		60.00	60.00	SSP SWP T	48.27		1
16	COTTONWOOD #2		60.00	60.00	SSP SWP T	23.63		1
17	CROW CREEK SW STA	FRONTIER SOLAR PV	60.00	60.00	SSP	0.02		1
18	CROW CREEK SW STA	NEWMAN	60.00	60.00	SSP SWP	11.14		1
19	CROWS LANDING TAP		60.00	60.00	SWP	5.28		1
20	CRUSHER TAP		60.00	60.00	SWP	1.95		1
21	CRYSTAL SPRINGS TAP		60.00	60.00	SSP SWP T	0.28		1
22	DEAN FOODS TAP		60.00	60.00	SWP	0.51		1
23	DEER CREEK	DRUM	60.00	60.00	SSP SWP	6.24		1
24	DEL MAR	ATLANTIC #1	60.00	60.00	SSP SWP	2.78		1
25	DEL MAR	ATLANTIC #2	60.00	60.00	SSP SWP	4.45		1
26	DEL MAR	ATLANTIC #1	60.00	60.00	N/A	1.18		1
27	DEL MONTE	MONTEREY	60.00	60.00	SSP SWP	2.53		1
28	DEL MONTE	VIEJO	60.00	60.00	SSP SWP	7.92		1
29	DEL MONTE	FORT ORD #1	60.00	60.00	SSP SWP	6.13		1
30	DEL MONTE	FORT ORD #2	60.00	60.00	SSP SWP	5.61		1
31	DELTA	MTN GATE JCT	60.00	60.00	OTHER SWP	15.15		1
32	DESABLA	CENTERVILLE	60.00	60.00	OTHER SSP	5.86		1
33	DISTRICT 1001 TAP		60.00	60.00	SWP	1.47		1
34	DISTRICT 1500 TAP		60.00	60.00	SSP SWP	3.61		1
35	DIXON	VACA #1	60.00	60.00	SSP SWP T	18.35		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	DIXON	VACA #2	60.00	60.00	SSP SWP T	26.77		1
2	DRUM	GRASS VALLEY-WEIMAR	60.00	60.00	SSP SWP	31.17		1
3	DRUM	SPAULDING	60.00	60.00	SSP SWP	9.36		1
4	DU PONT TAP		60.00	60.00	SWP T	0.52		1
5	EAST DUBLIN (BART) TAP		60.00	60.00	SWP	0.04		1
6	EEL RIVER TAP		60.00	60.00	SSP SWP T	2.31		1
7	ELK	GUALALA	60.00	60.00	OTHER SSP	29.01		1
8	ELK CREEK TAP		60.00	60.00	SSP SWP	20.44		1
9	ENCINAL TAP		60.00	60.00	SSP SWP	1.43		1
10	ESSEX JCT	ARCATA-FAIRHAVEN	60.00	60.00	OTHER SSP	16.08		1
11	ESSEX JCT	ORICK	60.00	60.00	OTHER SSP	31.29		1
12	EUREKA	STA A	60.00	60.00	SWP	0.22		1
13	EVERGREEN	ALMADEN	60.00	60.00	SWP	4.96		1
14	EVERGREEN	MABURY	60.00	60.00	SWP	5.48		1
15	FAIRHAVEN	HUMBOLDT	60.00	60.00	SSP SWP T	15.56		1
16	FAIRHAVEN #1		60.00	60.00	SWP	0.41		1
17	FAIRHAVEN POWER CO		60.00	60.00	SWP	0.55		1
18	FITCH MTN #1 TAP		60.00	60.00	SWP	0.87		1
19	FITCH MTN #2 TAP		60.00	60.00	SWP	0.07		1
20	FORKS OF THE BUTTE TAP		60.00	60.00	SWP	0.20		1
21	FORT BRAGG	ELK	60.00	60.00	SSP SWP	24.02		1
22	FORT ROSS	GUALALA	60.00	60.00	OTHER SSP	29.76		1
23	FORT SEWARD TAP		60.00	60.00	SSP SWP	7.70		1
24	FRENCH MEADOWS	MIDDLE FORK	60.00	60.00	OTHER SSP	13.19		1
25	FRESH EXPRESS TAP		60.00	60.00	SWP	0.56		1
26	FRUITLAND TAP		60.00	60.00	SSP SWP	4.26		1
27	FULTON	WINDSOR	60.00	60.00	SSP SWP	6.59		1
28	FULTON	CALISTOGA	60.00	60.00	OTHER SSP	64.60		1
29	FULTON	HOPLAND	60.00	60.00	SSP SWP	41.27		1
30	FULTON	MOLINO-COTATI	60.00	60.00	SSP SWP	20.52		1
31	FULTON	MOLINO-COTATI	60.00	60.00	SSP SWP	0.35		1
32	GARBERVILLE	LAYTONVILLE	60.00	60.00	OTHER SSP	40.03		1
33	GARCIA TAP		60.00	60.00	SSP SWP	3.04		1
34	GLENN #1		60.00	60.00	SSP SWP	33.37		1
35	GLENN #2		60.00	60.00	SSP SWP	34.69		1
36					TOTAL	36,892.15		1,445

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	GLENN #3		60.00	60.00	SSP SWP	28.53		1
2	GLENN #4		60.00	60.00	SSP SWP	12.42		1
3	GLENN #5		60.00	60.00	SSP SWP	7.41		1
4	GOLD HILL #1		60.00	60.00	OTHER SSP	27.85		1
5	GONZALES #1 TAP		60.00	60.00	SWP	0.20		1
6	GONZALES #2 TAP		60.00	60.00	SWP	0.30		1
7	GRANITE ROCK TAP		60.00	60.00	SWP	2.39		1
8	GREEN VALLEY	WATSONVILLE	60.00	60.00	SSP SWP	4.74		1
9	GREENLEAF #2 TAP		60.00	60.00	SWP	0.62		1
10	GRONEMEYER TAP		60.00	60.00	SWP	0.83		1
11	GUSTINE #1 TAP		60.00	60.00	SSP SWP	7.56		1
12	GUSTINE #2 TAP		60.00	60.00	SWP	4.44		1
13	GWF #4 TAP		60.00	60.00	SWP T	0.25		1
14	HALSEY	PLACER	60.00	60.00	SSP SWP	4.94		1
15	HAMILTON BRANCH	CHESTER	60.00	60.00	OTHER SSP	12.27		1
16	HAMMER	COUNTRY CLUB	60.00	60.00	SSP SWP	8.82		1
17	HARRINGTON TAP		60.00	60.00	SWP	0.53		1
18	HARTLEY	CLEARLAKE	60.00	60.00	SSP SWP	6.66		1
19	HAT CREEK #1	PIT #1	60.00	60.00	OTHER SSP	6.03		1
20	HAT CREEK #1	WESTWOOD	60.00	60.00	OTHER SSP	55.87		1
21	HEADGATE TAP		60.00	60.00	SWP	0.97		1
22	HEALDSBURG #1 TAP		60.00	60.00	SWP	0.25		1
23	HEALDSBURG #2 TAP		60.00	60.00	SSP SWP	0.16		1
24	HERDLYN	BALFOUR	60.00	60.00	SSP SWP	20.50		1
25	HILLSDALE JCT	HALF MOON BAY	60.00	60.00	OTHER SSP	6.82		1
26	HUMBOLDT	EUREKA	60.00	60.00	SSP SWP	4.70		1
27	HUMBOLDT	MAPLE CREEK	60.00	60.00	OTHER SSP	14.13		1
28	HUMBOLDT #1		60.00	60.00	SSP SWP T	11.05		1
29	HUMBOLDT BAY	EUREKA	60.00	60.00	SSP SWP	5.61		1
30	HUMBOLDT BAY	HUMBOLDT #1	60.00	60.00	SSP SWP	8.34		1
31	HUMBOLDT BAY	HUMBOLDT #2	60.00	60.00	SSP SWP T	6.45		1
32	HUMBOLDT BAY	RIO DELL JCT	60.00	60.00	OTHER SSP	18.40		1
33	IGNACIO	BOLINAS #1	60.00	60.00	SSP SWP	15.06		1
34	IGNACIO	ALTO	60.00	60.00	SSP SWP T	23.91		1
35	IGNACIO	ALTO-SAUSALITO #1	60.00	60.00	SSP SWP T	17.83		1
36					TOTAL	36,892.15		1,445

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1	IGNACIO	ALTO-SAUSALITO #2	60.00	60.00	SWP T	17.84		1
2	IGNACIO	BOLINAS #2	60.00	60.00	OTHER SSP	28.22		1
3	INDUSTRIAL TAP		60.00	60.00	SWP	0.97		1
4	IONE TAP		60.00	60.00	SSP SWP	4.09		1
5	IUKA TAP		60.00	60.00	SWP	0.49		1
6	JANES CREEK TAP		60.00	60.00	SSP SWP	1.78		1
7	JEFFERSON	HILLSDALE JCT	60.00	60.00	SSP SWP T	14.72		1
8	JEFFERSON	LAS PULGAS	60.00	60.00	SSP SWP	6.00		1
9	JEFFERSON	STANFORD	60.00	60.00	SSP SWP	7.64		1
10	JEFFERSON	STANFORD	60.00	60.00	N/A	1.52		1
11	JEFFERSON	LAS PULGAS	60.00	60.00	N/A	0.18		1
12	JEFFERSON #1		60.00	60.00	SSP SWP T	9.05		1
13	JENNINGS TAP		60.00	60.00	SWP	0.16		1
14	JOLON TAP		60.00	60.00	SSP SWP	15.87		1
15	KASSON	CARBONA	60.00	60.00	SSP SWP T	7.32		1
16	KASSON	BANTA #1	60.00	60.00	SWP	1.05		1
17	KASSON	LOUISE	60.00	60.00	SSP SWP T	8.79		1
18	KASSON #1		60.00	60.00	SSP SWP	0.19		1
19	KESWICK	CASCADE	60.00	60.00	SSP SWP	9.35		1
20	KESWICK	TRINITY	60.00	60.00	OTHER SSP	30.42		1
21	KILARC	CEDAR CREEK	60.00	60.00	SSP SWP	13.33		1
22	KILARC	DESCHUTES	60.00	60.00	SSP SWP	27.28		1
23	KILARC	VOLTA TIE	60.00	60.00	SWP T	1.94		1
24	KING CITY	COBURN #1	60.00	60.00	OTHER SSP	21.91		1
25	KING CITY	COBURN #2	60.00	60.00	SSP SWP	15.79		1
26	KONOCTI	MIDDLETOWN	60.00	60.00	OTHER SSP	19.87		1
27	KONOCTI	EAGLE ROCK	60.00	60.00	SSP SWP	9.66		1
28	LAGUNA TAP		60.00	60.00	SSP SWP	1.68		1
29	LAGUNITAS TAP		60.00	60.00	SWP	0.60		1
30	LAKEVILLE	PETALUMA C	60.00	60.00	SSP SWP	5.31		1
31	LAKEVILLE #1		60.00	60.00	OTHER SSP	11.16		1
32	LAKEVILLE #2		60.00	60.00	SSP SWP T	21.62		1
33	LAS POSITAS	VASCO	60.00	60.00	SSP SWP	1.50		1
34	LAURELES	OTTER	60.00	60.00	SSP SWP	15.56		1
35	LAYTONVILLE	COVELO	60.00	60.00	OTHER SSP	16.08		1
36					TOTAL	36,892.15		1,445

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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	LAYTONVILLE	WILLITS	60.00	60.00	OTHER SSP	23.16		1
2	LEE TAP		60.00	60.00	SWP	8.26		1
3	LIMESTONE TAP		60.00	60.00	SWP	1.73		1
4	LIVERMORE	LAS POSITAS	60.00	60.00	SSP SWP	3.63		1
5	LOCKEFORD	INDUSTRIAL	60.00	60.00	SWP	6.03		1
6	LOCKEFORD	LODI #2	60.00	60.00	SSP SWP	9.41		1
7	LOCKEFORD	LODI #3	60.00	60.00	SSP SWP	15.42		1
8	LOCKEFORD #1		60.00	60.00	OTHER SSP	12.85		1
9	LODI	INDUSTRIAL	60.00	60.00	SSP SWP	0.97		1
10	LONE STAR TAP		60.00	60.00	SWP	1.18		1
11	LOS COCHES TAP		60.00	60.00	SWP	1.33		1
12	LOUISIANA PACIFIC		60.00	60.00	SWP	0.16		1
13	LP FLAKEBOARD TAP		60.00	60.00	SWP	0.51		1
14	LYOTH TAP		60.00	60.00	SSP SWP	1.34		1
15	MANTECA	LOUISE	60.00	60.00	SSP SWP	12.53		1
16	MANTECA #1		60.00	60.00	SSP SWP	34.52		1
17	MAPLE CREEK	HOOPA	60.00	60.00	OTHER SSP	29.13		1
18	MARSH TAP		60.00	60.00	SWP	3.97		1
19	MARTIN	SNEATH LANE	60.00	60.00	SSP SWP	7.19		1
20	MCDONALD TAP		60.00	60.00	OTHER SSP	5.88		1
21	MENDOCINO	HARTLEY	60.00	60.00	OTHER SSP	23.18		1
22	MENDOCINO	PHILO JCT-HOPLAND	60.00	60.00	SSP SWP	23.55		1
23	MENDOCINO	WILLITS	60.00	60.00	SSP SWP	14.52		1
24	MENDOCINO	WILLITS-FORT BRAGG	60.00	60.00	OTHER SSP	43.77		1
25	MENDOCINO #1		60.00	60.00	SSP SWP	7.48		1
26	MENLO TAP		60.00	60.00	SWP	0.36		1
27	MIDDLE FORK #1		60.00	60.00	OTHER SSP	9.43		1
28	MIDDLE RIVER TAP		60.00	60.00	SSP SWP	7.02		1
29	MILLBRAE	SNEATH LANE	60.00	60.00	SSP SWP T	6.49		1
30	MONTA VISTA	BURNS	60.00	60.00	OTHER SSP	18.06		1
31	MONTA VISTA	LOS ALTOS	60.00	60.00	SSP SWP	7.13		1
32	MONTA VISTA	LOS GATOS	60.00	60.00	SWP	10.88		1
33	MONTA VISTA	PERMANENTE	60.00	60.00	SWP T	1.19		1
34	MONTE RIO	FORT ROSS	60.00	60.00	OTHER SSP	14.30		1
35	MONTE RIO	FULTON	60.00	60.00	OTHER SSP	22.56		1
36					TOTAL	36,892.15		1,445

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	MTN GATE JCT	CASCADE	60.00	60.00	OTHER SWP	6.57		1
2	MTN GATE TAP		60.00	60.00	SWP	0.70		1
3	MTN QUARRIES TAP		60.00	60.00	SSP SWP	2.63		1
4	MULE CREEK TAP		60.00	60.00	SSP	0.01		1
5	NARROWS #1 TAP		60.00	60.00	OTHER SWP	2.65		1
6	NARROWS #2 TAP		60.00	60.00	OTHER SSP	3.10		1
7	NAVY LAB TAP		60.00	60.00	SWP	0.19		1
8	NEW HOGAN TAP		60.00	60.00	SWP	2.21		1
9	NEWARK	DECOTO	60.00	60.00	SSP SWP T	6.28		1
10	NEWARK	LIVERMORE	60.00	60.00	OTHER SSP	19.05		1
11	NEWARK	VALLECITOS	60.00	60.00	SSP SWP T	12.39		1
12	NEWARK	SIERRA PAPERBOARD TAP	60.00	60.00	SWP	0.29		1
13	NICOLAUS	CATLETT JCT	60.00	60.00	SSP SWP T	38.75		1
14	NICOLAUS	MARYSVILLE	60.00	60.00	OTHER SSP	18.74		1
15	NICOLAUS	PLAINFIELD	60.00	60.00	SSP SWP T	30.63		1
16	NICOLAUS	WILKINS SLOUGH	60.00	60.00	OTHER SSP	42.72		1
17	OAK PARK TAP		60.00	60.00	SSP SWP	0.87		1
18	OILFIELDS	SARGENT CANYON	60.00	60.00	SSP SWP	2.02		1
19	OILFIELDS	SALINAS RIVER	60.00	60.00	SWP	1.46		1
20	ORO FINO TAP		60.00	60.00	SWP	1.30		1
21	OXBOW TAP		60.00	60.00	SSP SWP	0.15		1
22	PACIFIC ETHANOL TAP		60.00	60.00	SWP	0.68		1
23	PACIFIC LUMBER (SCOTIA)		60.00	60.00	OTHER SWP	0.52		1
24	PACIFIC OROVILLE POWER		60.00	60.00	SWP	0.78		1
25	PALERMO	OROVILLE #1	60.00	60.00	SWP	6.97		1
26	PALERMO	OROVILLE #2	60.00	60.00	SSP SWP T	10.13		1
27	PARDEE #1 TAP		60.00	60.00	OTHER SWP	4.33		1
28	PARDEE #2 TAP		60.00	60.00	SWP	0.09		1
29	PARKS TAP		60.00	60.00	SWP	0.45		1
30	PEACHTON	PEASE	60.00	60.00	SSP SWP	16.34		1
31	PEASE	HARTER	60.00	60.00	SSP SWP	15.88		1
32	PEASE	MARYSVILLE-HARTER	60.00	60.00	SSP SWP	10.29		1
33	PERMANENTE #1 TAP		60.00	60.00	SWP	0.31		1
34	PERMANENTE #2 TAP		60.00	60.00	SSP SWP	0.51		1
35	PHILO JCT	ELK	60.00	60.00	SSP SWP	37.26		1
36					TOTAL	36,892.15		1,445

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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)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	PINE GROVE TAP		60.00	60.00	SWP	2.67		1
2	PIT #1	HAT CREEK #2-BURNEY	60.00	60.00	SSP SWP T	12.96		1
3	PIT #1	MCARTHUR	60.00	60.00	SWP	7.33		1
4	PITTSBURG #1 TAP (NO		60.00	60.00	SSP SWP	1.15		1
5	PITTSBURG #2 TAP		60.00	60.00	SSP SWP	1.19		1
6	PLACER	DEL MAR	60.00	60.00	SSP SWP	10.81		1
7	PLUMAS	SIERRA TAP	60.00	60.00	SWP	0.75		1
8	PORT COSTA BRICK TAP		60.00	60.00	SSP SWP	1.90		1
9	POTTER VALLEY	MENDOCINO	60.00	60.00	SSP SWP T	10.94		1
10	POTTER VALLEY	WILLITS	60.00	60.00	OTHER SSP	13.16		1
11	RADUM	LIVERMORE	60.00	60.00	SSP SWP	4.66		1
12	RADUM	VALLECITOS	60.00	60.00	OTHER SSP	10.62		1
13	RED BANK TAP		60.00	60.00	SSP SWP	0.68		1
14	RIO DELL JCT	BRIDGEVILLE	60.00	60.00	OTHER SSP	21.25		1
15	RIO DELL TAP		60.00	60.00	OTHER SSP	5.36		1
16	ROBERTSON TAP		60.00	60.00	SSP SWP	0.82		1
17	ROLLINS TAP		60.00	60.00	SSP SWP	0.73		1
18	ROUGH & READY TAP		60.00	60.00	SSP SWP	0.95		1
19	SALADO	CROW CREEK SW STA	60.00	60.00	SSP SWP	3.77		1
20	SALADO	NEWMAN #2	60.00	60.00	SSP SWP	21.57		1
21	SALINAS	FORT ORD #1	60.00	60.00	OTHER SSP	10.22		1
22	SALINAS	FIRESTONE #1	60.00	60.00	SSP SWP	6.18		1
23	SALINAS	FIRESTONE #2	60.00	60.00	SSP SWP	17.21		1
24	SALINAS	LAGUNITAS	60.00	60.00	SWP	5.81		1
25	SALINAS	LAURELES	60.00	60.00	SSP SWP	27.46		1
26	SALINAS	FORT ORD #2	60.00	60.00	SSP SWP T	10.12		1
27	SALMON CREEK TAP		60.00	60.00	SSP SWP	10.51		1
28	SAN ANDREAS (CCSF) TAP		60.00	60.00	SSP SWP	0.39		1
29	SAN ARDO TAP		60.00	60.00	SSP SWP	0.34		1
30	SAN BRUNO TAP		60.00	60.00	SSP SWP	1.13		1
31	SAN MATEO	BAIR	60.00	60.00	SSP SSP T	13.99		1
32	SAN MATEO	HILLSDALE JCT	60.00	60.00	OTHER SSP	6.89		1
33	SAN RAMON	RADUM	60.00	60.00	SWP	7.06		1
34	SEBASTIANI TAP		60.00	60.00	SWP	0.01		1
35	SENTER #1 TAP		60.00	60.00	SWP	0.23		1
36					TOTAL	36,892.15		1,445

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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	SEQUOIA TAP		60.00	60.00	SWP	0.59		1
2	SIERRA PAC IND (QUINCY)		60.00	60.00	SWP	0.17		1
3	SIERRA PINES LIMITED		60.00	60.00	SSP SWP	0.40		1
4	SIMPSON	KORBEL TAP	60.00	60.00	SWP	0.39		1
5	SLAC TAP		60.00	60.00	SWP	1.41		1
6	SMARTVILLE	CAMP FAR WEST	60.00	60.00	SSP SWP	17.81		1
7	SMARTVILLE	CAMP FAR WEST (12KV)	60.00	60.00	SSP SWP	7.15		1
8	SMARTVILLE	MARYSVILLE	60.00	60.00	SSP SWP	20.11		1
9	SMARTVILLE	NICOLAUS #1	60.00	60.00	OTHER SSP	29.60		1
10	SMARTVILLE	NICOLAUS #2	60.00	60.00	OTHER SSP	30.18		1
11	SMARTVILLE TAP		60.00	60.00	SWP	0.09		1
12	SNEATH LANE	HALF MOON BAY	60.00	60.00	OTHER SSP	15.41		1
13	SNEATH LANE	PACIFICA	60.00	60.00	OTHER SSP	3.26		1
14	SOLEDAD #1		60.00	60.00	SWP	15.50		1
15	SOLEDAD #2		60.00	60.00	OTHER SSP	18.86		1
16	SOLEDAD #3		60.00	60.00	SSP SWP	1.63		1
17	SOLEDAD #4		60.00	60.00	SSP SWP	6.08		1
18	SPAULDING	SUMMIT	60.00	60.00	OTHER SSP	19.65		1
19	SPAULDING #3	SPAULDING #1	60.00	60.00	SWP	1.09		1
20	STAGG	COUNTRY CLUB #1	60.00	60.00	SSP	2.43		1
21	STAGG	COUNTRY CLUB #2	60.00	60.00	SSP SWP	2.46		1
22	STAGG	HAMMER	60.00	60.00	SSP SWP	4.25		1
23	STANDARD #1 & #2 (12KV)		60.00	60.00	T	4.16		1
24	STANISLAUS RECOVERY		60.00	60.00	SWP	0.11		1
25	STAUFFER TAP		60.00	60.00	SSP SWP	0.58		1
26	STOCKTON	NEWARK	60.00	60.00	SSP SWP T	14.59		1
27	STOCKTON A	WEBER #1	60.00	60.00	SSP SWP	13.20		1
28	STOCKTON A	WEBER #2	60.00	60.00	SSP SWP	9.87		1
29	STOCKTON A	WEBER #3	60.00	60.00	SSP SWP	9.81		1
30	STOCKTON A #1		60.00	60.00	SSP SWP T	5.58		1
31	SUMIDEN WIRE PRODUCTS		60.00	60.00	SWP	0.19		1
32	SUNOL TAP		60.00	60.00	OTHER SWP	0.08		1
33	SUTTER HOME	SUTTER HOME SW STA	60.00	60.00	SSP	0.03		1
34	SUTTER HOME SW STA	LOCKEFORD-LODI	60.00	60.00	SSP SWP	29.74		1
35	SUTTER HOME SW STA	STAGG	60.00	60.00	SSP SWP	17.13		1
36					TOTAL	36,892.15		1,445

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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	TABLE MTN	PEACHTON	60.00	60.00	SSP SWP	14.84		1
2	TERMINOUS TAP		60.00	60.00	SWP	3.01		1
3	TEXACO TAP		60.00	60.00	SSP SWP	0.72		1
4	TOCALOMA TAP		60.00	60.00	SWP	1.03		1
5	TRAVIS TAP		60.00	60.00	SSP SWP	2.88		1
6	TRINIDAD TAP		60.00	60.00	SWP	1.34		1
7	TRINITY	MAPLE CREEK	60.00	60.00	OTHER SSP	55.45		1
8	TULUCAY	NAPA #1	60.00	60.00	SSP SWP T	9.72		1
9	TULUCAY	NAPA #2	60.00	60.00	SSP SWP T	3.93		1
10	ULTRA POWER TAP		60.00	60.00	SWP	1.17		1
11	UNION CHEMICAL TAP		60.00	60.00	SWP	1.04		1
12	URICH TAP		60.00	60.00	SWP	0.21		1
13	US WINDPOWER TAP		60.00	60.00	SWP	1.52		1
14	VACA	PLAINFIELD	60.00	60.00	SSP SWP T	29.83		1
15	VALLEY SPRINGS	CALAVERAS CEMENT	60.00	60.00	SSP SWP	7.91		1
16	VALLEY SPRINGS	MARTELL #1	60.00	60.00	SSP SWP	12.75		1
17	VALLEY SPRINGS	CLAY	60.00	60.00	OTHER SSP	17.30		1
18	VALLEY SPRINGS #1		60.00	60.00	OTHER SSP	27.27		1
19	VALLEY SPRINGS #2		60.00	60.00	OTHER SSP	25.65		1
20	VASCO	HERDLYN	60.00	60.00	OTHER SWP	10.97		1
21	VICTOR TAP		60.00	60.00	SSP SWP	0.06		1
22	VIEJO	MONTEREY	60.00	60.00	SSP SWP	2.28		1
23	VOLTA	DESCHUTES	60.00	60.00	SSP SWP	20.86		1
24	VOLTA	SOUTH	60.00	60.00	SSP SWP	4.86		1
25	WADHAM TAP		60.00	60.00	SWP	1.68		1
26	WASHOE TAP		60.00	60.00	SWP	1.04		1
27	WATERSHED TAP		60.00	60.00	SSP SWP T	0.28		1
28	WATSONVILLE	SALINAS	60.00	60.00	OTHER SSP	28.39		1
29	WEBER	FRENCH CAMP #1	60.00	60.00	SSP SWP T	6.07		1
30	WEBER	FRENCH CAMP #2	60.00	60.00	SSP SWP T	10.89		1
31	WEBER	MORMON JCT	60.00	60.00	SSP SWP	17.67		1
32	WEIMAR	HALSEY	60.00	60.00	SSP SWP	6.28		1
33	WEIMAR #1		60.00	60.00	OTHER SSP	13.98		1
34	WEST POINT	VALLEY SPRINGS	60.00	60.00	OTHER SSP	21.66		1
35	WESTINGHOUSE TAP		60.00	60.00	SWP T T	7.81		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	WILLOW PASS	CONTRA COSTA	60.00	60.00	SSP SWP T	10.82		1
2	WIND FARMS		60.00	60.00	SWP	3.75		1
3	WINDSOR	FITCH MOUNTAIN	60.00	60.00	OTHER SSP	21.06		1
4	WINTU TAP		60.00	60.00	SWP	1.86		1
5	WOHLER TAP		60.00	60.00	SWP	1.44		1
6	WOODBRIDGE TAP		60.00	60.00	SSP SWP	0.53		1
7	YUBA CITY COGEN TAP		60.00	60.00	SWP	0.80		1
8	ZOND WIND TAP		60.00	60.00	SWP	1.19		1
9	HEINZ TAP				SWP	0.79		1
10	A	Y #1 (UNDERGROUND IDLE)			N/A	0.35		1
11	Other					5.01		1
12								
13								
14	Summary of Lines							
15	listed individually above							
16	Towers & Poles		500.00			1,327.67		
17			230.00			5,335.58		
18			115.00			6,180.73		
19			70.00			1,544.52		
20			60.00			3,888.75		
21								
22								
23	Other Undground		230.00			89.96		
24	Transmission Lines		115.00			84.12		
25			70.00			0.39		
26			60.00			7.70		
27								
28	Transmission Roads							
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	36,892.15		1,445

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (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-SINGLE								1
1113-AAC-SINGLE								2
2156-ACSR-BUNDL								3
336.4-AAC-SINGLE								4
1113-AAC-SINGLE								5
477-ACSS-SINGLE								6
397.5-AAC-PARALL								7
1113-AAC-SINGLE								8
4/0-AAC-SINGLE								9
477-ACSS-SINGLE								10
397.5-ACSR-SINGL								11
4/0-AAC-SINGLE								12
715.5-AAC-SINGLE								13
397.5-AAC-SINGLE								14
4/0-AAC-SINGLE								15
3/0-CU-SINGLE 3								16
2300-AAC-BUNDLE								17
2300-AAC-BUNDLE								18
1113-AAC-BUNDLE								19
1113-AAC-BUNDLE								20
336.4-AAC-SINGLE								21
1113-AAC-SINGLE								22
397.5-AAC-SINGLE								23
397.5-AAC-SINGLE								24
1113-AAC-SINGLE								25
1113-AAC-SINGLE								26
397.5-AAC-SINGLE								27
266.8-AAC-PARALL								28
2/0-CU-SINGLE 3								29
1113-AAC-SINGLE								30
1113-AAC-SINGLE								31
3/0-CU-SINGLE 3								32
1113-ACSS-SINGL								33
2300-AAC-BUNDLE								34
795-ACSS-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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) 03/09/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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.
3/0-CU-SINGLE 3								1
715.5-AAC-SINGLE								2
-AAC-SINGLE 266								3
1113-AAC-SINGLE								4
1113-AAC-SINGLE								5
477-ACSS-SINGLE								6
3/0-CU-SINGLE 3								7
1113-AAC-SINGLE								8
2300-AAC-BUNDLE								9
1/0-ACSR-SINGLE								10
1113-AAC-BUNDLE								11
4/0-AAC-SINGLE								12
1/0-ACSR-SINGLE								13
1/0-ACSR-SINGLE								14
397.5-AAC-SINGLE								15
715.5-AAC-SINGLE								16
397.5-AAC-SINGLE								17
715.5-AAC-BUNDL								18
1-CU-SINGLE 3-C								19
250-CU-SINGLE 7								20
1/0-AAC-SINGLE								21
715.5-AAC-SINGLE								22
4/0-AAC-SINGLE								23
715.5-AAC-SINGLE								24
1113-AAC-SINGLE								25
266.8-AAC-SINGLE								26
715.5-AAC-SINGLE								27
397.5-AAC-SINGLE								28
1/0-CU-SINGLE 2								29
2/0-CU-SINGLE 3								30
1/0-CU-SINGLE 7								31
715.5-AAC-SINGLE								32
477-ACSS-SINGLE								33
2/0-CU-SINGLE 3								34
1/0-ACSR-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

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.
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-SINGLE								1
1113-AAC-SINGLE								2
1113-AAC-SINGLE								3
397.5-AAC-SINGLE								4
2-ACSR-SINGLE								5
336.4-AAC-SINGLE								6
1/0-ACSR-SINGLE								7
1/0-CU-SINGLE 2								8
397.5-AAC-SINGLE								9
1113-AAC-SINGLE								10
4/0-AAC-SINGLE								11
1/0-CU-SINGLE 2								12
2500 KCMIL-CU								13
1000 KCMIL-CU								14
715.5-AAC-SINGLE								15
1113-AAC-SINGLE								16
3000 KCMIL-ALUM								17
954-AAC-SINGLE								18
1113-AAC-SINGLE								19
397.5-ACSR-SINGL								20
397.5-AAC-SINGLE								21
4/0-AAC-SINGLE								22
								23
1113-AAC-SINGLE								24
397.5-AAC-SINGLE								25
1113-AAC-BUNDLE								26
1/0-CU-SINGLE 2								27
1113-AAC-BUNDLE								28
1113-AAC-SINGLE								29
477-ACSS-SINGLE								30
250-CU-SINGLE 3								31
518-ACSR-SINGLE								32
477-ACSS-SINGLE								33
1113-AAC-SINGLE								34
1113-ACSS-SINGL								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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.
477-ACSS-SINGLE								1
4/0-AAC-SINGLE								2
2500 KCMIL-CU								3
2000 KCMIL-CU								4
795-ACSR-SINGLE								5
1113-AAC-SINGLE								6
4/0-AAC-SINGLE								7
1/0-ACSR-SINGLE								8
1113-AAC-SINGLE								9
715.5-AAC-SINGLE								10
4/0-AAC-SINGLE								11
1113-AAC-SINGLE								12
715.5-AAC-SINGLE								13
2500 KCMIL-CU								14
2/0-CU-SINGLE 3								15
715.5-AAC-SINGLE								16
4/0-ACSR-SINGLE								17
1113-AAC-SINGLE								18
715.5-AAC-SINGLE								19
4/0-AAC-SINGLE								20
3/0-CU-SINGLE 7								21
397.5-AAC-SINGLE								22
4/0-AAC-SINGLE								23
4/0-AAC-SINGLE								24
715.5-AAC-SINGLE								25
1113-AAC-SINGLE								26
1113-AAC-SINGLE								27
477-ACSS-SINGLE								28
1250 KCMIL-CU								29
397.5-AAC-PARALL								30
1-UNKNOWN-UNK								31
2-ACSR-SINGLE								32
1113-AAC-SINGLE								33
397.5-AAC-SINGLE								34
500-CU-SINGLE 7								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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1113-AAC-SINGLE								1
3000 KCMIL-ALUM								2
715.5-AAC-SINGLE								3
715.5-AAC-SINGLE								4
715.5-AAC-BUNDL								5
2/0-CU-SINGLE 4								6
1113-AAC-SINGLE								7
715.5-AAC-SINGLE								8
4/0-AAC-SINGLE								9
397.5-AAC-SINGLE								10
715.5-AAC-SINGLE								11
								12
1113-AAC-SINGLE								13
1113-AAC-SINGLE								14
4/0-AAC-SINGLE								15
1113-AAC-SINGLE								16
1113-AAC-SINGLE								17
715.5-AAC-SINGLE								18
1113-AAC-BUNDLE								19
397.5-AAC-SINGLE								20
795-ACSS-SINGLE								21
715.5-AAC-BUNDL								22
795-ACSS-SINGLE								23
1/0-ACSR-SINGLE								24
4/0-AAC-SINGLE								25
397.5-AAC-SINGLE								26
								27
1113-AAC-SINGLE								28
2/0-CU-SINGLE 3								29
4/0-ACSR-SINGLE								30
4/0-ACSR-SINGLE								31
4/0-AAC-SINGLE								32
397.5-AAC-SINGLE								33
397.5-AAC-SINGLE								34
477-ACSS-BUNDLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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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1113-AAC-SINGLE								1
1250 KCMIL-CU								2
397.5-AAC-SINGLE								3
4/0-ACSR- 477-A								4
1/0-CU-SINGLE 3								5
1250 KCMIL-								6
								7
1113-AAC-SINGLE								8
397.5-AAC-SINGLE								9
1113-AAC-SINGLE								10
1/0-ACSR-SINGLE								11
1113-AAC-BUNDLE								12
2/0-CU-SINGLE 4								13
4/0-AAC-SINGLE								14
1/0-ACSR-SINGLE								15
715.5-AAC-SINGLE								16
250-CU-SINGLE 3								17
397.5-AAC-SINGLE								18
715.5-AAC-SINGLE								19
477-ACSS-SINGLE								20
477-ACSS-SINGLE								21
397.5-AAC-SINGLE								22
477-ACSS-SINGLE								23
1113-AAC-SINGLE								24
477-ACSS-SINGLE								25
1/0-CU-SINGLE								26
477-ACSS-SINGLE								27
4/0-AAC-SINGLE								28
397.5-ACSR-SINGL								29
397.5-AAC-SINGLE								30
1113-AAC-SINGLE								31
715.5-AAC-SINGLE								32
250-CU-SINGLE 3								33
2/0-CU-SINGLE 2								34
4/0-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954-ACSR-SINGLE								1
266.8-AAC-SINGLE								2
397.5-AAC-SINGLE								3
4/0-AAC-SINGLE								4
2/0-CU-SINGLE 4								5
1/0-CU-SINGLE 3								6
397.5-AAC-SINGLE								7
715.5-AAC-SINGLE								8
477-ACSS-SINGLE								9
397.5-AAC-SINGLE								10
266.8-AAC-SINGLE								11
397.5-AAC-SINGLE								12
1113-AAC-SINGLE								13
-								14
715.5-AAC-BUNDL								15
1113-AAC-BUNDLE								16
477-ACSS-SINGLE								17
1113-AAC-BUNDLE								18
4/0-AAC-SINGLE								19
1113-AAC-SINGLE								20
1113-AAC-SINGLE								21
3/0-AAC-SINGLE								22
1/0-CU-SINGLE 3								23
397.5-AAC-SINGLE								24
1113-AAC-SINGLE								25
								26
3/0-CU-SINGLE 3								27
397.5-AAC-SINGLE								28
397.5-AAC-SINGLE								29
266.8-AAC-SINGLE								30
477-ACSS-SINGLE								31
1852-ACSR-BUNDL								32
715.5-AAC-SINGLE								33
715.5-AAC-SINGLE								34
1113-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
397.5-AAC-SINGLE								2
2-UNKNOWN-SING								3
715.5-AAC-BUNDL								4
715.5-AAC-BUNDL								5
477-ACSS-SINGLE								6
1/0-AAC- 4/0-AA								7
2/0-CU-SINGLE 4								8
477-ACSS-SINGLE								9
477-ACSS-SINGLE								10
397.5-AAC-SINGLE								11
715.5-AAC-SINGLE								12
1-UNKNOWN-UNK								13
715.5-AAC-SINGLE								14
1113-AAC-BUNDLE								15
1113-AAC-BUNDLE								16
1113-AAC-BUNDLE								17
2/0-CU-SINGLE								18
1113-AAC-SINGLE								19
715.5-AAC-SINGLE								20
1750 KCMIL-ALUM								21
2/0-CU-SINGLE								22
4/0-ACSR-SINGLE								23
795-ACSR-SINGLE								24
715.5-AAC-SINGLE								25
1113-AAC-SINGLE								26
715.5-AAC-SINGLE								27
2300-AAC-BUNDLE								28
1113-AAC-SINGLE								29
250-CU-PARALLEL								30
715.5-AAC-SINGLE								31
397.5-AAC-SINGLE								32
1250 KCMIL-								33
								34
3000 KCMIL-								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (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.
2000 KCMIL-ALUM								1
1250 KCMIL-CU								2
3000 KCMIL-CU								3
336.4-ACSR-SINGL								4
1272-ACSR-BUNDL								5
4/0-AAC-SINGLE								6
2/0-CU-SINGLE 7								7
1/0-ACSR-SINGLE								8
4/0-AAC-SINGLE								9
1/0-CU-SINGLE 2								10
1113-AAC-SINGLE								11
336.4-AAC-SINGLE								12
336.4-AAC-SINGLE								13
2500 KCMIL-CU								14
397.5-AAC-SINGLE								15
1431-AAC-SINGLE								16
1113-AAC-SINGLE								17
397.5-ALUM-SINGL								18
4/0-AAC-SINGLE								19
2/0-CU-SINGLE								20
2/0-CU-SINGLE 3								21
715.5-AAC-SINGLE								22
1/0-ACSR-SINGLE								23
4/0-AAC-SINGLE								24
397.5-AAC-SINGLE								25
2/0-CU-SINGLE 2								26
4/0-AAC-SINGLE								27
954-ACSS-SINGLE								28
397.5-AAC-SINGLE								29
1113-AAC-BUNDLE								30
2300-AAC-BUNDLE								31
397.5-AAC-SINGLE								32
2-ACSR-SINGLE								33
397.5-AAC-SINGLE								34
477-ACSS-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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-SINGLE								1
2/0-CU-SINGLE 4								2
3/0-AAC-SINGLE								3
1113-AAC-SINGLE								4
397.5-AAC-SINGLE								5
3/0-AAC-SINGLE								6
397.5-AAC-SINGLE								7
397.5-AAC-SINGLE								8
3/0-AAC-SINGLE								9
715.5-AAC-SINGLE								10
4/0-AAC-SINGLE								11
4/0-AAC-SINGLE								12
397.5-AAC-SINGLE								13
477-ACSS-SINGLE								14
1113-AAC-SINGLE								15
4/0-AAC-SINGLE								16
3500 KCMIL-ALUM								17
3500 KCMIL-ALUM								18
1113-AAC-SINGLE								19
4/0-AAC-SINGLE								20
4/0-CU-SINGLE								21
2/0-CU-SINGLE 3								22
715.5-AAC-SINGLE								23
397.5-AAC-SINGLE								24
397.5-AAC-SINGLE								25
2/0-CU-SINGLE 4								26
397.5-AAC-SINGLE								27
1/0-ACSR-SINGLE								28
397.5-AAC-SINGLE								29
4/0-AAC-SINGLE								30
397.5-AAC-SINGLE								31
4/0-AAC-SINGLE								32
715.5-AAC-SINGLE								33
350-AAC-SINGLE								34
397.5-ACSR-SINGL								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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.
2/0-CU-SINGLE								1
2/0-CU-SINGLE								2
643.7--SINGLE 9								3
715.5-AAC-SINGLE								4
4/0-AAC-SINGLE								5
477-ACSS-SINGLE								6
1431-AAC-BUNDLE								7
397.5-AAC-SINGLE								8
4/0-CU-SINGLE 4								9
266.8-AAC-PARALL								10
1113-AAC-SINGLE								11
1113-AAC-SINGLE								12
397.5-AAC-SINGLE								13
1113-AAC-SINGLE								14
477-ACSS-SINGLE								15
336.4-AAC-SINGLE								16
715.5-AAC-SINGLE								17
795-ACSR-SINGLE								18
477-ACSS-SINGLE								19
477-ACSS-SINGLE								20
397.5-AAC-SINGLE								21
795-ACSS-SINGLE								22
								23
2/0-CU-SINGLE 7								24
								25
397.5-AAC-SINGLE								26
643.7--SINGLE 9								27
350-AAC-SINGLE								28
1113-AAC-SINGLE								29
397.5-AAC-SINGLE								30
4/0-AAC-SINGLE								31
1113-AAC-SINGLE								32
1431-AAC-BUNDLE								33
3/0-CU-PARALLEL								34
397.5-ACSR-SINGL								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/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.
4/0-AAC-SINGLE								1
4/0-AAC-SINGLE								2
350-AAC-SINGLE								3
1431-AAC-SINGLE								4
795-ACSR-SINGLE								5
4/0-AAC-SINGLE								6
1113-AAC-SINGLE								7
1/0-ACSR-SINGLE								8
2300-AAC-BUNDLE								9
4/0-AAC-SINGLE								10
1113-AAC-SINGLE								11
4/0-AAC-SINGLE								12
4/0-AAC-SINGLE								13
3/0-CU-SINGLE 4								14
1113-AAC-SINGLE								15
1250 KCMIL-CU								16
715.5-AAC-SINGLE								17
1113-AAC-BUNDLE								18
715.5-AAC-SINGLE								19
4/0-AAC-SINGLE								20
715.5-AAC-SINGLE								21
3500 KCMIL-CU								22
715.5-AAC-SINGLE								23
4/0-AAC-SINGLE								24
1113-AAC-SINGLE								25
1113-AAC-SINGLE								26
4/0-ACSR-SINGLE								27
4/0-ACSR-SINGLE								28
1113-AAC-SINGLE								29
397.5-AAC-SINGLE								30
1/0-CU-SINGLE 3								31
4/0-ACSR-SINGLE								32
3/0-CU-SINGLE								33
4/0-CU-PARALLEL								34
2/0-CU-SINGLE 3								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

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)	
1-CU-BUNDLE 4-C								1
336.4-ACSR-SINGL								2
336.4-ACSR-SINGL								3
3/0-CU-SINGLE								4
4/0-AAC-SINGLE								5
397.5-AAC-SINGLE								6
397.5-AAC-SINGLE								7
1113-AAC-SINGLE								8
1113-AAC-SINGLE								9
4/0-AAC-SINGLE								10
397.5-AAC-SINGLE								11
477-ACSS-SINGLE								12
715.5-AAC-SINGLE								13
1113-AAC-SINGLE								14
3/0-CU-SINGLE 3								15
336.4-AAC-SINGLE								16
715.5-AAC-SINGLE								17
3/0-AAC-SINGLE								18
1113-AAC-SINGLE								19
1/0-ACSR-SINGLE								20
3/0-CU-SINGLE 3								21
2/0-CU-SINGLE 3								22
1113-AAC-SINGLE								23
795-ACSS-SINGLE								24
1113-AAC-SINGLE								25
795-ACSR-SINGLE								26
4/0-AAC-SINGLE								27
954-AAC-SINGLE								28
795-ACSR-SINGLE								29
397.5-AAC-SINGLE								30
1/0-CU-SINGLE 3								31
4/0-AAC-BUNDLE								32
715.5-AAC-SINGLE								33
397.5-AAC-SINGLE								34
-AAC-SINGLE 111								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2/0-CU-SINGLE 4								1
1113-AAC-SINGLE								2
715.5-AAC-BUNDL								3
336.4-AAC-SINGLE								4
3/0-CU-SINGLE								5
								6
3500 KCMIL-CU								7
3000 KCMIL-								8
3000 KCMIL-ALUM								9
715.5-AAC-SINGLE								10
1113-AAC-SINGLE								11
4/0-AAC-SINGLE								12
266.8-AAC-SINGLE								13
715.5-AAC-SINGLE								14
4/0-AAC-SINGLE								15
1431-AAC-SINGLE								16
1113-ACSS-SINGL								17
1113-AAC-SINGLE								18
250-CU-SINGLE 3								19
2-ACSR-SINGLE								20
1113-AAC-SINGLE								21
397.5-AAC-SINGLE								22
4/0-AAC-SINGLE								23
477-ACSS-SINGLE								24
266.8-AAC-SINGLE								25
397.5-AAC-SINGLE								26
795-ACSR-SINGLE								27
1/0-CU-SINGLE 3								28
397.5-AAC-SINGLE								29
477-ACSS-SINGLE								30
1-CU-SINGLE 1/0								31
2-CU-SINGLE 397								32
397.5-AAC-SINGLE								33
3/0-CU-PARALLEL								34
								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1250 KCMIL-CU								1
715.5-AAC-SINGLE								2
1113-AAC-BUNDLE								3
954-ACSS-SINGLE								4
1/0-CU-SINGLE 3								5
250-CU-SINGLE 3								6
715.5-AAC-SINGLE								7
4/0-AAC-SINGLE								8
250-CU-SINGLE 3								9
397.5-AAC-SINGLE								10
397.5-AAC-SINGLE								11
4/0-ACSR-SINGLE								12
336.4-AAC-SINGLE								13
336.4-AAC-SINGLE								14
250-CU-SINGLE 3								15
3/0-CU-SINGLE 3								16
2-ACSR-SINGLE								17
954-ACSR-PARALL								18
4/0-AAC-SINGLE								19
2/0-CU-SINGLE 1								20
3000 KCMIL-CU								21
2-ACSR-SINGLE								22
397.5-AAC-SINGLE								23
1113-AAC-SINGLE								24
715.5-AAC-SINGLE								25
1113-AAC-BUNDLE								26
397.5-AAC-SINGLE								27
								28
1113-AAC-SINGLE								29
1250 KCMIL-CU								30
266.8-ACSR-SINGL								31
1431-AAC-BUNDLE								32
3/0-CU-SINGLE 7								33
397.5-AAC-SINGLE								34
1/0-CU-SINGLE 2								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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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2300-AAC-BUNDLE								1
1113-AAC-SINGLE								2
4/0-AAC-SINGLE								3
1272-ACSR-BUNDL								4
397.5-AAC-SINGLE								5
397.5-AAC-SINGLE								6
477-ACSS-SINGLE								7
1113-AAC-SINGLE								8
954-ACSS-SINGLE								9
715.5-AAC-SINGLE								10
397.5-AAC-SINGLE								11
1-CU-SINGLE 1/0								12
715.5-AAC-SINGLE								13
1113-AAC-BUNDLE								14
2-ACSR-SINGLE 2								15
1113-AAC-BUNDLE								16
1/0-CU-SINGLE 2								17
397.5-ACSR-SINGL								18
3/0-CU-SINGLE 3								19
715.5-AAC-SINGLE								20
397.5-AAC-SINGLE								21
397.5-AAC-SINGLE								22
4/0-AAC-SINGLE								23
397.5-AAC-SINGLE								24
2-CU-SINGLE								25
4/0-ACSR-SINGLE								26
2/0-CU-SINGLE 3								27
2300-AAC-BUNDLE								28
2-ACSR-SINGLE								29
1/0-CU-SINGLE 1								30
4/0-AAC-SINGLE								31
250-CU-PARALLEL								32
397.5-AAC-SINGLE								33
3/0-CU-SINGLE 3								34
1113-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
4/0-AAC-SINGLE								1
1113-ACSS-SINGL								2
954-ACSS-SINGLE								3
2500 KCMIL-CU								4
2500 KCMIL-CU								5
954-ACSS-SINGLE								6
3/0-CU-SINGLE								7
4/0-CU-SINGLE 7								8
4/0-CU-PARALLEL								9
1/0-CU-SINGLE 4								10
1113-AAC-PARALL								11
477-ACSS-SINGLE								12
1/0-ACSR-SINGLE								13
2-CU-SINGLE 2/0								14
1/0-CU-SINGLE 2								15
1113-AAC-SINGLE								16
2/0-CU-SINGLE 3								17
2/0-CU-SINGLE 3								18
1113-AAC-SINGLE								19
397.5-AAC-SINGLE								20
1113-AAC-SINGLE								21
715.5-AAC-SINGLE								22
2300-AAC-BUNDLE								23
250-CU-SINGLE 5								24
2/0-CU-SINGLE 4								25
2/0-CU-SINGLE 3								26
1/0-ACSR-SINGLE								27
715.5-AAC-SINGLE								28
795-ACSR-SINGLE								29
715.5--SINGLE								30
1/0-ACSR-SINGLE								31
397.5-AAC-SINGLE								32
4/0-AAC-SINGLE								33
4/0-AAC-SINGLE								34
397.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
477-ACSS-SINGLE								1
4/0-AAC-SINGLE								2
3/0-CU-SINGLE 3								3
2/0-CU-SINGLE 4								4
2/0-CU-SINGLE 7								5
954-ACSR-SINGLE								6
2/0-CU-SINGLE 5								7
397.5-AAC-SINGLE								8
1113-AAC-SINGLE								9
1113-AAC-SINGLE								10
2300-AAC-BUNDLE								11
715.5-AAC-SINGLE								12
715.5-AAC-SINGLE								13
1113-AAC-SINGLE								14
795-ACSR-SINGLE								15
2/0-CU-SINGLE 3								16
397.5-AAC-SINGLE								17
3/0-CU-SINGLE 3								18
1113-AAC-SINGLE								19
3000 KCMIL-CU								20
2/0-CU-SINGLE								21
397.5-ACSR-SINGL								22
4-CU-SINGLE								23
2-CU-SINGLE 4/0								24
715.5-AAC-SINGLE								25
715.5-AAC-SINGLE								26
266.8-AAC-SINGLE								27
715.5-AAC-SINGLE								28
397.5-AAC-SINGLE								29
477-ACSS-SINGLE								30
2/0-CU-SINGLE 7								31
2/0-CU-SINGLE 7								32
3/0-CU-SINGLE 7								33
266.8-AAC-SINGLE								34
266.8-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

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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.
397.5-ACSR-SINGL								1
250-CU-SINGLE								2
2-CU-SINGLE 2/0								3
3/0-CU-PARALLEL								4
266.8-AAC-SINGLE								5
336.4-AAC-SINGLE								6
397.5-ACSR-SINGL								7
397.5-AAC-SINGLE								8
954-ACSS-SINGLE								9
2300-AAC-BUNDLE								10
715.5-AAC-SINGLE								11
397.5-AAC-SINGLE								12
397.5-AAC-SINGLE								13
715.5-AAC-SINGLE								14
								15
715.5-AAC-SINGLE								16
715.5-AAC-SINGLE								17
4/0-AAC-SINGLE								18
1113-AAC-SINGLE								19
1113-AAC-SINGLE								20
715.5-AAC-SINGLE								21
715.5-AAC-PARALL								22
397.5-AAC-SINGLE								23
500-CU-SINGLE 5								24
2-ACSR-SINGLE 2								25
1/0-CU-SINGLE 3								26
1/0-ACSR-SINGLE								27
2/0-CU-SINGLE 3								28
336.4-AAC-SINGLE								29
2500 KCMIL-CU								30
1113-AAC-SINGLE								31
336.4-AAC-SINGLE								32
4/0-AAC-SINGLE								33
4-CU-SINGLE								34
954-ACSS-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1113-AAC-BUNDLE								1
								2
715.5-AAC- 397.								3
715.5-AAC- 397.								4
643.7--SINGLE 9								5
1/0-AAC-SINGLE								6
397.5-AAC-SINGLE								7
								8
266.8-AAC-SINGLE								9
4-CU-SINGLE								10
4/0-AAC-SINGLE								11
307.1-AAC-SINGLE								12
266.8-AAC-SINGLE								13
4/0-AAC-SINGLE								14
								15
336.4-AAC-SINGLE								16
500 KCMIL-								17
1250 KCMIL-ALUM								18
397.5-AAC-SINGLE								19
								20
397.5-AAC-SINGLE								21
397.5-ACSR-SINGL								22
4/0-AAC-SINGLE								23
477-ACSS-SINGLE								24
250-CU-SINGLE 2								25
4/0-ACSR-SINGLE								26
4/0-AAC-SINGLE								27
4/0-AAC-SINGLE								28
1113-AAC-SINGLE								29
2-ACSR-SINGLE 2								30
2/0-CU-SINGLE								31
4/0-AAC-SINGLE								32
250-CU-SINGLE 3								33
4/0-ACSR-SINGLE								34
4/0-CU-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	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 4								1
2-CU-PARALLEL 3								2
4/0-AAC-SINGLE								3
1113-AAC-SINGLE								4
266.8-AAC-SINGLE								5
266.8-AAC-SINGLE								6
4/0-CU-SINGLE 4								7
								8
3000 KCMIL-CU								9
								10
4/0-AAC-SINGLE								11
715.5-AAC-SINGLE								12
1113-AAC-BUNDLE								13
1113-AAC-SINGLE								14
2300-AAC-BUNDLE								15
2/0-CU-SINGLE								16
643.7--SINGLE 9								17
397.5-AAC-SINGLE								18
1-CU-SINGLE 2-C								19
1/0-ACSR-SINGLE								20
4/0-AAC-SINGLE								21
1113-AAC-SINGLE								22
1113-ACSS-SINGL								23
397.5-AAC-SINGLE								24
336.4-AAC-SINGLE								25
795-ACSR-SINGLE								26
2300-AAC-BUNDLE								27
1113-ACSS-SINGL								28
397.5-ACSR-SINGL								29
397.5-AAC-SINGLE								30
397.5-AAC-SINGLE								31
2/0-CU-SINGLE 4								32
1113-AAC-SINGLE								33
1-UNKNOWN-UNK								34
2/0-CU-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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1113-ACSS-SINGL								1
795-ACSR-SINGLE								2
795-ACSR-SINGLE								3
1-CU-SINGLE 4/0								4
2/0-CU-SINGLE 7								5
4/0-AAC-SINGLE								6
3/0-CU-SINGLE 7								7
1113-AAC-SINGLE								8
1/0-ACSR-SINGLE								9
4/0-AAC-SINGLE								10
477-ACSS-SINGLE								11
1113-AAC-SINGLE								12
4/0-AAC-SINGLE								13
1431-AAC-SINGLE								14
397.5-ACSR-SINGL								15
795-ACSS-SINGLE								16
715.5-AAC-SINGLE								17
715.5-AAC-SINGLE								18
715.5-AAC-SINGLE								19
1113-AAC-BUNDLE								20
1113-AAC-SINGLE								21
715.5-AAC-SINGLE								22
715.5-AAC-BUNDL								23
1/0-CU-SINGLE 4								24
								25
								26
1750 KCMIL-ALUM								27
1113-AAC-BUNDLE								28
715.5-AAC-SINGLE								29
3/0-CU-SINGLE								30
1-UNKNOWN-UNK								31
2/0-CU-SINGLE 3								32
1431-AAC-BUNDLE								33
								34
2/0-CU-SINGLE 7								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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) 03/09/2018	Year/Period of Report End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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2/0-CU-SINGLE 4								1
2/0-CU-SINGLE 3								2
397.5-ACSR-SINGL								3
397.5-AAC-SINGLE								4
266.8-AAC-SINGLE								5
715.5-AAC-SINGLE								6
1113-AAC-SINGLE								7
1-CU-SINGLE 1/0								8
2/0-CU-SINGLE 3								9
397.5-AAC-SINGLE								10
1113-AAC-SINGLE								11
2/0-AAC-SINGLE								12
3/0-CU-PARALLEL								13
1/0-ACSR-SINGLE								14
397.5-AAC-SINGLE								15
477-ACSS-SINGLE								16
1113-AAC-SINGLE								17
397.5-AAC-SINGLE								18
250-CU-SINGLE 7								19
795-ACSR-SINGLE								20
1113-AAC-SINGLE								21
4/0-AAC-SINGLE								22
3/0-CU-SINGLE 3								23
4/0-AAC-SINGLE								24
397.5-AAC-SINGLE								25
2/0-CU-SINGLE								26
2/0-CU-SINGLE								27
4/0-AAC-SINGLE								28
3/0-CU-SINGLE 7								29
1/0-ACSR-SINGLE								30
3/0-CU-SINGLE 7								31
715.5-AAC-SINGLE								32
397.5-AAC-SINGLE								33
715.5-AAC-SINGLE								34
1113-AAC-BUNDLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	
								1
1000 KCMIL-CU								2
								3
4/0-AAC-SINGLE								4
1/0-ACSR-SINGLE								5
4/0-AAC-SINGLE								6
1113-AAC-SINGLE								7
397.5-AAC-SINGLE								8
477-ACSS-SINGLE								9
1113-AAC-SINGLE								10
4/0-AAC-SINGLE								11
-								12
795-ACSR-SINGLE								13
4/0-ACSR-SINGLE								14
397.5-AAC-SINGLE								15
4/0-AAC-SINGLE								16
500-CU-SINGLE 7								17
2-ACSR-SINGLE 2								18
1/0-ACSR-SINGLE								19
1113-AAC-SINGLE								20
266.8-AAC-SINGLE								21
1/0-ACSR-SINGLE								22
4/0-CU-SINGLE 4								23
1/0-ACSR-SINGLE								24
2-CU-SINGLE								25
4/0-AAC-SINGLE								26
1113-ACSS-SINGL								27
715.5-AAC-SINGLE								28
1113-AAC-SINGLE								29
1113-AAC-SINGLE								30
477-ACSS-SINGLE								31
2300-AAC- 477-A								32
1431-AAC-SINGLE								33
2000 KCMIL-CU								34
2300-AAC-BUNDLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
477-ACSS-SINGLE								1
715.5-AAC-SINGLE								2
2/0-CU-SINGLE 3								3
795-ACSS-SINGLE								4
397.5-AAC-SINGLE								5
715.5-AAC-SINGLE								6
4/0-AAC-SINGLE								7
954-ACSS-SINGLE								8
4/0-AAC-SINGLE								9
4/0-AAC-SINGLE								10
4/0-AAC-SINGLE								11
715.5-AAC-SINGLE								12
4/0-AAC-SINGLE								13
2/0-CU-SINGLE								14
397.5-AAC-SINGLE								15
397.5-AAC-SINGLE								16
2-ACSR-SINGLE 2								17
397.5-ACSR-PARA								18
954-AAC-SINGLE								19
336.4-ACSR-SINGL								20
397.5-ACSR-SINGL								21
2/0-CU-SINGLE 3								22
2/0-CU-SINGLE 3								23
4/0-AAC-SINGLE								24
715.5-AAC-SINGLE								25
397.5-ACSR-SINGL								26
266.8-AAC-SINGLE								27
								28
397.5-AAC-SINGLE								29
954-AAC-SINGLE								30
397.5-AAC-SINGLE								31
1/0-CU-SINGLE 3								32
1/0-CU-SINGLE 4								33
1/0-CU-SINGLE 4								34
397.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

TRANSMISSION LINE STATISTICS (Continued)

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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)	
1-UNKNOWN-UNK								1
1/0-CU-SINGLE 2								2
2/0-CU-SINGLE 3								3
2/0-CU-SINGLE 2								4
2/0-CU-SINGLE 3								5
1250 KCMIL-ALUM								6
1113-AAC-SINGLE								7
2/0-CU-SINGLE 4								8
1/0-ACSR-SINGLE								9
397.5-AAC-SINGLE								10
266.8-AAC-SINGLE								11
250-CU-SINGLE 3								12
4/0-AAC-SINGLE								13
397.5-AAC-SINGLE								14
477-ACSS-SINGLE								15
4/0-AAC-SINGLE								16
795-ACSS-SINGLE								17
1/0-ACSR-SINGLE								18
1855-ACSR-BUNDL								19
2300-AAC-BUNDLE								20
1113-AAC-SINGLE								21
2300-AAC-BUNDLE								22
4/0-AAC-SINGLE								23
2-ACSR-SINGLE 2								24
715.5-AAC-SINGLE								25
2/0-CU-SINGLE 4								26
336.4-AAC-SINGLE								27
715.5-AAC-SINGLE								28
2-ACSR-SINGLE								29
4-CU-SINGLE 4/0								30
1113-AAC-SINGLE								31
2000 KCMIL-CU								32
2300-AAC-BUNDLE								33
954-ACSS-SINGLE								34
397.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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)	
397.5-ALUM- 3/0								1
1113-AAC-BUNDLE								2
1/0-ACSR-SINGLE								3
1113-AAC-BUNDLE								4
1113-AAC-SINGLE								5
1/0-ACSR-SINGLE								6
3/0-CU-SINGLE 3								7
397.5-AAC-SINGLE								8
397.5-AAC-SINGLE								9
1/0-ACSR-SINGLE								10
795-ACSS-SINGLE								11
1113-AAC-SINGLE								12
336.4-AAC-SINGLE								13
2300-AAC-BUNDLE								14
1113-AAC-SINGLE								15
2300-AAC-BUNDLE								16
3/0-CU-BUNDLE 1								17
1113-AAC-BUNDLE								18
4/0-AAC-SINGLE								19
2/0-ACSR-SINGLE								20
4/0-AAC-SINGLE								21
1113-AAC-SINGLE								22
1113-AAC-SINGLE								23
1113-AAC-SINGLE								24
477-ACSS-SINGLE								25
1113-AAC-BUNDLE								26
3/0-CU-SINGLE 3								27
1113-AAC-SINGLE								28
1-CU-SINGLE								29
266.8-AAC-SINGLE								30
3/0-CU-PARALLEL								31
2300-AAC-BUNDLE								32
4/0-AAC-SINGLE								33
1113-ACSS-SINGL								34
2300-AAC-BUNDLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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-SINGLE								1
1-CU-SINGLE 111								2
954-ACSS-SINGLE								3
4/0-AAC-SINGLE								4
4/0-AAC-SINGLE								5
397.5-AAC-SINGLE								6
397.5-AAC-SINGLE								7
715.5-AAC-SINGLE								8
397.5-AAC-SINGLE								9
1/0-CU-SINGLE 2								10
2300-AAC-BUNDLE								11
1113-ACSS-SINGL								12
1113-ACSS-SINGL								13
1113-ACSS-SINGL								14
715.5-AAC-SINGLE								15
477-ACSS-SINGLE								16
1-CU-SINGLE								17
397.5-AAC-SINGLE								18
477-ACSS-SINGLE								19
1113-AAC-SINGLE								20
397.5-AAC-SINGLE								21
397.5-AAC-SINGLE								22
715.5-AAC-SINGLE								23
397.5-AAC-SINGLE								24
715.5-AAC-SINGLE								25
4/0-AAC-SINGLE								26
2-ACSR-SINGLE								27
1113-AAC-BUNDLE								28
477-ACSS-SINGLE								29
715.5-AAC-SINGLE								30
4/0-AAC-SINGLE								31
715.5-AAC-SINGLE								32
4/0-AAC-SINGLE								33
954-ACSS-SINGLE								34
4/0-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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-SINGLE								1
1113-AAC-SINGLE								2
477-ACSS-SINGLE								3
336.4-ACAR-SINGL								4
4/0-AAC-SINGLE								5
1113-AAC-SINGLE								6
1113-ACSS-SINGL								7
1855-ACSR-BUNDL								8
2/0-CU-SINGLE 3								9
250-CU-SINGLE 3								10
397.5-AAC-SINGLE								11
1113-AAC-SINGLE								12
2-ACSR-SINGLE								13
3/0-AAC-SINGLE								14
1113-AAC-SINGLE								15
1113-AAC-SINGLE								16
397.5-AAC-SINGLE								17
4/0-AAC-SINGLE								18
954-ACSS-SINGLE								19
1/0-CU-SINGLE 2								20
1113-AAC-SINGLE								21
1113-AAC-SINGLE								22
1113-AAC-SINGLE								23
1113-AAC-SINGLE								24
2/0-CU-SINGLE 4								25
715.5-AAC-SINGLE								26
2300-AAC-BUNDLE								27
397.5-AAC-SINGLE								28
4/0-AAC-SINGLE								29
4/0-AAC-SINGLE								30
2-ACSR-SINGLE								31
4/0-AAC-SINGLE								32
397.5-ALUM- 4/0								33
397.5-ACSR-SINGL								34
4/0-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2/0-CU-SINGLE 3								1
336.4-AAC-SINGLE								2
4/0-AAC-SINGLE								3
2/0-CU-SINGLE 3								4
1/0-CU-SINGLE 7								5
2-ACSR-SINGLE 4								6
397.5-AAC-SINGLE								7
1/0-ACSR-SINGLE								8
1113-AAC-SINGLE								9
477-ACSS-SINGLE								10
266.8-ACAR-SINGL								11
715.5-AAC-SINGLE								12
477-ACSS-SINGLE								13
477-ACSS-SINGLE								14
250-CU-SINGLE 3								15
4/0-AAC-SINGLE								16
266.8-AAC-SINGLE								17
715.5-AAC-SINGLE								18
397.5-ACSR-SINGL								19
2-CU-SINGLE 4/0								20
1113-AAC-SINGLE								21
4/0-AAC-SINGLE								22
715.5-AAC-SINGLE								23
1113-AAC-SINGLE								24
1-CU-SINGLE 1/0								25
397.5-AAC-SINGLE								26
715.5-AAC-SINGLE								27
4/0-CU-PARALLEL								28
715.5-AAC-SINGLE								29
715.5-AAC-SINGLE								30
1113-AAC-SINGLE								31
397.5-AAC-SINGLE								32
266.8-AAC-SINGLE								33
266.8-AAC-SINGLE								34
715.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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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1113-AAC-SINGLE								1
250-CU-SINGLE 7								2
1113-AAC-SINGLE								3
4/0-AAC-SINGLE								4
336.4-AAC-SINGLE								5
3/0-CU-BUNDLE 7								6
1113-AAC-SINGLE								7
1113-AAC-SINGLE								8
397.5-AAC-SINGLE								9
4/0-AAC-SINGLE								10
3/0-CU-PARALLEL								11
715.5-AAC-SINGLE								12
477-ACSS-SINGLE								13
477-ACSS-SINGLE								14
954-ACSR-SINGLE								15
4/0-CU-PARALLEL								16
795-ACSR-SINGLE								17
250-CU-SINGLE								18
250-CU-SINGLE 3								19
3/0-CU-PARALLEL								20
795-ACSR-SINGLE								21
3/0-CU-SINGLE 7								22
518-ACSR-SINGLE								23
3/0-CU-SINGLE 7								24
397.5-ACSR-SINGL								25
4/0-CU-SINGLE 7								26
397.5-ACSR-SINGL								27
715.5-AAC-SINGLE								28
3/0-CU-PARALLEL								29
								30
715.5-AAC-SINGLE								31
266.8-AAC-SINGLE								32
1113-AAC-SINGLE								33
715.5-AAC-SINGLE								34
1113-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

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TRANSMISSION LINE STATISTICS (Continued)

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1113-AAC-SINGLE								1
1113-AAC-SINGLE								2
2300-AAC-SINGLE								3
500--SINGLE								4
1113-AAC-SINGLE								5
397.5-AAC-SINGLE								6
715.5-AAC-BUNDL								7
397.5-AAC-SINGLE								8
1/0-CU-SINGLE 3								9
477-ACSS-SINGLE								10
250-CU-PARALLEL								11
477-ACSS-SINGLE								12
795-ACSS-SINGLE								13
1113-AAC-SINGLE								14
477-ACSS-SINGLE								15
2/0-CU-SINGLE 4								16
397.5-AAC-SINGLE								17
715.5-AAC-SINGLE								18
4/0-AAC-SINGLE								19
1113-ACSS-SINGL								20
1113-ACSS-SINGL								21
397.5-AAC-SINGLE								22
2/0-CU-SINGLE 7								23
715.5-AAC-SINGLE								24
2-CU-SINGLE								25
1/0-ACSR-SINGLE								26
1113-AAC-BUNDLE								27
250-CU-SINGLE 7								28
4/0-AAC-SINGLE								29
397.5-AAC-SINGLE								30
1113-AAC-SINGLE								31
477-ACSS-SINGLE								32
477-ACSS-SINGLE								33
477-ACSS-SINGLE								34
2/0-CU-SINGLE 3								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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.
500--SINGLE 715								1
397.5-AAC-SINGLE								2
477-ACSS-SINGLE								3
2500 KCMIL-CU								4
2/0-CU-SINGLE 3								5
1/0-CU-SINGLE 2								6
2/0-CU-SINGLE 3								7
3/0-CU-SINGLE 3								8
397.5-AAC-SINGLE								9
715.5-AAC-SINGLE								10
954-ACSS-BUNDLE								11
715.5-AAC- 2/0-								12
397.5-AAC-SINGLE								13
1/0-CU-SINGLE 2								14
4/0-AAC-SINGLE								15
715.5-AAC-SINGLE								16
397.5-AAC-SINGLE								17
477-ACSS-SINGLE								18
715.5-AAC-SINGLE								19
4/0-CU-SINGLE 7								20
2300-AAC-SINGLE								21
477-ACSS-SINGLE								22
954-ACSS-SINGLE								23
1113-AAC-SINGLE								24
4/0-AAC-SINGLE								25
3500 KCMIL-CU								26
795-ACSR-SINGLE								27
1-UNKNOWN-UNK								28
266.8-AAC-SINGLE								29
3/0-CU-SINGLE 3								30
4/0-AAC-SINGLE								31
477-ACSS-SINGLE								32
2/0-CU-SINGLE 3								33
2/0-CU-SINGLE 7								34
4/0-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/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.
715.5-AAC-SINGLE								1
715.5-AAC-SINGLE								2
250-CU-SINGLE 3								3
2/0-CU-SINGLE 3								4
397.5-AAC-SINGLE								5
477-ACSS-SINGLE								6
266.8-AAC-SINGLE								7
2/0-CU-SINGLE								8
1-UNKNOWN-UNK								9
250-CU-SINGLE 3								10
1/0-CU-SINGLE 3								11
4/0-AAC-SINGLE								12
4/0-ACSR-SINGLE								13
715.5-AAC-SINGLE								14
2/0-CU-SINGLE 3								15
1113-AAC-SINGLE								16
1113-AAC-SINGLE								17
715.5-AAC- 397.								18
397.5-AAC-SINGLE								19
4-CU-SINGLE								20
715.5-AAC-SINGLE								21
1/0-ACSR-SINGLE								22
3/0-CU-SINGLE								23
336.4-ACSR-SINGL								24
715.5-AAC-SINGLE								25
3/0-CU-SINGLE								26
715.5-AAC-SINGLE								27
3/0-CU-SINGLE 3								28
715.5-AAC-BUNDL								29
1113-ACSS-SINGL								30
1113-ACSS-SINGL								31
2/0-CU-SINGLE								32
2/0-CU-SINGLE 3								33
4/0-AAC-SINGLE								34
2/0-CU-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/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.
1/0-ACSR-SINGLE								1
397.5-AAC-SINGLE								2
266.8-AAC-SINGLE								3
1113-AAC-SINGLE								4
4/0-AAC-SINGLE								5
266.8-AAC-SINGLE								6
1/0-CU-SINGLE								7
2/0-CU-SINGLE 4								8
1113-AAC-SINGLE								9
4/0-AAC-SINGLE								10
397.5-AAC-SINGLE								11
715.5-AAC-SINGLE								12
2/0-CU-SINGLE 7								13
4/0-AAC-SINGLE								14
397.5-AAC-SINGLE								15
477-ACSS-SINGLE								16
1113-AAC-BUNDLE								17
1113-AAC-SINGLE								18
500-CU-SINGLE 5								19
3/0-CU-SINGLE 3								20
1113-AAC-SINGLE								21
715.5-AAC- 397.								22
1113-AAC-BUNDLE								23
795-ACSR-SINGLE								24
4/0-CU-SINGLE								25
2300-AAC-BUNDLE								26
477-ACSS-SINGLE								27
2300-AAC-BUNDLE								28
3/0-CU-SINGLE								29
715.5-AAC-BUNDL								30
1113-AAC-BUNDLE								31
1113-AAC-BUNDLE								32
477-ACSS-SINGLE								33
1113-AAC-SINGLE								34
1113-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/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.
1431-AAC-BUNDLE								1
1113-AAC- 1431-								2
397.5-AAC-SINGLE								3
3/0-CU-SINGLE 7								4
2/0-CU-SINGLE 3								5
2-ACSR-SINGLE								6
1431-AAC-BUNDLE								7
2300-AAC-BUNDLE								8
397.5-ACSR-SINGL								9
-								10
-CU								11
4/0-AAC-SINGLE								12
4/0-AAC-SINGLE								13
2300-AAC-SINGLE								14
2-CU-SINGLE 3/0								15
1/0-ACSR-SINGLE								16
715.5-AAC-SINGLE								17
4/0-AAC-SINGLE								18
795-ACSS-BUNDLE								19
397.5-AAC-SINGLE								20
1113-AAC-SINGLE								21
397.5-AAC-SINGLE								22
1113-AAC-SINGLE								23
397.5-AAC-SINGLE								24
2300-AAC-SINGLE								25
2300-AAC-BUNDLE								26
3/0-CU-SINGLE 4								27
336.4-AAC-SINGLE								28
336.4-AAC-SINGLE								29
250-CU-SINGLE 7								30
4/0-CU-PARALLEL								31
477-ACSS-SINGLE								32
715.5-AAC-SINGLE								33
715.5-AAC-SINGLE								34
715.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

TRANSMISSION LINE STATISTICS (Continued)

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2/0-CU-SINGLE								1
4/0-AAC-SINGLE								2
1113-ACSS-SINGL								3
1113-AAC-BUNDLE								4
1113-AAC-BUNDLE								5
1/0-ACSR-SINGLE								6
397.5-AAC-SINGLE								7
477-ACSS-SINGLE								8
4/0-AAC-SINGLE								9
3/0-CU-SINGLE 7								10
477-ACSS-SINGLE								11
715.5-AAC-SINGLE								12
477-ACSS-SINGLE								13
4/0-AAC-SINGLE								14
4/0-AAC-SINGLE								15
397.5-AAC-SINGLE								16
266.8-AAC-SINGLE								17
380.5-HOLO-CU-SI								18
715.5-AAC-SINGLE								19
1113-AAC-SINGLE								20
1/0-CU-SINGLE 4								21
795-ACSR-SINGLE								22
1113-AAC-SINGLE								23
1113-AAC-SINGLE								24
1113-AAC-SINGLE								25
3/0-CU-SINGLE								26
266.8-AAC-SINGLE								27
1113-AAC-SINGLE								28
3/0-CU-SINGLE 3								29
1/0-ACSR-SINGLE								30
795-ACSR-SINGLE								31
4/0-ACSR-SINGLE								32
4/0-AAC-SINGLE								33
336.4-ACSR-SINGL								34
2-CU-SINGLE 397								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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500-CU-SINGLE 7								1
1852-ACSR-BUNDL								2
397.5-ACSR-SINGL								3
715.5-AAC-SINGLE								4
250-CU-SINGLE 7								5
250-CU-SINGLE 4								6
477-ACCR-SINGLE								7
397.5-AAC-SINGLE								8
1852-ACSR-BUNDL								9
1113-AAC-BUNDLE								10
1113-AAC-BUNDLE								11
4/0-AAC-SINGLE								12
266.8-AAC-SINGLE								13
266.8-AAC-SINGLE								14
2/0-CU-SINGLE 3								15
2/0-CU-SINGLE 3								16
4/0-AAC-SINGLE								17
2/0-CU-SINGLE 2								18
4/0-CU-SINGLE 4								19
715.5-AAC-SINGLE								20
336.4-ACSR-SINGL								21
1113-AAC-SINGLE								22
397.5-AAC-SINGLE								23
477-ACSS-SINGLE								24
715.5-AAC-SINGLE								25
1/0-ACSR-SINGLE								26
715.5-AAC-SINGLE								27
250-CU-PARALLEL								28
1113-AAC-SINGLE								29
250-CU-SINGLE 3								30
715.5-AAC-SINGLE								31
1113-AAC-SINGLE								32
1113-AAC-SINGLE								33
1113-AAC-SINGLE								34
715.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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2/0-CU-SINGLE 4								1
1/0-ACSR-SINGLE								2
397.5-ACSR-SINGL								3
477-ACSS-SINGLE								4
477-ACSS-SINGLE								5
397.5-ACSR-SINGL								6
1113-AAC-SINGLE								7
477-ACSS-SINGLE								8
336.4-AAC-SINGLE								9
336.4-AAC-SINGLE								10
4/0-AAC-SINGLE								11
2/0-CU-SINGLE 3								12
2/0-CU-SINGLE 4								13
397.5-AAC-PARALL								14
397.5-AAC-SINGLE								15
715.5-AAC-SINGLE								16
250-CU-SINGLE 4								17
715.5-AAC-SINGLE								18
250-CU-SINGLE 3								19
4/0-AAC-SINGLE								20
1113-AAC-SINGLE								21
1113-AAC-SINGLE								22
397.5-ACSR-SINGL								23
715.5-AAC-SINGLE								24
1113-AAC-SINGLE								25
3/0-AAC-SINGLE								26
4/0-AAC-SINGLE								27
3/0-CU-SINGLE 3								28
715.5-AAC-SINGLE								29
397.5-AAC-SINGLE								30
266.8-AAC-SINGLE								31
715.5-AAC-SINGLE								32
1113-AAC-SINGLE								33
4/0-CU-SINGLE 7								34
4/0-AAC-SINGLE								35
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TRANSMISSION LINE STATISTICS (Continued)

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715.5-AAC-BUNDL								1
715.5-AAC-SINGLE								2
397.5-AAC-SINGLE								3
266.8-AAC-PARALL								4
795-ACSR-SINGLE								5
1113-AAC-SINGLE								6
397.5-AAC-SINGLE								7
1-UNKNOWN-UNK								8
250-CU-SINGLE 2								9
4/0-CU-SINGLE 7								10
250-CU-SINGLE 4								11
2300-AAC-SINGLE								12
4/0-AAC-SINGLE								13
954-ACSS-SINGLE								14
266.8-AAC-SINGLE								15
1113-AAC-SINGLE								16
336.4-AAC-SINGLE								17
397.5-AAC-SINGLE								18
4/0-AAC-SINGLE								19
4/0-CU-SINGLE								20
715.5-AAC-SINGLE								21
								22
397.5-AAC-SINGLE								23
477-ACSS-SINGLE								24
477-ACSS-SINGLE								25
4/0-AAC-SINGLE								26
4/0-AAC-SINGLE								27
4/0-AAC-SINGLE								28
397.5-AAC-SINGLE								29
4/0-AAC-SINGLE								30
266.8-AAC-SINGLE								31
2/0-CU-SINGLE 3								32
4/0-AAC-SINGLE								33
266.8-AAC-SINGLE								34
1431-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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)			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-SINGLE								1
2/0-CU-SINGLE 3								2
1/0-ACSR-SINGLE								3
1/0-CU-SINGLE 2								4
397.5-AAC-SINGLE								5
1/0-CU-SINGLE 2								6
397.5-AAC-SINGLE								7
4/0-ACSR-SINGLE								8
2/0-CU-SINGLE 3								9
715.5-AAC-SINGLE								10
477-ACSS-SINGLE								11
1113-AAC-SINGLE								12
954-ACSS-SINGLE								13
1/0-ACSR-SINGLE								14
397.5-AAC-SINGLE								15
715.5-AAC-SINGLE								16
954-ACSS-SINGLE								17
266.8-AAC-PARALL								18
397.5-AAC-SINGLE								19
715.5-AAC-SINGLE								20
397.5-AAC-SINGLE								21
715.5-AAC-SINGLE								22
397.5-AAC-SINGLE								23
397.5-AAC-SINGLE								24
715.5-AAC-SINGLE								25
336.4-AAC-SINGLE								26
2300-AAC-BUNDLE								27
397.5-AAC-SINGLE								28
795-ACSR-SINGLE								29
397.5-ACSR-SINGL								30
397.5-AAC-SINGLE								31
2/0-CU-SINGLE 3								32
1113-AAC-SINGLE								33
2/0-CU-SINGLE 4								34
715.5-AAC-SINGLE								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (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.
1/0-ACSR-SINGLE								1
477-ACSS-SINGLE								2
477-ACSS-SINGLE								3
1113-AAC-SINGLE								4
795-ACSR-SINGLE								5
1/0-ACSR-SINGLE								6
397.5-AAC-SINGLE								7
1113-AAC-SINGLE								8
1113-ACSS-SINGL								9
								10
1000 KCMIL-CU								11
								12
								13
								14
								15
	25,960,202	430,586,995		808,545	7,047,337			16
	69,201,578	1,639,391,071		3,249,354	28,321,595			17
	82,268,017	892,114,585		3,764,047	32,807,694			18
	13,175,263	208,578,347		940,610	8,198,424			19
	30,784,059	486,357,919		2,368,239	20,641,731			20
								21
								22
	2,790,742	238,509,403		1,249,460	97,239			23
	108,545	482,382,062		1,168,419	90,932			24
								25
		19,752,260		112,441	5,260			26
								27
								28
								29
		85,917,419						30
								31
								32
								33
								34
								35
	224,288,406	4,483,590,061		13,661,115	97,210,212			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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: a

Bundled.

Data sources for Page 422-423 data include current ETGIS system, which is being transitioned to full GIS platform for FY2018 reporting.

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.: 1 Column: g

The data for this column (On Structures of another Line) is not available on a circuit-by-circuit basis as the Utility's Geographic Information System (GIS) is in the process of compiling the necessary data at this time.

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

Bundled

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

Bundled

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

Bundled

Schedule Page: 422 Line No.: 5 Column: a

ALUM

Schedule Page: 422 Line No.: 6 Column: a

Bundled

Schedule Page: 422 Line No.: 7 Column: a

Bundled

Schedule Page: 422 Line No.: 8 Column: a

Bundled

Schedule Page: 422 Line No.: 9 Column: a

Bundled

Schedule Page: 422 Line No.: 10 Column: a

Bundled

Schedule Page: 422 Line No.: 11 Column: a

Bundled.

Schedule Page: 422 Line No.: 12 Column: a

Bundled

Schedule Page: 422 Line No.: 13 Column: a

Bundled

Schedule Page: 422 Line No.: 14 Column: a

Bundled

Schedule Page: 422 Line No.: 15 Column: a

Bundled

Schedule Page: 422 Line No.: 16 Column: a

Bundled

Schedule Page: 422 Line No.: 17 Column: a

Bundled

Schedule Page: 422 Line No.: 18 Column: a

Bundled

Schedule Page: 422 Line No.: 19 Column: a

Bundled

Schedule Page: 422 Line No.: 20 Column: a

Bundled

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 21 Column: a
Bundled

Schedule Page: 422 Line No.: 24 Column: a
Bundled

Schedule Page: 422 Line No.: 30 Column: a
Bundled

Schedule Page: 422 Line No.: 32 Column: a
Bundled

Schedule Page: 422.1 Line No.: 3 Column: a
Bundled

Schedule Page: 422.1 Line No.: 34 Column: a
Bundled

Schedule Page: 422.2 Line No.: 13 Column: a
ALUM

Schedule Page: 422.2 Line No.: 14 Column: a
ALUM

Schedule Page: 422.2 Line No.: 15 Column: a
Idle Line

Schedule Page: 422.2 Line No.: 17 Column: a
Alum

Schedule Page: 422.2 Line No.: 25 Column: a
Bundled

Schedule Page: 422.2 Line No.: 28 Column: a
Bundled

Schedule Page: 422.2 Line No.: 31 Column: a
Bundled

Schedule Page: 422.2 Line No.: 35 Column: a
Bundled

Schedule Page: 422.3 Line No.: 1 Column: a
Bundled

Schedule Page: 422.3 Line No.: 2 Column: a
Bundled

Schedule Page: 422.3 Line No.: 7 Column: a
Bundled

Schedule Page: 422.3 Line No.: 8 Column: a
Bundled

Schedule Page: 422.3 Line No.: 11 Column: a
Bundled

Schedule Page: 422.3 Line No.: 12 Column: a
Bundled

Schedule Page: 422.3 Line No.: 17 Column: a
Bundled

Schedule Page: 422.3 Line No.: 18 Column: a
Bundled

Schedule Page: 422.3 Line No.: 20 Column: a
Idle Line

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 422.3 Line No.: 35 Column: a
Bundled
Schedule Page: 422.4 Line No.: 1 Column: a
Bundled
Schedule Page: 422.4 Line No.: 5 Column: a
Bundled
Schedule Page: 422.4 Line No.: 6 Column: a
Bundled
Schedule Page: 422.4 Line No.: 7 Column: a
Bundled
Schedule Page: 422.4 Line No.: 9 Column: a
Bundled
Schedule Page: 422.4 Line No.: 10 Column: a
Bundled
Schedule Page: 422.4 Line No.: 11 Column: a
Bundled
Schedule Page: 422.4 Line No.: 13 Column: a
Bundled
Schedule Page: 422.4 Line No.: 15 Column: a
Bundled
Schedule Page: 422.4 Line No.: 16 Column: a
Bundled
Schedule Page: 422.4 Line No.: 17 Column: a
Bundled
Schedule Page: 422.4 Line No.: 18 Column: a
Bundled
Schedule Page: 422.5 Line No.: 1 Column: a
Bundled
Schedule Page: 422.5 Line No.: 2 Column: a
Bundled
Schedule Page: 422.5 Line No.: 3 Column: a
Bundled
Schedule Page: 422.5 Line No.: 9 Column: a
Bundled
Schedule Page: 422.5 Line No.: 22 Column: a
Idle line
Schedule Page: 422.5 Line No.: 25 Column: a
Bundled
Schedule Page: 422.5 Line No.: 27 Column: a
Bundled
Schedule Page: 422.5 Line No.: 28 Column: a
Bundled
Schedule Page: 422.5 Line No.: 29 Column: a
Bundled
Schedule Page: 422.5 Line No.: 30 Column: a
Bundled
Schedule Page: 422.5 Line No.: 32 Column: a
Bundled

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 422.6 Line No.: 1 Column: a
Bundled
Schedule Page: 422.6 Line No.: 2 Column: a
Bundled
Schedule Page: 422.6 Line No.: 12 Column: a
Bundled
Schedule Page: 422.6 Line No.: 13 Column: a
Bundled
Schedule Page: 422.6 Line No.: 32 Column: a
Bundled
Schedule Page: 422.6 Line No.: 33 Column: a
Bundled
Schedule Page: 422.6 Line No.: 34 Column: a
Bundled
Schedule Page: 422.7 Line No.: 2 Column: a
Bundled
Schedule Page: 422.7 Line No.: 3 Column: a
Bundled
Schedule Page: 422.7 Line No.: 4 Column: a
Bundled
Schedule Page: 422.7 Line No.: 12 Column: a
Bundled
Schedule Page: 422.7 Line No.: 23 Column: a
Bundled
Schedule Page: 422.7 Line No.: 26 Column: a
Bundled
Schedule Page: 422.8 Line No.: 2 Column: a
Alum
Schedule Page: 422.8 Line No.: 32 Column: a
Idle
Schedule Page: 422.8 Line No.: 33 Column: a
Idle
Schedule Page: 422.9 Line No.: 4 Column: a
Idle
Schedule Page: 422.9 Line No.: 5 Column: a
Idle
Schedule Page: 422.9 Line No.: 6 Column: a
Idle
Schedule Page: 422.9 Line No.: 14 Column: a
Bundled
Schedule Page: 422.11 Line No.: 14 Column: a
Bundled
Schedule Page: 422.11 Line No.: 15 Column: a
ALUM
Schedule Page: 422.11 Line No.: 17 Column: a
Bundled
Schedule Page: 422.12 Line No.: 24 Column: a
Bundled
Schedule Page: 422.12 Line No.: 25 Column: a

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/09/2018	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Idle Line

Schedule Page: 422.13 Line No.: 16 Column: a

Idle Line

Schedule Page: 422.14 Line No.: 8 Column: a

Bundled

Schedule Page: 422.14 Line No.: 14 Column: a

Idle Line

Schedule Page: 422.15 Line No.: 17 Column: a

Bundled

Schedule Page: 422.15 Line No.: 24 Column: a

Bundled

Schedule Page: 422.16 Line No.: 4 Column: a

ALUM

Schedule Page: 422.16 Line No.: 5 Column: a

ALUM

Schedule Page: 422.16 Line No.: 27 Column: a

Idle Line

Schedule Page: 422.16 Line No.: 28 Column: a

Idle Line

Schedule Page: 422.16 Line No.: 30 Column: a

Bundled

Schedule Page: 422.16 Line No.: 31 Column: a

Bundled

Schedule Page: 422.17 Line No.: 2 Column: a

Idle Line

Schedule Page: 422.17 Line No.: 10 Column: a

Idle Line

Schedule Page: 422.18 Line No.: 2 Column: a

Bundled

Schedule Page: 422.18 Line No.: 3 Column: a

Bundled

Schedule Page: 422.18 Line No.: 32 Column: a

Idle Line

Schedule Page: 422.19 Line No.: 23 Column: a

Bundled

Schedule Page: 422.19 Line No.: 35 Column: a

Bundled

Schedule Page: 422.20 Line No.: 1 Column: a

Bundled

Schedule Page: 422.20 Line No.: 2 Column: a

Bundled

Schedule Page: 422.20 Line No.: 9 Column: a

Bundled

Schedule Page: 422.20 Line No.: 10 Column: a

Bundled

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 422.20 Line No.: 31 Column: a
Idle Line
Schedule Page: 422.21 Line No.: 10 Column: a
Idle Line
Schedule Page: 422.21 Line No.: 25 Column: a
ALUM
Schedule Page: 422.21 Line No.: 26 Column: a
ALUM
Schedule Page: 422.21 Line No.: 27 Column: a
Alum
Schedule Page: 422.22 Line No.: 5 Column: a
Idle Line
Schedule Page: 422.22 Line No.: 16 Column: a
Idle Line
Schedule Page: 422.22 Line No.: 17 Column: a
Idle Line
Schedule Page: 422.22 Line No.: 29 Column: a
Bundled
Schedule Page: 422.22 Line No.: 32 Column: a
ALUM
Schedule Page: 422.23 Line No.: 8 Column: a
Idle Line
Schedule Page: 422.23 Line No.: 9 Column: a
Idle Line
Schedule Page: 422.23 Line No.: 30 Column: a
Bundled
Schedule Page: 422.24 Line No.: 17 Column: a
ALUM
Schedule Page: 422.24 Line No.: 30 Column: a
Idle Line
Schedule Page: 422.25 Line No.: 10 Column: a
ALUM
Schedule Page: 422.25 Line No.: 29 Column: a
ALUM
Schedule Page: 422.26 Line No.: 26 Column: a
Idle Line
Schedule Page: 422.28 Line No.: 5 Column: a
Idle Line
Schedule Page: 422.29 Line No.: 2 Column: a
Idle Line
Schedule Page: 422.29 Line No.: 4 Column: a
Idle Line
Schedule Page: 422.29 Line No.: 13 Column: a
ALUM
Schedule Page: 422.29 Line No.: 16 Column: a
ALUM
Schedule Page: 422.30 Line No.: 3 Column: a

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/09/2018	2017/Q4

FOOTNOTE DATA

Idle Line

Schedule Page: 422.31 Line No.: 4 Column: a

Idle Line

Schedule Page: 422.31 Line No.: 8 Column: a

Idle Line

Schedule Page: 422.31 Line No.: 15 Column: a

Bundled

Schedule Page: 422.31 Line No.: 27 Column: a

Bundled

Schedule Page: 422.31 Line No.: 29 Column: a

Bundled

Schedule Page: 422.31 Line No.: 34 Column: a

Idle Line

Schedule Page: 422.32 Line No.: 2 Column: a

Idle Line

Schedule Page: 422.32 Line No.: 3 Column: a

Bundled

Schedule Page: 422.32 Line No.: 4 Column: a

ALUM

Schedule Page: 422.33 Line No.: 31 Column: a

Idle Line

Schedule Page: 422.33 Line No.: 35 Column: a

Bundled

Schedule Page: 422.35 Line No.: 8 Column: a

ALUM

Schedule Page: 422.36 Line No.: 2 Column: a

Idle Line

Schedule Page: 422.36 Line No.: 24 Column: a

ALUM

Schedule Page: 422.36 Line No.: 26 Column: a

Bundled

Schedule Page: 422.37 Line No.: 9 Column: a

Idle Line

Schedule Page: 422.37 Line No.: 29 Column: a

Idle Line

Schedule Page: 422.38 Line No.: 4 Column: a

Idle Line

Schedule Page: 422.39 Line No.: 1 Column: a

Idle Line

Schedule Page: 422.39 Line No.: 7 Column: a

Idle Line

Schedule Page: 422.39 Line No.: 23 Column: a

Idle Line

Schedule Page: 422.39 Line No.: 26 Column: a

Idle Line

Schedule Page: 422.40 Line No.: 18 Column: a

Bundled

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	03/09/2018	End of 2017/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	RECONDUCTORING WORK						
2	BAFB - Wheatland T						
3	SMARTVILLE	NICOLAUS	5.30	Wood Pole -LDP	19.00	1	1
4	ORDER #74001734						
5							
6	San Bernard - Tejon						
7	TEJON SUB	SAN BENARD	5.80	Wood Pole -LDP	17.00	1	1
8	ORDER #74001118						
9							
10	Salinas T						
11	SALINAS SUB	FORT ORD	3.20	LSP-TSP	11.00	2	2
12	ORDER #74003087						
13							
14	Coalinga #1 and #2						
15	COALINGA	TORNADO JUNCTION	5.30	LDSP	15.00	2	2
16	ORDER #74004406						
17							
18	Kern Tevis Lamot T						
19	ARVIN JUNCTION	LAMONT SUBSTATION	4.70	LDSP	7.00	1	1
20	ORDER #74004406						
21							
22	Balfour Rd Relo Sellers Rd						
23	HERDLYN		3.00	Wood Pole	26.00	1	1
24	ORDER #30811715	BALFOUR					
25							
26							
27	REMOVALS						
28	Brighton-Clayton #1 & #2						
29	Structure A00/001	Structure 050/377	5.30	Standard	6.00	2	2
30	Job Order #74001423						
31							
32	Big Bend-Clayton #1 & #2						
33	Structure 74/551	Structure 086/643	5.90	Standard	8.00	2	2
34	Job Order #74000663						
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		38.50		109.00	12	12

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
715	AAC	TH	60		1,580,759	2,864,597		4,445,356	3
									4
									5
									6
715	AAC	TRI-POST	70		1,315,775	8,056,013		9,371,788	7
									8
									9
									10
715	AAC	Double Circ	60	217,403	8,729,183	1,192,124		10,138,710	11
									12
									13
									14
1113	AAC	Tri-Post	70		1,694,103	3,758,108		5,452,211	15
									16
									17
									18
715	AAC	Susp, Steel	115		217,184	3,222,772		3,439,956	19
									20
									21
									22
N/A	Al	Tri-Post	60			1,389,334		1,389,334	23
									24
									25
									26
									27
									28
3/0	Cu	Removal	115		763,702	2,204,187		2,967,889	29
									30
									31
									32
3/0	Cu	Removal	115		552,635	2,385,864		2,938,499	33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				217,403	14,853,341	25,072,999		40,143,743	44

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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 1 Column: a

Data sources for Page 424-425 data include current ETGIS system, which is being transitioned to full GIS platform for FY2018 reporting.

Schedule Page: 424 Line No.: 11 Column: l

Trails and Roads

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	7th STANDARD SUB, Bakersfield	Distribution	115.00	21.00	
2	AIRWAYS SUB, Fresno, Ca.	Distribution	115.00	12.00	7.20
3	ALHAMBRA SUB, Martinez	Distribution	115.00	12.00	7.20
4	ALLEGHANY SUB, Alleghany	Distribution	60.00	12.00	7.20
5	ALMADEN SUB, San Jose	Distribution	60.00	12.00	7.20
6	ALPAUGH SUB, Tulare	Distribution	115.00	12.00	
7	ALTAMONT SUB, Livermore	Distribution	60.00	4.00	
8	ALTO SUB, Mill Valley	Distribution	60.00	12.00	2.40
9	AMES DISTRIBUTION SUB, Mountain View	Distribution	115.00	12.00	7.20
10	ANDERSON SUB, Anderson	Distribution	60.00	12.00	2.40
11	ANGIOLA SUB, Kings	Distribution	70.00	12.00	7.20
12	ANITA SUB, Chico	Distribution	60.00	12.00	2.40
13	ANNAPOLIS SUB, Annapolis	Distribution	60.00	12.00	2.40
14	ANTELOPE SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
15	ANTLER SUB, Lakehead	Distribution	60.00	12.00	2.40
16	APPLE HILL SUB, Camino	Distribution	115.00	12.00	7.20
17	APPLE HILL SUB, Camino	Distribution	115.00	21.00	7.20
18	ARBUCKLE SUB, ARBUCKLE	Distribution	60.00	12.00	7.20
19	ARCATA SUB, Arcata	Distribution	60.00	12.00	2.40
20	ARCO SUB, Lost Hills	Transmission	230.00	70.00	13.20
21	ARVIN SUB, Arvin	Distribution	70.00	12.00	2.40
22	ASHLAN AVENUE SUB, Fresno	Distribution	230.00	12.00	7.20
23	ATASCADERO SUB, Atascadero	Distribution	115.00	12.00	7.20
24	ATLANTIC SUB, Roseville	Transmission	230.00	60.00	13.20
25	ATLANTIC SUB, Roseville	Transmission	230.00	115.00	13.20
26	ATWATER SUB, Atwater	Distribution	115.00	12.00	7.20
27	AUBERRY SUB, Auberry	Distribution	70.00	12.00	7.20
28	AUBURN SUB, Auburn	Distribution	60.00	12.00	2.40
29	AVENA SUB, Escalon	Distribution	115.00	12.00	
30	AVENAL SUB, Avenal	Distribution	70.00	12.00	
31	BAHIA SUB, Benicia	Distribution	230.00	12.00	7.20
32	BAIR SUB, Redwood City	Transmission	115.00	60.00	13.20
33	BAIR SUB, Redwood City	Transmission	115.00	12.00	7.20
34	BAKERSFIELD SUB, Bakersfield	Distribution	230.00	21.00	7.20
35	BALFOUR SUB, Brentwood	Distribution	60.00	12.00	4.16
36	BANGOR SUB, Bangor	Distribution	60.00	12.00	7.20
37	BANTA SUB, Tracy	Distribution	60.00	12.00	2.40
38	BARRY SUB, Barry	Distribution	60.00	12.00	7.20
39	BARTON SUB, Fresno	Distribution	115.00	12.00	7.20
40	BASALT SUB, Napa	Distribution	60.00	12.00	2.40

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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	BATAVIA SUB, Dixon	Distribution	60.00	12.00	2.40
2	BAY MEADOWS SUB, San Mateo	Distribution	115.00	21.00	7.20
3	BAY MEADOWS SUB, San Mateo	Distribution	115.00	12.00	7.20
4	BAYWOOD SUB, Morro Bay	Distribution	70.00	12.00	2.40
5	BEAR VALLEY SUB, Bear Valley	Distribution	70.00	21.00	7.20
6	BELL SUB, Auburn	Distribution	115.00	12.00	7.20
7	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	12.00	2.40
8	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	4.00	2.40
9	BELLEVUE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
10	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
11	BELLRIDGE 1A SUB, ButtonWillow	Distribution	115.00	4.00	
12	BELLRIDGE 1B SUB, ButtonWillow	Distribution	115.00	4.00	
13	BELMONT SUB, Belmont	Distribution	115.00	12.00	7.20
14	BERESFORD SUB, San Mateo	Distribution	60.00	4.00	
15	BERRENDA A SUB,	Distribution	70.00	4.00	2.40
16	BERRENDA C SUB, Keck's Corner	Distribution	70.00	12.00	2.40
17	BIG BASIN SUB, Santa Cruz	Distribution	60.00	12.00	
18	BIG LAGOON SUB, Big Lagoon Park	Distribution	60.00	12.00	2.40
19	BIG MEADOWS SUB, Greenville	Distribution	60.00	44.00	2.40
20	BIG RIVER SUB, Mendocino	Distribution	60.00	12.00	2.40
21	BIOLA SUB, Biola	Distribution	70.00	12.00	2.40
22	BLACKWELL SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
23	BLUE LAKE SUB, Blue Lake	Distribution	60.00	12.00	2.40
24	BOGARD SUB, Old Station	Distribution	60.00	12.00	
25	BOGUE SUB, Yuba City	Distribution	115.00	12.00	7.20
26	BOLINAS SUB, Boninas	Distribution	60.00	12.00	7.20
27	BONITA SUB, Madera	Distribution	70.00	12.00	7.20
28	BONNIE NOOK SUB, Dutch Flat	Distribution	60.00	12.00	2.40
29	BORDEN SUB, Madera	Transmission	230.00	70.00	13.20
30	BORDEN SUB, Madera	Transmission	230.00	12.00	7.20
31	BORONDA SUB, Salinas	Distribution	60.00	12.00	2.40
32	BOSWELL SUB, Corcoran	Distribution	70.00	12.00	2.40
33	BOWLES SUB, Bowles	Distribution	70.00	12.00	7.20
34	BRENTWOOD SUB, Brentwood	Distribution	230.00	21.00	7.20
35	BRIDGEVILLE SUB, Bridgeville	Transmission	115.00	60.00	13.20
36	BRIDGEVILLE SUB, Bridgeville	Transmission	60.00	12.00	7.20
37	BRIGHTON SUB, Sacramento	Transmission	230.00	115.00	13.20
38	BRITTON SUB, Sunnyvale	Distribution	115.00	12.00	
39	BROWNS VALLEY SUB, Browns Valley	Distribution	60.00	12.00	2.40
40	BRUNSWICK SUB, Grass Valley	Distribution	115.00	12.00	7.20

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1	BUELLTON SUB, Buellton /93427	Distribution	115.00	12.00	7.20
2	BUENA VISTA SUB, Salinas	Distribution	60.00	12.00	7.20
3	BULLARD SUB, Fresno	Distribution	115.00	12.00	7.20
4	BULLARD SUB, Fresno	Distribution	115.00	21.00	7.20
5	BURLINGAME SUB, Burlingame	Distribution	115.00	21.00	7.20
6	BURNEY SUB, Burney	Distribution	60.00	12.00	2.40
7	BUTTE SUB, Chico	Transmission	115.00	60.00	13.20
8	BUTTE SUB, Chico	Transmission	115.00	12.00	7.20
9	CABRILLO SUB, LOMPOC	Distribution	115.00	12.00	7.20
10	CADET SUB, Maricopa	Distribution	70.00	12.00	
11	CAL WATER SUB,	Distribution	115.00	12.00	7.20
12	CALAVERAS CEMENT SUB, San Andreas	Distribution	60.00	12.00	7.20
13	CALFLAX SUB, Huron	Distribution	70.00	12.00	2.40
14	CALIFORNIA AVE SUB, Fresno	Distribution	115.00	12.00	7.20
15	CALISTOGA SUB, Calistoga	Distribution	60.00	12.00	7.20
16	CALPELLA SUB, Calpella	Distribution	115.00	12.00	7.20
17	CAMBRIA SUB, Cambria	Distribution	70.00	12.00	2.40
18	CAMDEN SUB, Riverdale	Distribution	70.00	12.00	2.40
19	CAMP EVERS SUB, Santa Cruz	Distribution	115.00	21.00	7.20
20	CAMPHORA SUB, Monterey	Distribution	60.00	12.00	7.20
21	CAMPHORA SUB, Monterey	Distribution	60.00	4.00	
22	CANAL SUB, Los Banos	Distribution	70.00	12.00	7.20
23	CANTUA SUB, Cantua Creek	Distribution	115.00	12.00	
24	CAPAY SUB, Orland	Distribution	60.00	12.00	2.40
25	CARBONA SUB, Tracy	Distribution	60.00	12.00	7.20
26	CARLOTTA SUB, Carlotta	Distribution	60.00	12.00	2.40
27	CARNATION SUB, Bakersfield	Distribution	70.00	21.00	7.20
28	CARNERAS SUB, Blackwells Corner	Distribution	70.00	12.00	7.20
29	CAROLANDS SUB, Hillsborough	Distribution	60.00	4.00	
30	CARQUINEZ SUB, Vallejo	Distribution	115.00	12.00	2.40
31	CARRIZO PLAINS SUB, Carrizo Plains	Distribution	115.00	12.00	2.40
32	CARUTHERS SUB, Fresno	Distribution	70.00	12.00	2.40
33	CASCADE SUB, Pine Grove	Transmission	115.00	60.00	13.20
34	CASSIDY SUB, Madera	Distribution	70.00	12.00	2.40
35	CASTRO VALLEY SUB, Castro Valley	Distribution	230.00	12.00	
36	CASTROVILLE SUB, Castroville	Distribution	115.00	21.00	7.20
37	CATLETT SUB, Pleasant Grove	Distribution	60.00	12.00	
38	CAWELO B SUB, Famosa	Distribution	70.00	4.00	
39	CAWELO C SUB, Famosa	Distribution	115.00	4.00	
40	CAYETANO SUB, Danville	Distribution	230.00	21.00	7.20

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1	CAYUCOS SUB, Cayucos	Distribution	70.00	12.00	7.20
2	CEDAR CREEK SUB, Round Mountain	Distribution	60.00	12.00	2.40
3	CELERON HILL SUB, N. Belridge	Distribution	70.00	12.00	
4	CHALLENGE SUB, Challenge	Distribution	60.00	12.00	2.40
5	CHANNEL SUB, Stockton	Distribution	60.00	12.00	
6	CHARCA SUB, Wasco	Distribution	115.00	12.00	7.20
7	CHENEY SUB, Mendota	Distribution	115.00	12.00	7.20
8	CHEROKEE SUB, Stockton	Distribution	60.00	12.00	7.20
9	CHESTER SUB, Plumas	Distribution	60.00	13.80	
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	CHRISTIE SUB, Hercules	Transmission	115.00	60.00	13.20
16	CLARK ROAD SUB, Paradise	Distribution	60.00	12.00	2.40
17	CLARKSVILLE SUB, Clarksville	Distribution	115.00	21.00	7.20
18	CLAY SUB, Ione	Distribution	60.00	12.00	2.40
19	CLAYTON SUB, Concord	Distribution	115.00	21.00	7.20
20	CLAYTON SUB, Concord	Distribution	115.00	12.00	7.20
21	CLEAR LAKE SUB, Finley	Distribution	60.00	12.00	2.40
22	CLOVERDALE SUB, Cloverdale	Distribution	115.00	12.00	7.20
23	CLOVIS SUB, Clovis	Distribution	115.00	12.00	7.20
24	CLOVIS SUB, Clovis	Distribution	115.00	21.00	7.20
25	COALINGA #1 SUB, Coalinga	Distribution	70.00	12.00	7.20
26	COALINGA #2 SUB, Coalinga	Distribution	70.00	12.00	2.40
27	COARSEGOLD SUB, Coursegold	Distribution	115.00	21.00	7.20
28	COBURN SUB, King City	Transmission	230.00	60.00	13.20
29	COLONY SUB, Lodi	Distribution	60.00	12.00	2.40
30	COLUMBIA HILL SUB, Sweetland	Distribution	60.00	12.00	2.40
31	COLUMBUS SUB, Bakersfield	Distribution	115.00	12.00	7.20
32	COLUSA JUNCT SUB, Colusa	Distribution	60.00	12.00	7.20
33	COLUSA SUB, Colusa	Distribution	60.00	12.00	
34	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	60.00	13.20
35	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	115.00	13.20
36	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	21.00	7.20
37	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	21.00	6.60
38	COOLEY LANDING SUB, Palo Alto	Transmission	115.00	60.00	13.80
39	COPPERMINE SUB, Clovis	Distribution	70.00	12.00	2.40
40	COPUS SUB, Bakersfield	Distribution	70.00	12.00	

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1	CORCORAN SUB, Corcoran	Transmission	115.00	70.00	13.20
2	CORCORAN SUB, Corcoran	Transmission	115.00	12.00	7.20
3	CORDELIA SUB, Cordelia	Distribution	115.00	12.00	7.20
4	CORDELIA SUB, Cordelia	Distribution	60.00	12.00	2.40
5	CORNING SUB, Corning	Distribution	60.00	12.00	2.40
6	CORONA SUB,	Distribution	115.00	12.00	7.20
7	CORRAL SUB, Bellota	Distribution	60.00	12.00	7.20
8	CORTINA SUB, Williams	Transmission	115.00	60.00	13.20
9	CORTINA SUB, Williams	Transmission	230.00	115.00	13.20
10	CORTINA SUB, Williams	Transmission	115.00	12.00	7.20
11	COTATI SUB, Cotati	Distribution	60.00	12.00	
12	COTTLE SUB, Oakdale	Distribution	230.00	17.00	
13	COTTONWOOD SUB, Cottonwood	Transmission	230.00	60.00	13.20
14	COTTONWOOD SUB, Cottonwood	Transmission	230.00	115.00	13.20
15	COTTONWOOD SUB, Cottonwood	Transmission	115.00	12.00	7.20
16	COUNTRY CLUB SUB, Stockton	Distribution	60.00	12.00	
17	COUNTRY CLUB SUB, Stockton	Distribution	60.00	4.00	
18	COVELO SUB, Covelo	Distribution	60.00	12.00	2.40
19	CRESSEY SUB, Merced	Distribution	115.00	21.00	
20	CROWS LANDING SUB, Crows Landing	Distribution	60.00	12.00	2.40
21	CRUSHER SUB, Bonny Doon	Distribution	60.00	4.00	
22	CRYSTAL SPRINGS SUB, San Mateo	Distribution	60.00	4.00	
23	CURTIS SUB, Sonora	Distribution	115.00	18.00	
24	CUYAMA SUB, Cuyama	Distribution	70.00	12.00	
25	CUYAMA SUB, Cuyama	Distribution	70.00	21.00	7.20
26	CYMRIC SUB, McKitrick	Distribution	115.00	12.00	7.20
27	DAIRYLAND SUB, Chowchilla	Distribution	115.00	12.00	7.20
28	DAIRYVILLE SUB, Dairyville	Distribution	60.00	12.00	2.40
29	DALY CITY SUB, Daly City	Distribution	115.00	12.00	7.20
30	DAVIS SUB, Davis	Distribution	115.00	12.00	7.20
31	DEEPWATER SUB, W. Sactramento	Distribution	115.00	12.00	7.20
32	DEL MAR SUB, Rocklin	Distribution	60.00	21.00	7.20
33	DEL MAR SUB, Rocklin	Distribution	60.00	12.00	7.20
34	DEL MONTE SUB, Monterey	Transmission	115.00	60.00	13.20
35	DEL MONTE SUB, Monterey	Transmission	115.00	21.00	7.20
36	DERRICK SUB, Kettleman	Distribution	70.00	12.00	2.40
37	DESCHUTES SUB, Palo Cedro	Distribution	60.00	12.00	7.20
38	DEVILS DEN SUB, Avenal	Distribution	70.00	12.00	2.40
39	DIAMOND SPRINGS SUB, Placerville	Distribution	115.00	12.00	7.20
40	DINUBA SUB, Dinuba	Distribution	70.00	12.00	7.20

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1	DIVIDE SUB, Orcutt	Transmission	115.00	70.00	13.20
2	DIVIDE SUB, Orcutt	Transmission	70.00	12.00	2.40
3	DIVIDE SUB, Orcutt	Transmission	115.00	12.00	7.20
4	DIXON LANDING SUB,	Distribution	115.00	21.00	7.20
5	DIXON SUB, Dixon	Distribution	60.00	12.00	
6	DOBBINS SUB, Dobbins	Distribution	60.00	12.00	2.40
7	DOLAN ROAD SUB, Moss Landing	Distribution	115.00	12.00	
8	DOS PALOS SUB, Dos Palos	Distribution	70.00	12.00	7.20
9	DRAKE SUB, Arbuckle	Distribution	60.00	2.00	2.40
10	DUMBARTON SUB, Fremont	Distribution	115.00	12.00	
11	DUNBAR SUB, Glen Ellen	Distribution	60.00	12.00	
12	DUNLAP SUB, Fresno	Distribution	70.00	12.00	
13	DUNNIGAN SUB, Dunnigan	Distribution	60.00	12.00	2.40
14	EAGLE ROCK SUB, Geysers	Transmission	115.00	60.00	
15	EAST GRAND SUB, So San Fran.	Distribution	115.00	12.00	7.20
16	EAST MARYSVILLE SUB, Marysville,	Distribution	115.00	12.00	7.20
17	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	60.00	
18	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	12.00	
19	EAST QUINCY SUB, Quincy	Distribution	60.00	12.00	2.40
20	EAST STOCKTON SUB, Stockton	Distribution	60.00	12.00	7.20
21	EAST STOCKTON SUB, Stockton	Distribution	60.00	4.00	
22	EASTSHORE SUB, Hayward	Transmission	230.00	115.00	
23	EDENVALE SUB, San Jose	Distribution	115.00	21.00	7.20
24	EDENVALE SUB, San Jose	Distribution	115.00	12.00	7.20
25	EDES SUB, Oakland	Distribution	115.00	12.00	7.20
26	EEL RIVER SUB, Ferndale	Distribution	60.00	12.00	7.20
27	EIGHT MILE SUB, Stockton	Distribution	230.00	21.00	7.20
28	EL CAPITAN SUB, Snelling	Distribution	115.00	12.00	
29	EL CAPITAN SUB, Snelling	Distribution	115.00	21.00	
30	EL CERRITO G SUB, El Cerrito	Distribution	115.00	12.00	
31	EL NIDO SUB, Merced	Distribution	115.00	12.00	7.20
32	EL PATIO SUB, Campbell	Distribution	115.00	12.00	7.20
33	EL PECO SUB, Madera	Distribution	70.00	12.00	
34	ELECTRA SUB,	Distribution	60.00	12.00	
35	ELK CREEK SUB, Elk Creek	Distribution	60.00	12.00	2.40
36	ELK HILLS SUB, Valley Acres	Distribution	70.00	12.00	
37	ELK SUB, Elk	Distribution	60.00	12.00	2.40
38	EMERALD LAKE SUB, Emerald Lake	Distribution	60.00	4.00	2.40
39	ENCINAL SUB, Live Oak	Distribution	60.00	2.00	2.40
40	ERTA SUB, Watsonville	Distribution	60.00	4.00	

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1	ESQUON SUB, Durham	Distribution	60.00	12.00	2.40
2	EUREKA A SUB, Eureka	Distribution	60.00	12.00	7.20
3	EUREKA E SUB, Eureka	Distribution	60.00	12.00	
4	EVERGREEN SUB, San Jose	Transmission	115.00	60.00	13.20
5	EVERGREEN SUB, San Jose	Transmission	115.00	21.00	7.20
6	FAIRHAVEN SUB, Fairhaven	Distribution	60.00	12.00	7.20
7	FAIRVIEW SUB, Martinez	Distribution	115.00	21.00	12.00
8	FAIRWAY SUB, Santa Maria	Distribution	115.00	12.00	7.20
9	FAMOSO SUB, Famosa	Distribution	115.00	12.00	
10	FELLOWS SUB, Fellows	Distribution	115.00	21.00	
11	FIGARDEN SUB, Fresno	Distribution	230.00	21.00	7.20
12	FIREBAUGH SUB, Firebaugh	Distribution	70.00	12.00	7.20
13	FITCH MOUNTAIN SUB, Healdsburg	Distribution	60.00	12.00	7.20
14	FLINT SUB, Auburn	Distribution	115.00	12.00	7.20
15	FMC SUB, San Jose	Distribution	115.00	12.00	7.20
16	FOOTHILL SUB, SLO	Distribution	115.00	12.00	2.40
17	FORESTHILL SUB, Foresthill,	Distribution	60.00	12.00	7.20
18	FORT BRAGG A SUB, Fort Bragg	Distribution	60.00	12.00	
19	FORT ORD SUB, Fort Ord	Distribution	60.00	21.00	7.20
20	FORT ORD SUB, Fort Ord	Distribution	60.00	12.00	2.40
21	FORT ROSS SUB, Fort Ross	Distribution	60.00	12.00	2.40
22	FORT SEWARD SUB, Fort Seward	Distribution	60.00	12.00	2.40
23	FRANKLIN SUB, Hercules	Distribution	60.00	12.00	7.20
24	FREMONT SUB, Fremont	Distribution	115.00	12.00	7.20
25	FRENCH CAMP SUB, Stockton	Distribution	60.00	12.00	
26	FRENCH GULCH SUB, French Gulch	Distribution	60.00	12.00	2.40
27	FROGTOWN SUB, Angels Camp	Distribution	115.00	17.00	
28	FRUITLAND SUB, Myers Flat	Distribution	60.00	12.00	2.40
29	FRUITVALE SUB, Bakersfield	Distribution	70.00	12.00	2.40
30	FULTON SUB, Fulton	Transmission	115.00	60.00	13.20
31	FULTON SUB, Fulton	Transmission	230.00	115.00	13.20
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	GARCIA SUB, Point Arena	Distribution	60.00	4.00	2.40
39	GARDNER SUB, Taft	Distribution	70.00	4.00	
40	GATES SUB, Huron	Transmission	115.00	70.00	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	03/09/2018	End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	GATES SUB, Huron	Transmission	230.00	115.00	13.20
2	GATES SUB, Huron	Transmission	500.00	230.00	13.20
3	GATES SUB, Huron	Transmission	230.00	12.00	7.20
4	GATES SUB, Huron	Transmission	115.00	12.00	
5	GERBER SUB, Gerber	Distribution	60.00	12.00	2.40
6	GEYSERVILLE SUB, Geyserville	Distribution	60.00	12.00	2.40
7	GIFFEN SUB, San Joaquin	Distribution	70.00	12.00	2.40
8	GIRVAN SUB, Redding	Distribution	60.00	12.00	7.20
9	GLENN SUB, Orland	Transmission	230.00	60.00	13.20
10	GLENN SUB, Orland	Transmission	60.00	12.00	
11	GLENWOOD SUB, Menlo Park	Distribution	60.00	12.00	7.20
12	GLENWOOD SUB, Menlo Park	Distribution	60.00	4.00	
13	GOLD HILL SUB, Folsom	Transmission	115.00	60.00	13.20
14	GOLD HILL SUB, Folsom	Transmission	230.00	115.00	13.20
15	GOLDTREE SUB, SLO	Distribution	115.00	12.00	7.20
16	GONZALES SUB, Gonzales	Distribution	60.00	12.00	
17	GOOSE LAKE SUB, Wasco	Distribution	115.00	12.00	7.20
18	GRAND ISLAND SUB, Ryde	Distribution	115.00	21.00	7.20
19	GRANT SUB, San Lorenzo	Distribution	115.00	12.00	7.20
20	GRASS VALLEY SUB, Grass Valley	Distribution	60.00	12.00	
21	GRAYS FLAT SUB, Twain	Distribution	60.00	4.00	2.40
22	GREEN VALLEY SUB, Watsonville	Transmission	115.00	60.00	
23	GREEN VALLEY SUB, Watsonville	Transmission	115.00	21.00	7.20
24	GREENBRAE SUB, Larkspur	Distribution	60.00	12.00	7.20
25	GUALALA SUB, Gualala	Distribution	60.00	12.00	2.40
26	GUERNSEY SUB, Hanford	Distribution	70.00	12.00	
27	GUSTINE SUB, Gustine	Distribution	60.00	12.00	7.20
28	HALF MOON BAY SUB, Half Moon Bay	Distribution	60.00	12.00	2.40
29	HAMILTON SUB,	Distribution	60.00	12.00	2.40
30	HAMMER SUB, Stockton	Distribution	60.00	12.00	7.20
31	HAMMONDS SUB, Fresno	Distribution	115.00	12.00	
32	HARDING SUB, Stockton	Distribution	60.00	4.00	
33	HARDWICK SUB, Layton	Distribution	70.00	12.00	7.20
34	HARRINGTON SUB, Arbuckle	Distribution	60.00	2.00	
35	HARRIS SUB, Eureka	Distribution	60.00	12.00	7.20
36	HARTER SUB, Yuba City	Distribution	60.00	12.00	7.20
37	HARTLEY SUB, Lakeport	Distribution	60.00	12.00	7.20
38	HATTON SUB, Carmel Valley	Distribution	60.00	12.00	2.40
39	HELM SUB, San Joaquin	Transmission	230.00	70.00	13.20
40	HENRIETTA SUB, Lamoore	Transmission	230.00	70.00	13.20

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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	HENRIETTA SUB, Lamoore	Transmission	230.00	115.00	2.40
2	HENRIETTA SUB, Lemoore	Transmission	70.00	12.00	2.40
3	HERDLYN SUB, Tracy	Transmission	70.00	60.00	2.40
4	HERDLYN SUB, Tracy	Transmission	60.00	12.00	2.40
5	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20
6	HICKS SUB, San Jose	Distribution	230.00	21.00	7.20
7	HICKS SUB, San Jose	Distribution	230.00	12.00	7.20
8	HIGGINS SUB, Higgins Corner	Distribution	115.00	12.00	7.20
9	HIGHLANDS SUB, Clear Lake	Distribution	115.00	12.00	7.20
10	HIGHWAY SUB, Petaluma	Distribution	115.00	12.00	7.20
11	HILLSDALE SUB, San Mateo	Distribution	60.00	4.00	2.40
12	HOLLISTER SUB, Hollister	Distribution	115.00	21.00	7.20
13	HOLLISTER SUB, Hollister	Distribution	60.00	21.00	
14	HONCUT SUB, Honcut	Distribution	115.00	12.00	7.20
15	HOOPA SUB, Hoopa	Distribution	60.00	12.00	2.40
16	HOPLAND SUB, Hopland	Transmission	115.00	60.00	13.20
17	HOPLAND SUB, Hopland	Transmission	60.00	12.00	2.40
18	HORSESHOE SUB, Granite Bay	Distribution	115.00	12.00	7.20
19	HOWLAND ROAD SUB, Manteca	Distribution	115.00	12.00	7.20
20	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	13.80	
21	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	13.80	
22	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	12.00	7.20
23	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	2.00	
24	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	2.00	
25	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
26	HURON SUB, Huron	Distribution	70.00	12.00	2.40
27	IGNACIO SUB, Ignacio	Transmission	115.00	60.00	13.20
28	IGNACIO SUB, Ignacio	Transmission	230.00	115.00	13.20
29	IGNACIO SUB, Ignacio	Transmission	115.00	12.00	
30	IMHOFF SUB, Martinez	Distribution	115.00	12.00	7.20
31	INDIAN FLAT SUB, Incline	Distribution	70.00	12.00	
32	INDUSTRIAL ACRES SUB, Salinas	Distribution	60.00	4.00	
33	IONE SUB, Ione	Distribution	60.00	12.00	7.20
34	IUKA SUB, Pleasanton	Distribution	60.00	4.00	
35	JACALITOS SUB,	Distribution	70.00	12.00	2.40
36	JACINTO SUB, Willows	Distribution	60.00	12.00	7.20
37	JACOBS CORNER SUB, Lemoore	Distribution	70.00	12.00	2.40
38	JAMESON SUB, CORDELIA	Distribution	115.00	12.00	7.20
39	JANES CREEK SUB, Arcata	Distribution	60.00	12.00	7.20
40	JARVIS SUB, Union City	Distribution	115.00	12.00	7.20

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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	JEFFERSON SUB, Redwood City	Transmission	230.00	60.00	13.20
2	JESSUP SUB, Anderson	Distribution	115.00	12.00	
3	JOLON SUB, King City	Distribution	60.00	12.00	
4	KANAKA SUB, Feather Falls	Distribution	115.00	12.00	7.20
5	KASSON SUB, Tracy	Transmission	115.00	60.00	13.20
6	KELSO SUB, Tracy	Distribution	230.00	12.00	
7	KERMAN SUB, Kerman	Distribution	70.00	12.00	7.20
8	KERN OIL SUB, Bakersfield	Distribution	115.00	12.00	7.20
9	KERN PP DIST SUB, Bakersfield	Distribution	115.00	21.00	7.20
10	KERN PP SUB, Bakersfield	Transmission	115.00	70.00	13.20
11	KERN PP SUB, Bakersfield	Transmission	230.00	115.00	13.20
12	KERN WATER SUB, Bakersfield	Distribution	115.00	4.00	
13	KESWICK SUB, Keswick	Distribution	60.00	12.00	2.40
14	KETTLEMAN HILLS SUB, Kettleman	Distribution	70.00	12.00	2.40
15	KING CITY SUB, King City	Distribution	60.00	12.00	
16	KINGSBURG SUB, Kingsburg	Transmission	115.00	70.00	13.80
17	KINGSBURG SUB, Kingsburg	Transmission	115.00	12.00	7.20
18	KIRKER SUB, Pittsburg	Distribution	115.00	21.00	7.20
19	KNIGHTS LANDING SUB, Knights Landing	Distribution	115.00	12.00	
20	KONOCTI SUB, Clear Lake	Distribution	60.00	12.00	2.40
21	LAGUNITAS SUB, Salinas	Distribution	60.00	2.40	
22	LAKEVIEW SUB, Bakersfield	Distribution	70.00	12.00	2.40
23	LAKEVILLE SUB, Petaluma	Transmission	230.00	60.00	13.20
24	LAKEVILLE SUB, Petaluma	Transmission	230.00	115.00	13.20
25	LAKEVILLE SUB, Petaluma	Transmission	115.00	12.00	7.20
26	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	21.00	7.20
27	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	12.00	7.20
28	LAMMERS SUB, TRACY	Distribution	115.00	12.00	7.20
29	LAMONT SUB, Bakersfield	Distribution	115.00	12.00	
30	LAS GALLINAS A SUB, Las Gallinas	Distribution	115.00	12.00	7.20
31	LAS PALMAS SUB, Fresno	Distribution	115.00	12.00	7.20
32	LAS POSITAS SUB, Livermore	Transmission	230.00	60.00	13.20
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	LAURELES SUB, Carmel	Distribution	60.00	12.00	
36	LAWRENCE SUB, Sunnyvale	Distribution	115.00	12.00	7.20
37	LAYTONVILLE SUB, Laytonville,	Distribution	60.00	12.00	2.40
38	LE GRAND SUB, Le Grand	Distribution	115.00	12.00	7.20
39	LEARNER SUB, Stockton	Distribution	60.00	4.00	
40	LEMOORE SUB, Armonia	Distribution	70.00	12.00	2.40

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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	LERDO SUB, Bakersfield	Distribution	115.00	12.00	7.20
2	LIMESTONE SUB, Shingle Springs	Distribution	60.00	2.00	
3	LINCOLN SUB, Lincoln	Distribution	115.00	12.00	7.20
4	LINDEN SUB, Linden	Distribution	60.00	12.00	2.40
5	LIVE OAK SUB, Live Oak	Distribution	60.00	12.00	
6	LIVERMORE SUB, Livermore	Distribution	60.00	12.00	2.40
7	LIVINGSTON SUB, Livingston	Distribution	115.00	12.00	7.20
8	LIVINGSTON SUB, Livingston	Distribution	70.00	12.00	
9	LLAGAS SUB, Gilroy	Distribution	115.00	21.00	12.00
10	LOCKEFORD SUB, Lockeford	Transmission	230.00	60.00	13.20
11	LOCKEFORD SUB, Lockeford	Transmission	115.00	21.00	7.20
12	LOCKHEED #1 SUB, Sunnyvale	Distribution	115.00	12.00	7.20
13	LOCKHEED #2 SUB, Sunnyvale	Distribution	115.00	12.00	
14	LODI SUB, Lodi	Distribution	60.00	12.00	2.40
15	LODI SUB, Lodi	Distribution	60.00	4.00	
16	LOGAN CREEK SUB, Willows	Distribution	230.00	21.00	
17	LONETREE SUB, Antioch	Distribution	230.00	21.00	7.20
18	LOS ALTOS SUB, Los Altos	Distribution	60.00	12.00	
19	LOS BANOS SUB, Los Banos	Transmission	230.00	70.00	13.20
20	LOS BANOS SUB, Los Banos	Transmission	500.00	230.00	13.80
21	LOS COCHES SUB, Greenfield	Distribution	60.00	12.00	
22	LOS ESTEROS SUB,	Transmission	230.00	115.00	12.00
23	LOS GATOS SUB, Los Gatos	Distribution	60.00	12.00	7.20
24	LOS MOLINOS SUB, Los Molinos	Distribution	60.00	12.00	7.20
25	LOS OSITOS SUB, Monterey	Distribution	60.00	21.00	7.20
26	LOST HILLS SUB, Blackwell Corners	Distribution	70.00	12.00	2.40
27	LOW GAP SUB, Mad River	Distribution	60.00	12.00	
28	LOYOLA SUB, Loyola	Distribution	60.00	12.00	7.20
29	LOYOLA SUB, Loyola	Distribution	60.00	4.00	2.40
30	LUCERNE SUB, Lucerne	Distribution	115.00	12.00	7.20
31	MABURY SUB, San Jose	Distribution	60.00	12.00	2.40
32	MABURY SUB, San Jose	Distribution		12.00	7.20
33	MADERA SUB, Madera	Distribution	70.00	12.00	
34	MADISON SUB, Madison	Distribution	60.00	12.00	7.20
35	MADISON SUB, Madison	Distribution	115.00	12.00	
36	MAGUNDEN SUB, Bakersfield	Distribution	115.00	12.00	7.20
37	MAGUNDEN SUB, Bakersfield	Distribution	115.00	21.00	7.20
38	MAINE PRAIRIE SUB, DIXON	Distribution	60.00	4.00	2.40
39	MALAGA SUB, Fresno	Distribution	115.00	12.00	7.20
40	MANCHESTER SUB, Fresno	Distribution	115.00	12.00	7.20

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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	MANTECA SUB, Manteca	Transmission	115.00	60.00	13.20
2	MANTECA SUB, Manteca	Transmission	115.00	17.00	
3	MANZANITA SUB, Seaside	Distribution	60.00	4.00	
4	MAPLE CREEK SUB, Blue Lake	Distribution	60.00	12.00	2.40
5	MARICOPA SUB, Maricopa	Distribution	70.00	12.00	2.40
6	MARIPOSA SUB, Mariposa	Distribution	70.00	21.00	
7	MARSH SUB, Brentwood	Distribution	60.00	12.00	2.40
8	MARTELL SUB, Martell	Distribution	60.00	12.00	2.40
9	MARYSVILLE SUB, Marysville	Distribution	60.00	12.00	
10	MAXWELL SUB, Maxwell	Distribution	60.00	12.00	
11	MCARTHUR SUB, McArthur	Distribution	60.00	12.00	2.40
12	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
13	MCCALL SUB, Selma	Transmission	115.00	12.00	7.20
14	MCDONALD-MCDONALDISLAND SUB, Stockton	Distribution	60.00	4.00	2.40
15	MCFARLAND SUB, McFarland	Distribution	70.00	12.00	7.20
16	MCKEE SUB, San Jose	Distribution	115.00	12.00	7.20
17	MCKITTRICK SUB, MCKITTRICK	Distribution	70.00	12.00	
18	MCMULLIN SUB, Fresno	Distribution	230.00	12.00	7.20
19	MEADOW LANE SUB, Concord	Distribution	115.00	21.00	7.20
20	MENDOCINO SUB, Redwood Valley	Transmission	115.00	60.00	13.20
21	MENDOCINO SUB, Redwood Valley	Transmission	60.00	12.00	2.40
22	MENDOTA SUB, Mendota	Transmission	115.00	70.00	12.00
23	MENDOTA SUB, Mendota	Transmission	115.00	12.00	7.20
24	MENLO SUB, Menlo Park	Distribution	60.00	12.00	7.20
25	MENLO SUB, Menlo Park	Distribution	60.00	4.00	
26	MERCED SUB, Merced	Transmission	115.00	70.00	6.60
27	MERCED SUB, Merced	Transmission	115.00	12.00	7.20
28	MERCED SUB, Merced	Transmission	115.00	21.00	7.20
29	MERCY SPRINGS SUB, Los Banos	Distribution	60.00	12.00	2.40
30	MERIDIAN SUB, Meridian	Distribution	60.00	12.00	
31	MESA SUB, Nipomo	Transmission	230.00	115.00	13.20
32	MESA SUB, Nipomo	Transmission	230.00	12.00	
33	METCALF SUB, San Jose	Transmission	500.00	230.00	13.80
34	METCALF SUB, San Jose	Transmission	230.00	115.00	13.20
35	METTLER SUB, Stockton	Distribution	60.00	12.00	
36	MIDDLE RIVER SUB, Stockton	Distribution	60.00	12.00	2.40
37	MIDDLETOWN SUB, Middletown	Distribution	60.00	12.00	7.20
38	MIDWAY SUB, Buttonwillow	Transmission	230.00	115.00	13.20
39	MIDWAY SUB, Buttonwillow	Transmission	500.00	230.00	13.80
40	MIDWAY SUB, Buttonwillow	Transmission	115.00	12.00	7.20

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1	MILLBRAE SUB, Millbrae	Transmission	115.00	60.00	13.80
2	MILLBRAE SUB, Millbrae	Transmission	115.00	12.00	
3	MILLBRAE SUB, Millbrae	Transmission	60.00	4.00	
4	MILPITAS SUB, Milpitas	Distribution	115.00	21.00	7.20
5	MILPITAS SUB, Milpitas	Distribution	115.00	12.00	7.20
6	MIRABEL SUB, Forestville	Distribution	60.00	12.00	
7	MI-WUK SUB, Sugarpine	Distribution	115.00	17.00	
8	MOLINO SUB, Sebastopol	Distribution	60.00	12.00	7.20
9	MONARCH SUB, Stockton	Distribution	60.00	4.00	2.40
10	MONROE SUB, Santa Rosa	Distribution	115.00	21.00	7.20
11	MONROE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
12	MONTA VISTA SUB, Cupertino	Transmission	115.00	60.00	13.20
13	MONTA VISTA SUB, Cupertino	Transmission	230.00	60.00	
14	MONTA VISTA SUB, Cupertino	Transmission	230.00	115.00	13.20
15	MONTAGUE SUB, San Jose	Distribution	115.00	21.00	7.20
16	MONTE RIO SUB, Monte Rio	Distribution	60.00	12.00	7.20
17	MONTEREY SUB, Monterey	Distribution	60.00	4.00	
18	MONTICELLO SUB, Winters	Distribution	115.00	12.00	
19	MORAGA SUB, Orinda	Transmission	230.00	115.00	13.20
20	MORAGA SUB, Orinda	Transmission	115.00	12.00	
21	MORGAN HILL SUB, Morgan Hill	Distribution	115.00	21.00	7.20
22	MORMON SUB, Stockton	Distribution	60.00	12.00	7.20
23	MORRO BAY PP SWYD, Morro Bay	Transmission	230.00	115.00	13.20
24	MORRO BAY PP SWYD, Morro Bay	Transmission	115.00	12.00	7.20
25	MOSHER SUB, Stockton	Distribution	60.00	21.00	7.20
26	MOSS LANDING PP SUB, Moss Landing	Transmission	230.00	115.00	13.20
27	MOSS LANDING PP SUB, Moss Landing	Transmission	500.00	230.00	13.80
28	MOUNTAIN VIEW SUB, Mt. View	Distribution	115.00	12.00	7.20
29	MT. EDEN SUB, Hayward	Distribution	115.00	12.00	7.20
30	MT. QUARRIES SUB, Cool	Distribution	60.00	12.00	7.20
31	NAPA SUB, Napa	Distribution	60.00	12.00	
32	NARROWS SUB,	Distribution	60.00	21.00	7.20
33	NAVY LAB SUB, Monterey	Distribution	60.00	4.00	
34	NAVY SCHOOL SUB, Monterey	Distribution	60.00	4.00	
35	NEW HOPE SUB, Lodi	Distribution	60.00	12.00	2.40
36	NEW KEARNEY SUB, FRESNO	Transmission	230.00	70.00	13.20
37	NEWARK DIST SUB, Fremont	Distribution	230.00	21.00	7.20
38	NEWARK SUB, Fremont	Transmission	115.00	60.00	13.20
39	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
40	NEWARK SUB, Fremont	Transmission	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	03/09/2018	End of 2017/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	NEWBURG SUB, Fortuna	Distribution	60.00	12.00	2.40
2	NEWHALL SUB, Firebaugh	Distribution	115.00	12.00	7.20
3	NEWMAN SUB, Newman	Distribution	60.00	12.00	7.20
4	NORCO SUB, Bakersfield	Distribution	115.00	12.00	7.20
5	NORD SUB, Chico	Distribution	115.00	12.00	7.20
6	NORTECH SUB, San Jose	Distribution	115.00	21.00	7.20
7	NORTH BRANCH SUB, San Andreas	Distribution	60.00	12.00	2.40
8	NORTH DUBLIN SUB, Pleasanton	Distribution	230.00	21.00	12.00
9	NORTH TOWER SUB, Vallejo	Distribution	115.00	12.00	7.20
10	NOTRE DAME SUB, Chico	Distribution	115.00	12.00	7.20
11	NOVATO SUB, Novato	Distribution	60.00	12.00	7.20
12	OAK PARK SUB, Stockton	Distribution	60.00	4.00	
13	OAKHURST SUB, Oakhurst	Distribution	115.00	12.00	2.40
14	OAKLAND C (OAKLAND PP) SUB, Oakland	Distribution	115.00	12.00	7.20
15	OAKLAND D SUB, Oakland	Distribution	115.00	12.00	7.20
16	OAKLAND J SUB, Oakland	Distribution	115.00	12.00	7.20
17	OAKLAND K (CLAREMONT) SUB, Oakland	Distribution	115.00	12.00	6.60
18	OAKLAND L SUB, Oakland	Distribution	115.00	12.00	7.20
19	OAKLAND X SUB, Oakland	Distribution	115.00	12.00	7.20
20	OCEANO SUB, Oceano	Distribution	115.00	12.00	7.20
21	OILFIELDS SUB, San Ardo	Distribution	60.00	12.00	
22	OLD KEARNEY SUB, Fresno	Distribution	70.00	12.00	13.20
23	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	2.40
24	OLD RIVER SUB, Knob Hill	Distribution		12.00	7.20
25	OLEMA SUB, Olema	Distribution	60.00	12.00	
26	OLETA SUB, Plymouth	Distribution	60.00	12.00	2.40
27	OLIVEHURST SUB, Olivehurst	Distribution	115.00	12.00	7.20
28	OREGON TRAIL SUB, Redding	Distribution	115.00	12.00	7.20
29	OREGON TRAIL SUB, Redding	Distribution	60.00	12.00	2.40
30	ORICK SUB, Orick	Distribution	60.00	12.00	2.40
31	ORLAND B SUB, Orland	Distribution	60.00	12.00	2.40
32	ORO FINO SUB, Magalia	Distribution	60.00	12.00	2.40
33	ORO LOMA SUB, Dos Palos	Transmission	115.00	70.00	13.20
34	ORO LOMA SUB, Dos Palos	Transmission	70.00	12.00	2.40
35	ORO LOMA SUB, Dos Palos	Transmission	115.00	12.00	
36	OROSI SUB, Orosi	Distribution	70.00	12.00	7.20
37	OROVILLE SUB, Oroville	Distribution	60.00	12.00	7.20
38	OROVILLE SUB, Oroville	Distribution	60.00	4.00	2.40
39	ORTIGA SUB, Los Banos	Distribution	70.00	12.00	2.40
40	OTTER SUB, Carmel	Distribution	60.00	12.00	

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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	PACIFICA SUB, Pacifica	Distribution	60.00	12.00	
2	PALERMO SUB, Palermo	Transmission	230.00	60.00	
3	PALERMO SUB, Palermo	Transmission	230.00	115.00	13.20
4	PALMER SUB, Sisquat	Distribution	115.00	12.00	7.20
5	PANAMA SUB, Bakersfield	Distribution	70.00	21.00	7.20
6	PANOCHE SUB, Mendota	Transmission	230.00	115.00	13.20
7	PANOCHE SUB, Mendota	Transmission	230.00	12.00	7.20
8	PANORAMA SUB, Anderson	Distribution	115.00	12.00	
9	PARADISE SUB, Paradise	Distribution	60.00	12.00	7.20
10	PARADISE SUB, Paradise	Distribution	115.00	12.00	
11	PARKWAY SUB, Vallejo	Distribution	230.00	12.00	7.20
12	PARLIER SUB, Parlier	Distribution	115.00	12.00	7.20
13	PASO ROBLES SUB, Paso Robles	Distribution	70.00	12.00	2.40
14	PAUL SWEET SUB, Santa Cruz	Distribution	115.00	21.00	7.20
15	PEABODY SUB, Fairfield	Distribution	230.00	21.00	7.20
16	PEACHTON SUB, Gridley	Distribution	60.00	12.00	2.40
17	PEASE SUB, Tierra Buena	Transmission	115.00	60.00	13.20
18	PEASE SUB, Tierra Buena	Transmission	115.00	12.00	
19	PENNGROVE SUB, Penngrove	Distribution	115.00	12.00	
20	PENRYN SUB, Penryn	Distribution	60.00	12.00	7.20
21	PEORIA SUB, Jamestown	Distribution	115.00	18.00	
22	PERRY SUB, Cambria	Distribution	70.00	12.00	2.40
23	PETALUMA A SUB, Petaluma	Distribution	60.00	4.00	2.40
24	PETALUMA C SUB, Petaluma	Distribution	60.00	12.00	
25	PHILO SUB, Philo	Distribution	60.00	12.00	2.40
26	PIERCY SUB, San Jose	Distribution	115.00	21.00	7.20
27	PIKE CITY SUB, Camptonville	Distribution	60.00	12.00	2.40
28	PINE GROVE SUB, Pine Grove	Distribution	60.00	12.00	2.40
29	PINEDALE SUB, FRESNO	Distribution	115.00	21.00	7.20
30	PITTSBURG PP SUB,	Transmission	230.00	115.00	13.20
31	PITTSBURG SUB, Pittsburg	Distribution	60.00	4.00	2.40
32	PLACER SUB, Auburn	Transmission	115.00	60.00	
33	PLACER SUB, Auburn	Transmission	115.00	12.00	
34	PLACERVILLE SUB, Placerville	Distribution	115.00	12.00	7.20
35	PLACERVILLE SUB, Placerville	Distribution	115.00	21.00	
36	PLAINFIELD SUB, Davis	Distribution	60.00	12.00	2.40
37	PLEASANT GROVE SUB, Pleasant Grove	Distribution	60.00	21.00	7.20
38	PLUMAS SUB, Wheatland	Distribution	60.00	21.00	7.20
39	PLUMAS SUB, Wheatland	Distribution	60.00	12.00	7.20
40	POINT ARENA SUB, Pt Arena	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	POINT MORETTI SUB, Davenport	Distribution	60.00	12.00	2.40
2	POINT PINOLE SUB, Richmond	Distribution	115.00	12.00	6.60
3	PORT COSTA BRICK SUB, Port Costa	Distribution	60.00	4.00	
4	POSO MOUNTAIN SUB, Kern	Distribution	115.00	21.00	
5	PRUNEDALE SUB, Prunedale	Distribution	115.00	12.00	7.20
6	PUEBLO SUB, Napa	Distribution	115.00	12.00	
7	PUEBLO SUB, Napa	Distribution	115.00	21.00	
8	PURISIMA SUB, Lompoc	Distribution	115.00	12.00	7.20
9	PUTAH CREEK SUB, Winters	Distribution	115.00	12.00	
10	RACE TRACK SUB, Jamestown	Distribution	115.00	17.00	
11	RADUM SUB, Pleasanton	Distribution	60.00	12.00	
12	RAINBOW SUB, Sanger	Distribution	115.00	12.00	7.20
13	RALSTON SUB, Belmont	Distribution	60.00	12.00	
14	RANCHERS COTTON SUB, Fresno	Distribution	115.00	12.00	7.20
15	RAVENSWOOD SUB, Menlo Park	Transmission	230.00	115.00	13.20
16	RAWSON SUB, Red Bluff	Distribution	60.00	12.00	2.40
17	RECLAMATION DIST#108 SUB, KNIGHTS LANDING	Distribution	60.00	2.00	
18	RECLAMATION DIST#1500 SUB, KNIGHTS LANDING	Distribution	60.00	2.00	
19	RECLAMATION DIST#2047 SUB, KNIGHTS LANDING	Distribution	60.00	2.00	
20	RED BLUFF SUB, Red Bluff	Distribution	60.00	12.00	2.40
21	REDBUD SUB, Clearlake Oaks	Distribution	115.00	12.00	7.20
22	REDWOOD CITY SUB, Redwood City	Distribution	60.00	12.00	7.20
23	REDWOOD CITY SUB, Redwood City	Distribution	60.00	4.00	
24	REEDLEY SUB, Reedley	Transmission	115.00	70.00	13.20
25	REEDLEY SUB, Reedley	Transmission	115.00	12.00	7.20
26	REEDLEY SUB, Reedley	Transmission	70.00	12.00	2.40
27	RENFRO SUB, BAKERSFIELD	Distribution	115.00	12.00	7.20
28	RESEARCH SUB, San Ramon	Distribution	230.00	21.00	7.20
29	RESERVATION ROAD SUB, Salinas	Distribution	60.00	12.00	2.40
30	RESERVE OIL SUB, Hanford	Distribution	70.00	12.00	2.40
31	RESERVE OIL SUB, Hanford	Distribution	70.00	4.00	
32	RICE SUB, Princeton	Distribution	60.00	12.00	4.16
33	RICHMOND R SUB, Richmond	Distribution	115.00	12.00	7.20
34	RIDGE CABIN SUB,	Distribution	60.00	12.00	
35	RINCON SUB, Santa Rosa	Distribution	115.00	12.00	
36	RIO BRAVO SUB, Shafter	Distribution	115.00	12.00	7.20
37	RIO DELL SUB, Rio Dell	Distribution	60.00	12.00	
38	RIO OSO SUB, Rio Oso	Transmission	230.00	115.00	13.20
39	RIPON SUB, Ripon	Distribution	115.00	17.00	
40	RISING RIVER SUB, Cassell,	Distribution	60.00	12.00	2.40

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1	RIVER OAKS SUB, San Jose	Distribution	115.00	21.00	7.20
2	RIVER ROCK SUB, Fresno	Distribution	70.00	12.00	2.40
3	RIVERBANK SUB, Escalon	Distribution	115.00	12.00	
4	ROB ROY SUB, Watsonville	Distribution	115.00	21.00	7.20
5	ROCKLIN SUB, Rocklin	Distribution	60.00	12.00	7.20
6	ROSEDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
7	ROSSMOOR SUB, Walnut Creek	Distribution	230.00	12.00	
8	ROUGH & READY ISLAND SUB, Stockton	Distribution	60.00	12.00	7.20
9	ROUND MOUNTAIN SUB, Rd Mtn	Transmission	500.00	230.00	13.80
10	RUSS RANCH SUB, Blue Lake	Distribution	60.00	12.00	
11	SALADO SUB, Patterson	Transmission	115.00	60.00	13.20
12	SALINAS SUB, Salinas	Transmission	115.00	60.00	13.20
13	SALINAS SUB, Salinas	Transmission	115.00	12.00	7.20
14	SALMON CREEK SUB, Bodega Bay	Distribution	60.00	12.00	2.40
15	SAN ANDREAS SUB, Millbrae	Distribution	60.00	34.60	
16	SAN ARDO SUB, San Ardo	Distribution	60.00	12.00	
17	SAN BENITO SUB, San Benito	Distribution	115.00	21.00	7.20
18	SAN BERNARD SUB, Lamont	Distribution	70.00	12.00	2.40
19	SAN BRUNO SUB, San Bruno	Distribution	60.00	4.00	
20	SAN CARLOS SUB, San Carlos	Distribution	60.00	12.00	7.20
21	SAN CARLOS SUB, San Carlos	Distribution	60.00	4.00	2.40
22	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	230.00	115.00	13.20
23	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	115.00	12.00	7.20
24	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	60.00	
25	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	230.00	115.00	
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 #3 SUB, Los Banos	Distribution	115.00	2.00	2.40
37	SAN LUIS #5 SUB, Los Banos	Distribution	115.00	2.00	2.40
38	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	70.00	13.20
39	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	12.00	7.20
40	SAN MATEO SUB, San Mateo	Transmission	115.00	60.00	

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1	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
2	SAN MATEO SUB, San Mateo	Transmission	115.00	21.00	
3	SAN MATEO SUB, San Mateo	Transmission	60.00	4.00	
4	SAN MIGUEL SUB, San Miguel	Distribution	70.00	12.00	7.20
5	SAN PABLO SUB, Richmond	Distribution	115.00	12.00	7.20
6	SAN RAFAEL SUB, San Rafael	Distribution	115.00	12.00	
7	SAN RAMON SUB, San Ramon	Transmission	230.00	60.00	13.20
8	SAN RAMON SUB, San Ramon	Transmission	230.00	21.00	12.00
9	SAND CREEK SUB, Orosi	Distribution	70.00	12.00	
10	SANGER SUB, Fresno	Transmission	115.00	70.00	6.60
11	SANGER SUB, Fresno	Transmission	115.00	12.00	7.20
12	SANTA MARIA SUB, Santa Maria	Distribution	115.00	12.00	7.20
13	SANTA NELLA SUB, Santa Nella	Distribution	70.00	12.00	2.40
14	SANTA RITA SUB, Dos Palos	Distribution	70.00	12.00	2.40
15	SANTA ROSA A SUB, Santa Rosa	Distribution	115.00	12.00	7.20
16	SANTA YNEZ SUB, Santa Maria	Distribution	115.00	12.00	7.20
17	SARATOGA SUB, Saratoga	Distribution	230.00	12.00	7.20
18	SAUSALITO SUB, Sausalito	Distribution	60.00	12.00	2.40
19	SAUSALITO SUB, Sausalito	Distribution	60.00	4.00	
20	SCHINDLER SUB, Five Points	Transmission	115.00	70.00	13.20
21	SCHINDLER SUB, Five Points	Transmission	115.00	12.00	7.20
22	SEMITROPIC SUB, Wasco	Transmission	115.00	70.00	13.80
23	SEMITROPIC SUB, Wasco	Transmission	115.00	12.00	7.20
24	SERRAMONTE SUB, Daly City	Distribution	115.00	12.00	
25	SHADY GLEN SUB, Colfax	Distribution	60.00	12.00	2.40
26	SHAFTER SUB, Shafter	Distribution	115.00	12.00	7.20
27	SHARON SUB, Chowchilla	Distribution	115.00	12.00	
28	SHEPARD SUB, Clovis	Distribution	115.00	21.00	7.20
29	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	21.00	7.20
30	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	12.00	7.20
31	SHREDDER SUB, Redwood City	Distribution	115.00	4.00	6.60
32	SILVERADO SUB, St. Helena	Distribution	115.00	21.00	
33	SISQUOC SUB, Orcutt	Distribution	115.00	12.00	7.20
34	SKAGGS ISLAND SUB, Skaggs Island	Distribution	115.00	12.00	2.40
35	SMARTVILLE SUB, Smartville	Distribution	60.00	12.00	
36	SMYRNA SUB, Wasco	Distribution	115.00	12.00	7.20
37	SNEATH LANE SUB, San Bruno	Distribution	60.00	12.00	2.40
38	SOBRANTE SUB, Orinda	Transmission	230.00	115.00	
39	SOBRANTE SUB, Orinda	Transmission	115.00	12.00	7.20
40	SOLEDAD SUB, Soledad	Transmission	115.00	60.00	

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1	SOLEDAD SUB, Soledad	Transmission	60.00	12.00	
2	SONOMA A SUB, Sonoma	Distribution	115.00	12.00	
3	SOUTH BAY #1 & #2 SUB, Tracy	Distribution	60.00	4.00	
4	SPANISH CREEK SUB,	Distribution	60.00	44.00	
5	SPENCE SUB, Salinas	Distribution	60.00	12.00	
6	SRI SUB, Menlo Park	Distribution	60.00	12.00	
7	STAFFORD SUB, Novato	Distribution	60.00	12.00	
8	STAGG SUB, Stockton	Transmission	230.00	60.00	13.20
9	STAGG SUB, Stockton	Transmission	230.00	21.00	7.20
10	STAGG SUB, Stockton	Transmission	60.00	12.00	2.40
11	STAUFFER SUB, Martinez	Distribution	60.00	4.00	
12	STELLING SUB, Cupertino	Distribution	115.00	12.00	7.20
13	STILLWATER STA SUB, Project City	Distribution	60.00	12.00	2.40
14	STOCKDALE SUB, Bakersfield	Distribution	230.00	21.00	7.20
15	STOCKDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
16	STOCKTON A SUB, Stockton	Distribution	115.00	12.00	
17	STOCKTON A SUB, Stockton	Distribution	60.00	4.00	
18	STOCKTON ACRES SUB, Stockton	Distribution	60.00	4.00	
19	STONE CORRAL SUB, Woodlake	Distribution	70.00	12.00	2.40
20	STONE SUB, San Jose	Distribution	115.00	12.00	7.20
21	STOREY SUB, Madera	Distribution	230.00	12.00	7.20
22	STROUD SUB, Helm	Distribution	70.00	12.00	2.40
23	SUISUN SUB, Fairfield	Distribution	115.00	12.00	7.20
24	SUMMIT SUB, Soda Springs	Distribution	60.00	12.00	2.40
25	SUNOL SUB, Sunol	Distribution	60.00	12.00	7.20
26	SWIFT SUB, San Jose	Distribution	115.00	21.00	7.20
27	SYCAMORE CREEK SUB, Chico	Distribution	115.00	12.00	
28	TABLE MOUNTAIN SUB, Oroville	Transmission	230.00	115.00	
29	TABLE MOUNTAIN SUB, Oroville	Transmission	500.00	230.00	13.80
30	TAFT SUB, Taft	Transmission	115.00	70.00	13.20
31	TAFT SUB, Taft	Transmission	115.00	12.00	7.20
32	TAMARACK SUB, Soda Springs	Distribution	60.00	12.00	7.20
33	TASSAJARA SUB, Danville	Distribution	230.00	21.00	7.20
34	TECUYA SUB, Bakersfield	Distribution	70.00	2.00	2.40
35	TEJON SUB, Leboc	Distribution	70.00	12.00	2.40
36	TEMBLOR SUB, McKittrick	Distribution	115.00	12.00	2.40
37	TEMPLETON SUB, TEMPLETON	Transmission	230.00	70.00	13.20
38	TEMPLETON SUB, TEMPLETON	Transmission	230.00	21.00	7.20
39	TERMINOUS SUB, Lodi	Distribution	60.00	12.00	
40	TESLA SUB, Tracy	Transmission	230.00	115.00	13.20

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1	TESLA SUB, Tracy	Transmission	500.00	230.00	13.20
2	TEVIS SUB, Oildale	Distribution	115.00	21.00	7.20
3	TIDEWATER SUB, Martinez	Distribution	230.00	21.00	
4	TIVY VALLEY SUB, Fresno	Distribution	70.00	12.00	7.20
5	TOCALOMA SUB, Tocaloma	Distribution	60.00	4.00	
6	TRACY SUB, Tracy	Distribution	115.00	12.00	7.20
7	TRES VIAS SUB, Oroville	Distribution	60.00	12.00	7.20
8	TRIMBLE SUB, San Jose	Distribution	115.00	12.00	7.20
9	TRIMBLE SUB, San Jose	Distribution	115.00	21.00	7.20
10	TRINIDAD SUB, Trinidad	Distribution	60.00	12.00	2.40
11	TRINITY SUB, Weaverville	Transmission	115.00	60.00	13.20
12	TUDOR SUB, Tudor	Distribution	60.00	12.00	
13	TULARE LAKE SUB, Kettleman	Distribution	70.00	12.00	2.40
14	TULUCAY SUB, Napa	Transmission	230.00	60.00	13.20
15	TULUCAY SUB, Napa	Transmission	60.00	12.00	7.20
16	TUPMAN SUB, Tupman	Distribution	115.00	12.00	7.20
17	TWISSELMAN SUB, Blackwell Corners	Distribution	70.00	12.00	7.20
18	TYLER SUB, Red Bluff	Distribution	60.00	12.00	2.40
19	UKIAH SUB, Ukiah	Distribution	115.00	12.00	7.20
20	UPPER LAKE SUB, Upper Lake	Distribution	60.00	12.00	2.40
21	URICH SUB, Martinez	Distribution	60.00	4.00	
22	VACA DIXON SUB, Vacaville	Transmission	115.00	60.00	13.20
23	VACA DIXON SUB, Vacaville	Transmission	230.00	115.00	13.20
24	VACA DIXON SUB, Vacaville	Transmission	500.00	230.00	13.80
25	VACA DIXON SUB, Vacaville	Transmission	115.00	12.00	7.20
26	VACAVILLE SUB, Vacaville	Distribution	115.00	12.00	7.20
27	VALLECITOS SUB, Sunol	Distribution	60.00	12.00	
28	VALLEY HOME SUB, Valley Home	Distribution	60.00	17.00	
29	VALLEY HOME SUB, Valley Home	Distribution	115.00	17.00	
30	VALLEY SPRINGS SUB, Valley Springs	Transmission	230.00	60.00	13.20
31	VALLEY VIEW SUB, El Sobrante	Distribution	115.00	12.00	
32	VASCO SUB, Livermore	Distribution	60.00	12.00	
33	VASONA SUB, Los Gatos	Distribution	230.00	12.00	7.20
34	VICTOR SUB, Lodi	Distribution	60.00	12.00	2.40
35	VIEJO SUB, Monterey	Distribution	60.00	21.00	7.20
36	VIERRA SUB, Lathrop	Distribution	115.00	17.00	7.20
37	VINA SUB, Vina	Distribution	60.00	12.00	2.40
38	VINEYARD SUB, Pleasanton	Distribution	230.00	21.00	7.20
39	VOLTA #1PH SUB, Shingletown	Distribution	60.00	12.00	2.40
40	WAHTOKE SUB, Reedley	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	03/09/2018	End of 2017/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WASCO SUB, Wasco	Distribution	70.00	12.00	2.40
2	WATERLOO SUB, Stockton	Distribution	60.00	12.00	2.40
3	WATERSHED SUB, Redwood City	Distribution	60.00	4.00	
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	230.00	60.00	13.20
7	WEBER SUB, Stockton	Transmission	60.00	12.00	7.20
8	WEBER SUB, Stockton	Transmission	230.00	12.00	7.20
9	WEEDPATCH SUB, Weedpatch	Distribution	70.00	12.00	7.20
10	WEIMAR SUB, Weimar	Distribution	60.00	12.00	2.40
11	WELLFIELD SUB, Lamont	Distribution	70.00	12.00	2.40
12	WEST FRESNO SUB, Fresno	Distribution	115.00	12.00	7.20
13	WEST LANE SUB, Stockton	Distribution	60.00	12.00	7.20
14	WEST SACRAMENTO SUB, WEST SACRAMENTO	Distribution	115.00	12.00	7.20
15	WEST SIDE SUB, Tracy	Distribution	60.00	2.00	
16	WESTLANDS SUB, San Joaquin	Distribution	70.00	4.00	
17	WESTLEY SUB, Westley	Distribution	60.00	12.00	2.40
18	WESTPARK SUB, Bakersfield	Distribution	115.00	12.00	7.20
19	WHEATLAND SUB, Wheatland	Distribution	60.00	12.00	7.20
20	WHEELER RIDGE SUB, Bakersfield	Transmission	115.00	70.00	13.20
21	WHEELER RIDGE SUB, Bakersfield	Transmission	230.00	70.00	13.20
22	WHEELER RIDGE SUB, Bakersfield	Transmission	70.00	12.00	2.40
23	WHISMAN SUB, Mt. View	Distribution	115.00	12.00	7.20
24	WHITMORE SUB, Whitmore	Distribution	60.00	12.00	2.40
25	WILDWOOD SUB, Wildwood	Distribution	115.00	12.00	
26	WILKINS SLOUGH SUB, Arbuckle	Distribution	60.00	12.00	2.40
27	WILLIAMS SUB, Williams	Distribution	60.00	12.00	7.20
28	WILLITS A SUB, Willits	Distribution	60.00	12.00	2.40
29	WILLOW CREEK SUB, Willow Creek	Distribution	60.00	12.00	2.40
30	WILLOW PASS SUB, Pittsburg	Distribution	115.00	21.00	7.20
31	WILLOW PASS SUB, Pittsburg	Distribution	60.00	12.00	2.40
32	WILLOWS A SUB, Willows	Distribution	60.00	12.00	
33	WILSON SUB, Merced	Transmission	230.00	115.00	13.20
34	WILSON SUB, Merced	Transmission	115.00	12.00	
35	WINTERS SUB, Winters	Distribution	60.00	12.00	
36	WOLFE SUB, Cupertino	Distribution	115.00	12.00	
37	WOODACRE SUB, Woodacre	Distribution	60.00	12.00	
38	WOODCHUCK SUB, Wilson Village	Distribution	70.00	21.00	
39	WOODLAND SUB, Woodland	Distribution	115.00	12.00	7.20
40	WOODSIDE SUB, Woodside	Distribution	60.00	12.00	

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	03/09/2018	End of 2017/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WOODWARD SUB, Fresno	Distribution	115.00	21.00	7.20
2	WRIGHT SUB, Los Banos	Distribution	70.00	12.00	2.40
3	WYANDOTTE SUB, Oroville	Distribution	115.00	12.00	7.20
4	YOSEMITE PARK SUB,	Distribution	70.00	12.00	7.20
5	ZACA SUB, Santa Maria	Distribution	115.00	12.00	7.20
6	ZAMORA SUB, Zamora	Distribution	115.00	12.00	
7	Rounding issues in column f				
8	Total Distribution and Transmission Substations		91065.00	20084.90	4300.12
9	Transmission only Substations		24120.00	10990.00	1342.20
10					
11	Combined Dist Subs < 10MVA (130 substations)				
12					
13					
14					
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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
90	2		2.00000			2
27	2		2.00000			3
13	1		1.00000			4
60	2		2.00000			5
41	2		2.00000			6
1	1		1.00000			7
49	4	1	2.00000			8
30	1		1.00000			9
19	3	1	1.00000			10
16	1		1.00000			11
38	2		2.00000			12
2	3		1.00000			13
16	1		1.00000			14
11	3	1	1.00000			15
16	1		1.00000			16
16	1		1.00000			17
27	4	1	2.00000			18
60	2		2.00000			19
360	6	1	2.00000			20
13	3	1	1.00000			21
210	3		3.00000			22
30	1		1.00000			23
334	4	1	2.00000			24
840	2		2.00000			25
90	2		2.00000			26
25	2		2.00000			27
9	3	1	1.00000			28
16	3	1	1.00000			29
16	1		1.00000			30
112	2		2.00000			31
80	3		1.00000			32
45	1		1.00000			33
225	3		3.00000			34
7	1		1.00000			35
13	1		1.00000			36
9	3	1	1.00000			37
6	3		1.00000			38
120	3		3.00000			39
39	4		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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment	Number of Units	Total Capacity (In MVa)	Line No.
(f)	(g)	(h)	(i)	(j)	(k)	
5	3		1.00000			1
90	2		2.00000			2
75	2		2.00000			3
16	1		1.00000			4
13	1		1.00000			5
57	2		2.00000			6
57	3		3.00000			7
16	6	1	2.00000			8
70	3		3.00000			9
400	2		Sync Cond	1	40	10
9	1		1.00000			11
5	1		1.00000			12
135	3		3.00000			13
9	2		2.00000			14
16	2		2.00000			15
5	1		1.00000			16
11	3	1	1.00000			17
3	6		1.00000			18
15	3		1.00000			19
6	6	1	1.00000			20
20	3		1.00000			21
13	1		1.00000			22
13	3	1	1.00000			23
1	3		1.00000			24
90	2		2.00000			25
13	1		1.00000			26
16	1		1.00000			27
2	3	1	1.00000			28
400	2		2.00000			29
30	1		1.00000			30
6	3	1	1.00000			31
9	3		1.00000			32
30	1		1.00000			33
225	3		3.00000			34
90	3	1	1.00000			35
6	3	1	1.00000			36
840	2		2.00000			37
120	3		3.00000			38
3	3		1.00000			39
90	3		3.00000			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.
21	2		2.00000			1
76	3		3.00000			2
90	2		2.00000			3
45	1		1.00000			4
30	1		1.00000			5
7	6	1	2.00000			6
90	3	1	1.00000			7
46	2		2.00000			8
11	1		1.00000			9
20	3		1.00000			10
30	1		1.00000			11
15	3		1.00000			12
19	3		1.00000			13
135	3		3.00000			14
21	3	1	1.00000			15
16	1		1.00000			16
5	3	1	1.00000			17
41	2		2.00000			18
90	2		2.00000			19
11	1		1.00000			20
6	3	1	1.00000			21
60	2		2.00000			22
24	1		1.00000			23
11	6		1.00000			24
37	3		2.00000			25
3	3		1.00000			26
16	1		1.00000			27
16	1		1.00000			28
14	2		2.00000			29
25	2		2.00000			30
2	1		1.00000			31
50	4		2.00000			32
76	3		1.00000			33
45	1		1.00000			34
90	2		2.00000			35
30	3	1	1.00000			36
39	4	1	2.00000			37
11	1		1.00000			38
5	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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	2		2.00000			1
6	3	1	1.00000			2
9	3		1.00000			3
3	3	1	1.00000			4
13	1		1.00000			5
41	2		2.00000			6
19	3	1	1.00000			7
16	1		1.00000			8
8	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
90	3	1	1.00000			15
11	3	1	1.00000			16
135	3		3.00000			17
29	2		2.00000			18
135	3		3.00000			19
16	1		1.00000			20
20	6	1	2.00000			21
19	3	1	1.00000			22
90	2		2.00000			23
45	1		1.00000			24
27	2		2.00000			25
21	3		1.00000			26
61	2		2.00000			27
214	6	1	2.00000			28
6	3		1.00000			29
3	3	1	1.00000			30
59	3		3.00000			31
12	1		1.00000			32
21	6	1	2.00000			33
120	6	2	2.00000			34
180	3	1	1.00000			35
225	3		3.00000			36
42	3	1	1.00000			37
290	4	1	2.00000			38
20	3	1	1.00000			39
28	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.
90	3	1	1.00000			1
46	2		2.00000			2
45	1		1.00000			3
13	3	2	1.00000			4
58	10	3	2.00000			5
30	1		1.00000			6
43	2		2.00000			7
200	1		1.00000			8
588	4	2	2.00000			9
7	1		1.00000			10
29	6	1	2.00000			11
85	2		2.00000			12
400	2		2.00000			13
240	6	1	2.00000			14
75	2		2.00000			15
35	3		3.00000			16
7	1		1.00000			17
6	3	1	1.00000			18
30	1		1.00000			19
5	3		1.00000			20
5	1		1.00000			21
6	3		1.00000			22
90	2		2.00000			23
19	3	1	1.00000			24
16	3		1.00000			25
16	1		1.00000			26
60	2		2.00000			27
6	3		1.00000			28
135	3		3.00000			29
135	3		3.00000			30
90	2		2.00000			31
75	2		2.00000			32
16	1		1.00000			33
400	2		2.00000			34
75	2		2.00000			35
14	1		1.00000			36
43	2		2.00000			37
5	1		1.00000			38
61	2		2.00000			39
60	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.
170	6	1	2.00000			1
11	3	1	1.00000			2
30	1		1.00000			3
135	3	1	3.00000			4
75	2		2.00000			5
3	6	1	1.00000			6
11	1		1.00000			7
13	1		1.00000			8
2	3		1.00000			9
105	3		3.00000			10
32	6	1	2.00000			11
4	3	1	1.00000			12
9	6		1.00000			13
68	3	1	1.00000			14
180	4		4.00000			15
25	2	1	2.00000			16
400	2		2.00000			17
16	1		1.00000			18
6	3	1	1.00000			19
16	1		1.00000			20
8	1		1.00000			21
840	2		2.00000			22
135	3		3.00000			23
45	1		1.00000			24
90	2		2.00000			25
25	4		2.00000			26
90	2		2.00000			27
63	2		2.00000			28
45	1		1.00000			29
127	3		3.00000			30
32	2		2.00000			31
180	4		4.00000			32
23	2		2.00000			33
11	1		1.00000			34
3	3	1	1.00000			35
13	1		1.00000			36
11	3	1	1.00000			37
7	1		1.00000			38
2	3	1	1.00000			39
6	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.
9	3	1	1.00000			1
13	1		1.00000			2
21	3	1	1.00000			3
80	3	1	1.00000			4
90	2	1	2.00000			5
13	1		1.00000			6
50	3		1.00000			7
60	2		2.00000			8
30	1		1.00000			9
60	2		2.00000			10
225	3		3.00000			11
30	1		1.00000			12
22	2		2.00000			13
25	3		1.00000			14
50	2		2.00000			15
11	1		1.00000			16
21	3	1	1.00000			17
60	2		2.00000			18
45	1		1.00000			19
19	3	1	1.00000			20
2	3	1	1.00000			21
6	3	1	1.00000			22
60	2		2.00000			23
105	3		3.00000			24
32	2		2.00000			25
2	3	1	1.00000			26
25	4		2.00000			27
5	3		1.00000			28
49	4	1	2.00000			29
600	2		2.00000			30
823	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
2	3	1	1.00000			38
5	1		1.00000			39
117	3	1	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) 03/09/2018	Year/Period of Report End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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.
120	3		1.00000			1
1122	3	1	2.00000			2
45	1		1.00000			3
19	3		1.00000			4
9	3		1.00000			5
22	4		2.00000			6
19	3		1.00000			7
16	1		1.00000			8
255	4	1	2.00000			9
30	1		1.00000			10
32	2		2.00000			11
7	1		1.00000			12
80	3		1.00000			13
840	2		2.00000			14
16	1		1.00000			15
22	2		2.00000			16
27	2		2.00000			17
81	3		3.00000			18
90	2		2.00000			19
19	3	1	1.00000			20
2	3	1	1.00000			21
38	3		1.00000			22
60	2		2.00000			23
32	2		2.00000			24
12	7	1	2.00000			25
60	2		2.00000			26
21	3		3.00000			27
50	5		3.00000			28
8	6	1	1.00000			29
67	5		3.00000			30
16	1		1.00000			31
13	2		2.00000			32
12	1		1.00000			33
2	3		1.00000			34
29	2		2.00000			35
60	2		2.00000			36
19	2		2.00000			37
16	3		1.00000			38
134	3		1.00000			39
308	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.
180	3	1	1.00000			1
46	2		2.00000			2
50	3	1	1.00000			3
13	1		1.00000			4
1260	3		Sync Cond	2	80	5
150	2		2.00000			6
90	2		2.00000			7
77	3		3.00000			8
60	2		2.00000			9
90	2		2.00000			10
9	3	1	1.00000			11
70	2		2.00000			12
25	1		1.00000			13
16	1		1.00000			14
9	3		1.00000			15
40	1		1.00000			16
13	3	1	1.00000			17
90	2		2.00000			18
16	1		1.00000			19
133	6		2.00000			20
77	3		2.00000			21
11	1		1.00000			22
4	1		1.00000			23
4	1		1.00000			24
400	2		SVC	1	50	25
20	3		1.00000			26
400	2		2.00000			27
823	4	1	2.00000			28
46	2		2.00000			29
16	1		1.00000			30
3	3		1.00000			31
9	3	1	1.00000			32
13	1		1.00000			33
5	3	1	1.00000			34
5	1		1.00000			35
16	1		1.00000			36
29	2		2.00000			37
90	2		2.00000			38
39	2		2.00000			39
105	3		3.00000			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.
400	2		2.00000			1
22	1		1.00000			2
27	2		2.00000			3
3	1		1.00000			4
76	3		1.00000			5
30	1		1.00000			6
60	2		2.00000			7
135	3		3.00000			8
90	2		2.00000			9
400	2		2.00000			10
1260	3		3.00000			11
5	1		1.00000			12
11	3	1	1.00000			13
11	3		1.00000			14
47	3		3.00000			15
90	3	1	1.00000			16
90	2		2.00000			17
135	3		3.00000			18
9	1		1.00000			19
23	2		2.00000			20
6	3		1.00000			21
49	4		2.00000			22
400	2		2.00000			23
840	2		2.00000			24
75	2		2.00000			25
215	4		4.00000			26
25	3	1	1.00000			27
90	2		2.00000			28
75	2		2.00000			29
76	3		3.00000			30
30	1		1.00000			31
90	3		1.00000			32
165	3		3.00000			33
14	2		2.00000			34
7	3	1	1.00000			35
145	5	1	3.00000			36
8	6	1	1.00000			37
45	1		1.00000			38
7	1		1.00000			39
75	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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
90	2		2.00000			1
1	3	1	1.00000			2
91	3		3.00000			3
19	3		1.00000			4
27	2		2.00000			5
25	6		2.00000			6
45	1		1.00000			7
11	3		1.00000			8
100	3		3.00000			9
400	2		2.00000			10
30	1	1	1.00000			11
90	2		2.00000			12
46	2		2.00000			13
21	3	1	1.00000			14
5	3	1	1.00000			15
45	1		1.00000			16
45	1		1.00000			17
51	3		3.00000			18
334	4		2.00000			19
840	3	1	1.00000			20
13	3	1	1.00000			21
840	2		2.00000			22
32	2		2.00000			23
13	3	1	1.00000			24
43	2		2.00000			25
4	1		1.00000			26
4	1		1.00000			27
21	3	1	1.00000			28
5	3	1	1.00000			29
29	2		2.00000			30
19	3		1.00000			31
45	1		1.00000			32
71	7		3.00000			33
30	1		1.00000			34
21	2		2.00000			35
45	1		1.00000			36
45	1		1.00000			37
3	3		1.00000			38
105	3		3.00000			39
135	3		3.00000			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.
100	1	1	2.00000			1
135	8	1	4.00000			2
5	1		1.00000			3
2	3	1	1.00000			4
11	3		1.00000			5
32	2		2.00000			6
6	3		1.00000			7
13	3	1	1.00000			8
49	4	1	2.00000			9
43	4	1	2.00000			10
11	3	1	1.00000			11
1243	5	1	Sync Cond	2	80	12
90	2		2.00000			13
21	2		2.00000			14
32	2		2.00000			15
105	3		3.00000			16
13	4	1	1.00000			17
45	1		1.00000			18
170	3		3.00000			19
280	4	1	2.00000			20
5	3	1	1.00000			21
90	3	1	1.00000			22
30	1		1.00000			23
32	2		2.00000			24
18	2		2.00000			25
50	3		1.00000			26
45	1		1.00000			27
45	1		1.00000			28
5	3		1.00000			29
21	3	1	1.00000			30
840	2		2.00000			31
45	1		1.00000			32
3366	9	2	3.00000			33
1630	10	1	4.00000			34
11	1		1.00000			35
6	3	1	1.00000			36
34	4	1	2.00000			37
1260	3		3.00000			38
3364	9	2	3.00000			39
23	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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
90	3		1.00000			1
60	2		2.00000			2
6	3	1	1.00000			3
90	2		2.00000			4
75	2		2.00000			5
11	1		1.00000			6
14	3	1	1.00000			7
43	2		2.00000			8
7	1		1.00000			9
90	2		2.00000			10
45	1		1.00000			11
200	1		1.00000			12
134	3	1	1.00000			13
1260	3		1.00000			14
135	3		3.00000			15
29	2		2.00000			16
11	3	1	1.00000			17
7	2		2.00000			18
1243	5	1	3.00000			19
45	1		1.00000			20
120	3		3.00000			21
30	1		1.00000			22
269	3	1	1.00000			23
16	1		1.00000			24
105	3		3.00000			25
1680	4		2.00000			26
1122	3	1	1.00000			27
115	3		2.00000			28
135	3		2.00000			29
16	1		1.00000			30
79	5		3.00000			31
30	1		1.00000			32
2	3		1.00000			33
3	3		1.00000			34
5	3		1.00000			35
200	4	1	1.00000			36
150	2		2.00000			37
80	3		1.00000			38
1646	8	1	SVC	1	220	39
90	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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	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)	
20	4	1	2.00000			1
29	2		2.00000			2
41	4		2.00000			3
16	1		1.00000			4
32	2		2.00000			5
90	2		2.00000			6
6	6		1.00000			7
45	1		1.00000			8
90	2		2.00000			9
45	1		1.00000			10
23	2		2.00000			11
4	1		1.00000			12
43	3		2.00000			13
210	4		4.00000			14
175	4		4.00000			15
120	3		3.00000			16
38	3	1	1.00000			17
135	3		3.00000			18
90	3		3.00000			19
75	2		2.00000			20
42	6	1	2.00000			21
31	4		2.00000			22
16	1		1.00000			23
45	1		1.00000			24
6	3	2	2.00000			25
18	4		2.00000			26
60	2		2.00000			27
16	1		1.00000			28
6	3		1.00000			29
5	3	1	1.00000			30
25	7		2.00000			31
11	1		1.00000			32
60	3		1.00000			33
22	3		1.00000			34
45	1		1.00000			35
41	2		2.00000			36
25	2		2.00000			37
5	3	1	1.00000			38
16	1		1.00000			39
9	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)	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)	
23	2		2.00000			1
168	3	1	1.00000			2
420	1		1.00000			3
11	1		1.00000			4
45	1		1.00000			5
840	2		2.00000			6
30	1		1.00000			7
30	1		1.00000			8
45	1		1.00000			9
45	1		1.00000			10
30	1		1.00000			11
45	1		1.00000			12
90	3		3.00000			13
135	3		3.00000			14
195	3		3.00000			15
14	6	1	2.00000			16
80	3	1	1.00000			17
50	2		2.00000			18
13	1		1.00000			19
61	2		2.00000			20
58	4		2.00000			21
5	1		1.00000			22
3	3	1	1.00000			23
57	5	1	3.00000			24
5	3		1.00000			25
45	1		1.00000			26
6	3	1	1.00000			27
22	4		2.00000			28
135	3		3.00000			29
840	2		2.00000			30
6	3	1	1.00000			31
95	3		1.00000			32
41	4	1	2.00000			33
30	1		1.00000			34
30	1		1.00000			35
39	2		2.00000			36
135	3		3.00000			37
45	1		1.00000			38
13	1		1.00000			39
2	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.
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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.
11	1		1.00000			1
16	1		1.00000			2
3	3		1.00000			3
65	2		1.00000			4
32	2		2.00000			5
45	1		StatCom	2	8	6
45	1		1.00000			7
11	1		1.00000			8
32	2		2.00000			9
16	1		1.00000			10
25	6		2.00000			11
30	1		1.00000			12
16	4		2.00000			13
16	1		1.00000			14
823	4	1	2.00000			15
19	3		1.00000			16
3	3	1	1.00000			17
8	3	1	1.00000			18
3	3		1.00000			19
50	5		3.00000			20
23	3		2.00000			21
70	5		3.00000			22
14	3		1.00000			23
190	4	1	2.00000			24
30	1		1.00000			25
30	1		1.00000			26
90	2		2.00000			27
45	1		1.00000			28
11	1		1.00000			29
4	1		1.00000			30
3	1		1.00000			31
14	2		2.00000			32
90	2		2.00000			33
	1		1.00000			34
32	2		2.00000			35
64	4		2.00000			36
11	3		1.00000			37
254	6		2.00000			38
73	2		2.00000			39
11	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.
90	2		2.00000			1
6	1		1.00000			2
73	4	1	2.00000			3
23	1		1.00000			4
27	4	1	2.00000			5
30	1		1.00000			6
90	2		2.00000			7
16	1		1.00000			8
1122	3	1	1.00000			9
1	1		1.00000			10
200	2		2.00000			11
400	2		2.00000			12
90	2		2.00000			13
11	3	1	1.00000			14
9	1		1.00000			15
11	3	1	1.00000			16
30	1		1.00000			17
19	3		1.00000			18
6	3	1	1.00000			19
29	2		2.00000			20
12	3	1	1.00000			21
420	1		1.00000			22
186	3		3.00000			23
100	1		1.00000			24
823	4	1	2.00000			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
5	1		1.00000			36
5	1		1.00000			37
200	1		1.00000			38
135	3		3.00000			39
200	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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1260	3		Sync Cond	2	88	1
45	1		1.00000			2
13	3	1	1.00000			3
16	1		1.00000			4
45	1		1.00000			5
120	3		3.00000			6
90	3	1	1.00000			7
300	4		4.00000			8
8	3	1	1.00000			9
30	3	1	1.00000			10
60	2		2.00000			11
90	2		2.00000			12
27	2		2.00000			13
12	3		1.00000			14
135	3		3.00000			15
41	2		2.00000			16
157	3		3.00000			17
21	3	1	1.00000			18
5	3	1	1.00000			19
90	3	1	1.00000			20
60	2		2.00000			21
90	3	1	1.00000			22
30	1		1.00000			23
13	1		1.00000			24
9	3	1	1.00000			25
72	4	1	2.00000			26
11	1		1.00000			27
45	1		1.00000			28
61	2		2.00000			29
16	1		1.00000			30
15	3	1	1.00000			31
60	2		2.00000			32
32	2		2.00000			33
4	1		1.00000			34
3	3	1	1.00000			35
49	4		2.00000			36
19	6		2.00000			37
823	4	1	2.00000			38
30	1		1.00000			39
75	6		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.
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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)	
11	1		1.00000			1
60	2		2.00000			2
25	3		3.00000			3
19	1		1.00000			4
13	3	1	2.00000			5
13	1		1.00000			6
25	2		2.00000			7
600	2		2.00000			8
150	2		2.00000			9
51	4	1	2.00000			10
5	1		1.00000			11
105	3		2.00000			12
11	3	1	1.00000			13
225	3		3.00000			14
75	2		2.00000			15
105	3		3.00000			16
22	6		1.00000			17
4	1		1.00000			18
17	2		2.00000			19
45	1		1.00000			20
90	2		2.00000			21
21	3	1	1.00000			22
120	3		3.00000			23
9	3	1	1.00000			24
13	1		1.00000			25
135	3		3.00000			26
90	3		3.00000			27
1008	5	1	3.00000			28
1122	3	1	1.00000			29
162	4		2.00000			30
27	2		2.00000			31
13	1		1.00000			32
225	3		3.00000			33
5	1		1.00000			34
49	4		2.00000			35
21	3	1	1.00000			36
175	1		1.00000			37
90	2		2.00000			38
5	3		1.00000			39
806	6	1	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.
3366	9	2	3.00000			1
90	2		2.00000			2
150	2		2.00000			3
13	1		1.00000			4
2	3	1	1.00000			5
121	4		4.00000			6
16	1		1.00000			7
90	2		2.00000			8
90	2		2.00000			9
10	3	1	1.00000			10
90	3	1	1.00000			11
5	1		1.00000			12
24	4	2	2.00000			13
400	2		2.00000			14
30	1		1.00000			15
61	2		2.00000			16
32	2		2.00000			17
19	6		2.00000			18
29	2		2.00000			19
3	3		1.00000			20
10	3	1	1.00000			21
290	4	1	2.00000			22
1094	8		3.00000			23
2244	6	1	2.00000			24
105	3		3.00000			25
120	3		3.00000			26
5	1		1.00000			27
6	3	1	1.00000			28
30	1		1.00000			29
334	4	1	2.00000			30
29	2		2.00000			31
17	6		2.00000			32
90	2		4.00000			33
30	1		1.00000			34
60	2		2.00000			35
90	2		2.00000			36
3	3	1	1.00000			37
150	2	1	2.00000			38
21	3	1	1.00000			39
60	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)	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)	
20	3		1.00000			1
11	1		1.00000			2
2	3		1.00000			3
16	1		1.00000			4
8	1		1.00000			5
600	2		2.00000			6
50	2		2.00000			7
90	2		2.00000			8
30	1		1.00000			9
9	3	1	1.00000			10
24	4		2.00000			11
135	3		3.00000			12
30	1		1.00000			13
105	3		3.00000			14
4	3		1.00000			15
4	1		1.00000			16
29	2		2.00000			17
105	3		3.00000			18
44	4	1	2.00000			19
60	3	1	1.00000			20
400	2		2.00000			21
19	3		1.00000			22
105	3		3.00000			23
6	3	1	1.00000			24
3	1	1	2.00000			25
9	3	1	1.00000			26
27	2		2.00000			27
19	3	1	1.00000			28
13	3	1	1.00000			29
30	1		1.00000			30
11	3	1	1.00000			31
14	3	1	1.00000			32
689	4	1	2.00000			33
14	1		1.00000			34
8	6	1	1.00000			35
120	3		3.00000			36
9	3	1	1.00000			37
23	3		1.00000			38
135	3		3.00000			39
60	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	03/09/2018	End of 2017/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
135	3		3.00000			1
13	1		1.00000			2
120	3		3.00000			3
5	1	1	1.00000			4
11	1		1.00000			5
27	2		2.00000			6
-70						7
96564	2122	216		12	581	8
64723	398	63				9
						10
683	337	55				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

Schedule Page: 426 Line No.: 40 Column: e

2.4 and 7.2

Schedule Page: 426.1 Line No.: 7 Column: e

2.4 and 7.2

Schedule Page: 426.2 Line No.: 18 Column: e

2.4 and 7.2

Schedule Page: 426.3 Line No.: 18 Column: e

2.4 and 7.2

Schedule Page: 426.7 Line No.: 28 Column: e

2.4 and 7.2

Schedule Page: 426.8 Line No.: 37 Column: e

2.4 and 7.2

Schedule Page: 426.9 Line No.: 22 Column: e

2.4 and 7.2

Schedule Page: 426.14 Line No.: 13 Column: e

2.4 and 7.2

Schedule Page: 426.14 Line No.: 36 Column: e

2.4 and 7.2

Schedule Page: 426.18 Line No.: 35 Column: e

2.4 and 7.2

Schedule Page: 426.21 Line No.: 7 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: 426.21 Line No.: 9 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)

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2		PG&E Corporation		
3	Corporate A&G Allocations		923, 426.4, 426.5	65,367,933
4	Total - Administrative & General Expenses			65,367,933
5				
6	Rent Expense	Eureka Energy Company	532.0	321,288
7				
8	Total Non-power Good/Srv. provided by Affiliates			65,689,221
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			817,783
23	ADMINISTRATION			566,201
24	BANKING SERVICES			34,587
25	BUSINESS PLANNING SERVICES			61,890
26	CEO SUPPORT			353,582
27	COMPLIANCE & ETHICS SUPPORT			7,960
28	CORPORATE RELATIONS SUPPORT			31,528
29	CORPORATE SUSTAINABILITY SUPPORT			180,688
30	CONSULTING SERVICES			5,250
31	FINANCIAL FORECASTING AND ANALYSIS			151,499
32	FLEET SERVICES			22,304
33	HUMAN RESOURCES SUPPORT			101,806
34	INTERNAL AUDIT SERVICES			5,899
35	INVESTOR RELATIONS SUPPORT			55,039
36	INFORMATION TECHNOLOGY			438,318
37	LEGAL			167,329
38	MISC EXPENSE			4,822
39	PERMIT EXPENSE			1,864
40	POLITICAL CONTRIBUTION			6,668
41	AFFILIATE RULES COMPLIANCE SUPPORT			22,570
42	REAL ESTATE AND FACILITY			1,022,684
1	**Non-power Goods or Services Provided by Affiliated**			
2				

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
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	(page 2)	PG&E Corporation	930.2	
22	STRATEGIC ANALYSIS SUPPORT			57,026
23	SOURCING SUPOORT			124,170
24	SECURITY SUPPORT			314,160
25	STRATEGY SUPPORT			43,788
26	TAX SERVICES			45,443
27	EMPLOYEE TRANSFER FEE			2,907,411
28	INTEREST			37,494
29	IT CAPITAL RELATED SERVICES			113,374
30				
31	TOTAL - A&G DIRECT CHARGES TO PG&E			7,703,137
32				
33		FUELCO	930.2	
34	ACCOUNTING			18,288
35	CFO SUPPORT			6,096
36	FUEL PURCHASING SUPPORT			417,183
37	LEGAL			15,641
38				
39	TOTAL - A&G DIRECT CHARGES TO FUELCO			457,208
40				
41				
42	TOTAL NON-POWER GOODS/SRV PROVIDED FOR			8,160,345
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
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				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				

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

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
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	03/09/2018	2017/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 3 Column: a

1. Allocation of Corporation cost center costs were based on one of the following factors:

(A) 3-Factor Method (99.84%)
It is the 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 Costs
(c) Affiliate Headcount/Total Consolidated Headcount

(B) Capitalization (100%)
Affiliate Capitalization/Total Consolidated Capitalization

(C) Headcount (99.84%)
Affiliate Headcount/Total Consolidated Headcount

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