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 2016/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 1,144 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 150 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 2016/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 JENNIFER GARDYNE	06 Title of Contact Person SR. DIRECTOR, CORP ACCOUNTING

07 Address of Contact Person *(Street, City, State, Zip Code)*
77 BEALE STREET, MAIL CODE B7A, P.O. BOX 770000, SAN FRANCISCO, CA 94177

08 Telephone of Contact Person,*Including Area Code* (415) 973-8256	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 03/31/2017

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 02 Title VP, CONTROLLER, UTILITY CFO	03 Signature DAVID THOMASON	04 Date Signed *(Mo, Da, Yr)* 03/31/2017

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	03/31/2017	End of 2016/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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	03/31/2017	End of 2016/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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

CONTROL OVER RESPONDENT

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

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Eureka Energy Company	Formerly managed	100	
2		the Utility's Utah coal		
3		venture. Currently holds		
4		part of the Marre Ranch		
5		property in San Luis		
6		Obispo County.		
7				
8	Midway Power, LLC	Formed to be the ownership	100	
9		entity for real estate and		
10		licenses for a suspended		
11		development project.		
12				
13	Natural Gas Corporation of California (NGC)	Entity used to amortize	100	
14		remaining Gas		
15		Exploration and		
16		Development Account		
17		assets.		
18				
19	FuelCo LLC	Formed to share costs and	50	1
20		reduce fuel acquisition		
21		costs.		
22				
23	Pacific Energy Fuels Company	Formed to own and	100	
24		finance the nuclear fuel		
25		inventory previously owned		
26		by Pacific Energy Trust		
27				

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.
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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	Merritt Community Capital Fund V, L.P.	Formed to construct and own	2.4	2
10		low-income housing.		
11				
12	Morro Bay Mutual Water Company	Formed to jointly hold	50	3
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	4
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	5
23		develop, produce, acquire,		
24		and market oil and gas		
25		reserves in Alaska.		
26				
27				

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.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	STARS Alliance, LLC	Formed to increase efficiency	25	6
2		and reduce costs related to		
3		the operation of the members		
4		nuclear generation		
5		facilities.		
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Schedule Page: 103 Line No.: 19 Column: d

Members include: Union Electric Company d/b/a AmerenMO.

Schedule Page: 103.1 Line No.: 9 Column: d

7/26/2016 - Certificate of cancellation filed

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, 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	695,833
2	President, Gas	Nickolas Stravropoulos	660,833
3	Senior VP, Generation and Chief Nuclear Officer	Edward D. Halpin	572,000
4	Senior VP and Chief Information Officer	Karen A. Austin	551,383
5	Senior VP and Chief Ethics and Compliance Officer	Julie M. Kane	440,000
6	Senior VP, Gas Operations	Jesus Soto, Jr.	424,500
7	Senior VP, Safety and Shared Services	Desmond A. Bell	422,733
8	Senior VP, External Affairs and Public Policy	Helen A. Burt	410,350
9	Senior VP, Human Resources	Dinyar B.Mistry	405,700
10	Senior VP and Chief Customer Officer	Loraine M. Giammona	392,000
11	Senior VP, Energy Policy and Procurement	Fong Wan	377,767
12	Senior VP, Regulatory Affairs	Steven Malnight	366,117
13	Senior VP, Electric Transmission and Distribution	Patrick M. Hogan	349,050
14	Vice President, Chief Financial Officer and Controller	David S. Thomason	257,432
15	Senior VP, Electric Transmission and Distribution	Gregory K. Kiraly	68,587
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Schedule Page: 104 Line No.: 9 Column: b

Mr. Mistry was promoted to Senior VP, Human Resources on March 1, 2016. In addition, he retained his prior role as Chief Financial Officer and Controller through May 31, 2016.

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

Mr. Hogan was promoted to Senior VP, Electric Transmission and Distribution on March 1, 2016.

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

Mr. Thomason was promoted to VP, Chief Financial Officer and Controller on June 1, 2016.

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

Mr. Kiraly's employment ended March 4, 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	03/31/2017	End of 2016/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
16		
17	Richard C. Kelly	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
20		
21		
22	Roger H. Kimmel	c/o PG&E Corporation
23		77 Beale Street, 32nd Floor
24		San Francisco, CA 94105
25		
26	Richard A. Meserve ***	c/o PG&E Corporation
27		77 Beale Street, 32nd Floor
28		San Francisco, CA 94105
29		
30	Forrest E. Miller ***	c/o PG&E Corporation
31		77 Beale Street, 32nd Floor
32		San Francisco, CA 94105
33		
34	Eric D. Mullins	c/o PG&E Corporation
35		77 Beale Street, 32nd Floor
36		San Francisco, CA 94105
37		
38	Rosendo G. Parra	c/o PG&E Corporation
39		77 Beale Street, 32nd Floor
40		San Francisco, CA 94105
41		
42	Barbara L. Rambo ***	c/o PG&E Corporation
43		77 Beale Street, 32nd Floor
44		San Francisco, CA 94105
45		
46	Anne Shen Smith	c/o PG&E Corporation
47		77 Beale Street, 32nd Floor
48		San Francisco, CA 94105

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		
2	Nickolas Stavropoulos - President, Gas	c/o PG&E Corporation
3		77 Beale Street, 32nd Floor
4		San Francisco, CA 94105
5		
6	Barry Lawson Williams ***	c/o PG&E Corporation
7		77 Beale Street, 32nd Floor
8		San Francisco, CA 94105
9		
10	Geisha J. Williams - President, Electric	c/o PG&E Corporation
11		77 Beale Street, 32nd Floor
12		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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

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

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

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

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

PACIFIC GAS AND ELECTRIC COMPANY
IMPORTANT CHANGES DURING THE YEAR

For the Quarter Ended December 31, 2016

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 January, 20, 2016, the Tranquillity Switching Station was released to operations. This project, located in Fresno County, constructed a new 3 bay, breaker and a half (BAAH) 230 kV Tranquillity Switching Station. This project was built to facilitate the interconnection of a 200 MW solar generation by RE Tranquillity to Pacific Gas and Electric Company's Panoche – Kearney & Panoche – Helm 230 kV Lines.

   On March 22, 2016, the Excelsior Switching Station was released to operations. This project, located in Fresno County, constructed a new 3 bay, breaker and a half (BAAH) 115 kV Excelsior Switching Station. This project was built to facilitate the interconnection of a 60 MW solar generation by Burford Five Points to Pacific Gas and Electric Company's Panoche – Schindler 115 kV Line Nos. 1 & 2.

   On May 19, 2016, the Crow Creek 60 kV Switching Station was released to operations. This project, located in Stanislaus County, constructed a new two bay, breaker and a half (BAAH) 60 kV Crow Creek Switching Station. This project was built to facilitate the interconnection of a 20 MW solar generation by Frontier Solar to Pacific Gas and Electric Company's Salado – Newman 60 kV Line No. 1.

   On September 11, 2016, the Embarcadero – Potrero 230 kV Project was released to operations. This project, located in San Francisco, constructed a new 3.5-mile 230 kV cable between Embarcadero and Potrero substations. The new facilities at Potrero Substation include a 230 kV switchyard and a 230/115 kV transformer. This project provides a third supply line to Embarcadero Substation.

On September 29, 2016, the California Flats Solar 230 kV Switching Station was released to operations. This project, located in San Luis Obispo County, constructed a new two bay, breaker and a half (BAAH) 230 kV California Flats Solar Switching Station. This project was built to facilitate the interconnection of a 280 MW solar generation by California Flats Solar LLC to Pacific Gas and Electric Company's Morro Bay – Gates 230 kV Line No. 2.

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 December 1, 2016, the Utility issued $400 million of 30-year unsecured senior notes with a coupon of 4.00%. The long-term senior notes are authorized by the California Public Utilities Commission ("CPUC") Decision No. 15-01-030.

Also, on December 1, 2016, the Utility issued $250 million of 364-day unsecured senior notes with a variable interest rate at the 3-month LIBOR (London Interbank Offered Rate) plus 0.20%. Short-term borrowings are authorized by CPUC Decision No. 09-05-002.

b) Bank Credit Facilities:

At December 31, 2016, the Utility had $41 million of letters of credit outstanding, $1.0 billion of commercial paper outstanding, and no borrowings under its $3 billion revolving credit facility. The Utility also had a $250 million term loan outstanding.

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

c) Surety Bonds and Financial Guarantees Backed by Insurance:

From January, 1 2016 to March 30, 2016, $497,412 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of March 30, 2016, there was a total of $54,628,767 in long-term surety bond obligations outstanding.

From April, 1 2016 to June 30, 2016, $7,812,979 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of June 30, 2016, there was a total of $46,815,786.46 in long-term surety bond obligations outstanding.

From July, 1 2016 to September 30, 2016, $20,115,056.74in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of September 30, 2016, there was a total of $66,930,843.20 in long-term surety bond obligations outstanding.

From October, 1 2016 to December 31, 2016, $0 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of December 31, 2016, there was a total of $66,930,843.20 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, 2016, 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:

General Wage Increase lump-sum payroll payments for the period Jan through Oct 2016 were made to IBEW and SEIU represented employees on 12/23/16. Below is a summary of payments that were made:

IBEW Hrly	IBEW Slry	SEIU	Total
$ 31,581,660.90	$ 134,615.98	$ 704,773.04	$ 32,421,049.92

Note: The second lump-sum for the period November through December 2016 will be paid in the month of February 2017.

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 Note 13 Commitments and Contingencies of the Notes to Financial Statements on page 123 of the FERC Form No. 1, which discusses materially important pending legal matters.

Further, refer to Part I, Item 3 in PG&E Corporation's and the Utility’s combined

Annual Report on Form 10-K for the year ended December 31, 2016, 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 2016, three beneficial owners of at least 5 percent of PG&E Corporation common stock as of December 31, 2015 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 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, and she is the spouse of David Thomason, who is Vice President, Chief Financial Officer, and Controller of the Utility. During 2016, Ms. Thomason received compensation and related payments and benefits from the Utility with a value of approximately $120,000. Payments provided to Ms. Thomason during 2017 are expected to be similar in nature and value to payments provided during 2016, consistent with the Utility's policies and practices that apply to employee compensation generally, and in excess of 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.

Four copies of PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2016 (including PG&E Corporation's and Pacific Gas and Electric Company's joint 2016 Annual Report) have been filed in accordance with Instruction III(c) of the Instructions for Filing the FERC Form No. 1.

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:

Officers

The following individual became an officer of the Utility:

- Scott T. Sanford, Vice President, Customer Operations

The following individual's titles changed:

- Roy M. Kuga, Vice President, Grid Integration and Innovation (formerly Vice President, Energy Supply Management)
- Albert F. Torres, Vice President (formerly Vice President, Customer Operations)
- James M. Welsch, Vice President, Nuclear Generation (formerly Site Vice President, Diablo Canyon Power Plant)

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

- Anil K. Suri, 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 9,507,360 shares as of September 30, 2016 to 9,516,370 shares as of December 30, 2016. (Approximately 92 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.

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	03/31/2017	End of 2016/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	76,683,196,010	71,575,321,308
3	Construction Work in Progress (107)	200-201	2,183,195,426	2,057,204,814
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		78,866,391,436	73,632,526,122
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	33,823,849,160	32,001,238,924
6	Net Utility Plant (Enter Total of line 4 less 5)		45,042,542,276	41,631,287,198
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	280,145,003	285,001,087
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		402,677,540	387,399,860
10	Spent Nuclear Fuel (120.4)		2,164,292,005	2,067,748,581
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,381,791,989	2,256,442,841
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		465,322,559	483,706,687
14	Net Utility Plant (Enter Total of lines 6 and 13)		45,507,864,835	42,114,993,885
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)		28,119,383	20,327,286
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	49,368,145	40,152,618
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	373,856,814	234,129,712
24	Other Investments (124)		88,957	93,856
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,606,497,177	2,469,600,241
29	Special Funds (Non Major Only) (129)		368,120,654	344,229,090
30	Long-Term Portion of Derivative Assets (175)		140,213,840	169,617,807
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,566,264,970	3,278,150,610
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		68,255,295	56,893,820
36	Special Deposits (132-134)		6,764,423	234,311,946
37	Working Fund (135)		145,905	142,105
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,365,313,422	1,213,643,677
41	Other Accounts Receivable (143)		1,234,905,330	720,951,032
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		58,476,163	53,937,877
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		20,742,129	24,730,333
45	Fuel Stock (151)	227	1,429,732	1,004,654
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	346,493,508	312,558,926
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	403,970,714	266,941,383

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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		373,856,814	234,129,712
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		115,567,316	125,316,011
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		149,578,164	138,886,943
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)		1,098,140,120	855,009,217
62	Miscellaneous Current and Accrued Assets (174)		54,386,274	85,414,486
63	Derivative Instrument Assets (175)		221,422,287	263,442,551
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		140,213,840	169,617,807
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)		4,514,567,802	3,841,561,688
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		117,574,986	117,777,872
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,800,000	0
72	Other Regulatory Assets (182.3)	232	9,306,684,417	8,666,911,679
73	Prelim. Survey and Investigation Charges (Electric) (183)		89,260	30,101
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)		0	16,859
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	57,798,631	48,854,341
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)		95,397,747	115,842,466
82	Accumulated Deferred Income Taxes (190)	234	2,549,460,531	2,084,286,484
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		12,130,805,572	11,033,719,802
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		65,775,410,504	60,324,333,310

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	6,280,547,928	5,445,547,927
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	8,815,133,482	8,312,192,120
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-52,118,510	-50,038,177
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)	2,433,257	3,223,118
16	Total Proprietary Capital (lines 2 through 15)		18,395,190,222	17,060,119,053
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	16,877,100,001	16,099,970,000
19	(Less) Reaquired Bonds (222)	256-257	145,000,000	207,870,000
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)		16,824,052	18,739,361
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		74,086,768	70,661,348
24	Total Long-Term Debt (lines 18 through 23)		16,674,837,285	15,840,178,013
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		30,502,448	48,764,750
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,093,392,860	475,306,520
29	Accumulated Provision for Pensions and Benefits (228.3)		2,548,296,358	2,534,259,377
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,087,354,964	1,034,861,135
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		88,887,394	117,403,844
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		4,684,437,697	3,643,081,915
35	Total Other Noncurrent Liabilities (lines 26 through 34)		9,532,871,721	7,853,677,541
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		1,516,633,001	1,019,197,000
38	Accounts Payable (232)		2,160,397,276	2,264,738,341
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		23,414,183	21,561,694
41	Customer Deposits (235)		231,954,935	237,243,313
42	Taxes Accrued (236)	262-263	147,023,038	32,425,983
43	Interest Accrued (237)		219,472,711	210,157,281
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)		36,323,395	34,402,580
48	Miscellaneous Current and Accrued Liabilities (242)		509,678,150	496,542,387
49	Obligations Under Capital Leases-Current (243)		18,262,304	20,234,323
50	Derivative Instrument Liabilities (244)		127,287,589	171,082,998
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		88,887,394	117,403,844
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)		4,903,878,574	4,392,501,442
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		469,414,203	437,726,305
57	Accumulated Deferred Investment Tax Credits (255)	266-267	128,411,839	130,954,831
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	212,255,529	230,422,155
60	Other Regulatory Liabilities (254)	278	2,227,787,406	2,606,485,396
61	Unamortized Gain on Reaquired Debt (257)		1,008,945	1,155,069
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	307	307
63	Accum. Deferred Income Taxes-Other Property (282)		12,517,825,140	11,466,564,653
64	Accum. Deferred Income Taxes-Other (283)		711,929,333	304,548,545
65	Total Deferred Credits (lines 56 through 64)		16,268,632,702	15,177,857,261
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		65,775,410,504	60,324,333,310

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	17,837,520,495	17,009,666,384		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	10,017,207,909	9,886,586,673		
5	Maintenance Expenses (402)	320-323	1,578,146,187	1,403,571,300		
6	Depreciation Expense (403)	336-337	2,318,104,364	2,216,270,523		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	365,056,901	329,686,099		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		70,005,143	63,581,018		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	537,759,015	497,102,693		
15	Income Taxes - Federal (409.1)	262-263	-102,414,099	-101,114,397		
16	- Other (409.1)	262-263	-19,643,366	94,731,839		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	483,365,700	1,549,010,567		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	139,214,264	1,155,700,268		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)			661,421		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		2	28		
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)		15,108,373,488	14,783,064,598		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,729,147,007	2,226,601,786		

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
13,882,048,118	13,695,879,713	3,955,472,377	3,313,786,671			2
						3
8,010,497,695	7,870,377,304	2,006,710,214	2,016,209,369			4
852,668,218	914,929,161	725,477,969	488,642,139			5
1,844,735,417	1,728,219,651	473,368,947	488,050,872			6
						7
260,457,881	230,390,325	104,599,020	99,295,774			8
						9
						10
						11
70,005,143	63,581,018					12
						13
401,070,256	387,952,658	136,688,759	109,150,035			14
-103,711,101	-43,668,897	1,297,002	-57,445,500			15
81,990,553	197,854,696	-101,633,919	-103,122,857			16
449,260,118	893,509,255	34,105,582	655,501,312			17
22,523,442	537,167,850	116,690,822	618,532,418			18
						19
	661,421					20
						21
2	28					22
						23
						24
11,844,450,736	11,705,315,872	3,263,922,752	3,077,748,726			25
2,037,597,382	1,990,563,841	691,549,625	236,037,945			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	03/31/2017	End of 2016/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)		2,729,147,007	2,226,601,786		
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	49,093	1,191,524		
37	Interest and Dividend Income (419)		22,250,938	7,930,273		
38	Allowance for Other Funds Used During Construction (419.1)		112,488,153	106,606,132		
39	Miscellaneous Nonoperating Income (421)		38,384,882	29,518,108		
40	Gain on Disposition of Property (421.1)			248,785		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		173,173,066	145,494,822		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)			132,582		
45	Donations (426.1)		12,965,525	11,816,629		
46	Life Insurance (426.2)					
47	Penalties (426.3)		33,144,344	496,839,806		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		11,340,945	12,178,696		
49	Other Deductions (426.5)		775,085,215	631,207,567		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		832,536,029	1,152,175,280		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	351,984	344,953		
53	Income Taxes-Federal (409.2)	262-263	49,511	65,328		
54	Income Taxes-Other (409.2)	262-263	-18,424,592	-58,761,109		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	6,702,261	33,291,946		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	135,763,621	376,247,024		
57	Investment Tax Credit Adj.-Net (411.5)		-4,024,778	-3,934,593		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-151,109,235	-405,240,499		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-508,253,728	-601,439,959		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		776,036,604	726,652,517		
63	Amort. of Debt Disc. and Expense (428)		28,859,372	31,795,041		
64	Amortization of Loss on Reaquired Debt (428.1)		20,530,674	22,038,555		
65	(Less) Amort. of Premium on Debt-Credit (429)		1,915,309	1,728,535		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		146,125	146,465		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		47,182,819	32,455,716		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		51,347,450	47,923,080		
70	Net Interest Charges (Total of lines 62 thru 69)		819,200,585	763,143,749		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,401,692,694	862,018,078		
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)		1,401,692,694	862,018,078		

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:

	2016		2015	
	Revenues	Expenses	Revenues	Expenses
Electric	44,898,176	66,448,741	42,247,495	61,577,902
Gas	162,540,914	140,990,349	143,846,938	124,516,531
Total	207,439,090	207,439,090	186,094,433	186,094,433

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	03/31/2017	End of 2016/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		8,095,695,738	7,981,987,690
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)		1,401,643,601	860,826,554
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	-22,090,165	(19,147,365)
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-22,090,165	(19,147,365)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25	Preferred Dividends		-13,916,354	(13,916,356)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-13,916,354	(13,916,356)
30	Dividends Declared-Common Stock (Account 438)			
31				
32	Common Stock Dividends		-911,000,000	(716,000,000)
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-911,000,000	(716,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		2,129,427	1,945,215
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		8,576,546,935	8,095,695,738
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40	Reserves for excess earnings on FERC hydroelectric			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41	project licenses pursuant to Federal Power Act Section 10 (d)		22,090,165	19,147,365
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		22,090,165	19,147,365
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		216,496,382	197,349,017
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		238,586,547	216,496,382
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		8,815,133,482	8,312,192,120
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-50,038,177	(49,284,486)
50	Equity in Earnings for Year (Credit) (Account 418.1)		49,093	1,191,524
51	(Less) Dividends Received (Debit)			
52	Other Adjustments (offset to 216)		-2,129,426	(1,945,215)
53	Balance-End of Year (Total lines 49 thru 52)		-52,118,510	(50,038,177)

Schedule Page: 118 Line No.: 9 Column: c

As of the filing date of this report, Pacific Gas & Electric Company has applied for FERC approval to charge amounts to Account 439, Adjustments to retained earnings.

Amount represents the cumulative-effect adjustment for the implementation of ASU 2016-09, Compensation - Stock Compensation (Topic 718), relating to the excess tax benefits and deficiencies that were previously recognized in additional paid-in capital.

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, 2016:

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

The following is the detail of dividends declared on First Preferred Stocks for the year ended December 31, 2015:

Class of Stock	No. of Shares	Annual 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	1,613,106
5.00% Cumulative, Non-Redeemable	400,000	1.250	500,001
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			$13,916,356

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, 2016.

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, 2015.

Schedule Page: 118 Line No.: 52 Column: c

This is comprised of the following:

	2016	2015
Utility subsidiary earnings reflected in operations and maintenance accounts	($ 1,265,841)	($1,945,215)
Reclassification to Account 216 of equity of dissolved subsidiary	(863,585)	-
Total	($ 2,129,427)	($1,945,215)

Schedule Page: 118 Line No.: 52 Column: d

Refer to the footnote on Line 52, 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	03/31/2017	End of 2016/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)	1,401,692,694	862,018,078
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	2,683,161,265	2,545,956,622
5	Amortization of		
6	Unamortized Loss or Gain on Reacquired Debt	25,843,827	23,886,143
7	Expenses, Descount and Premium - Long Term Debt	9,406,456	17,008,272
8	Deferred Income Taxes (Net)	1,019,090,904	717,978,836
9	Investment Tax Credit Adjustment (Net)	-4,024,778	-3,934,593
10	Net (Increase) Decrease in Receivables	-1,044,170,612	-316,860,645
11	Net (Increase) Decrease in Inventory	-24,610,966	37,788,491
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	120,266,795	193,624,486
14	Net (Increase) Decrease in Other Regulatory Assets	-854,099,084	-874,286,262
15	Net Increase (Decrease) in Other Regulatory Liabilities	-287,473,741	572,472,642
16	(Less) Allowance for Other Funds Used During Construction	112,488,153	106,606,132
17	(Less) Undistributed Earnings from Subsidiary Companies	9,215,527	668,542
18	Other (provide details in footnote):	1,396,434,543	53,944,503
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	4,319,813,623	3,722,321,899
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-5,708,003,565	-5,189,879,527
27	Gross Additions to Nuclear Fuel	-113,641,852	-88,383,294
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-112,488,153	-106,606,132
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-5,709,157,264	-5,171,656,689
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	12,907,267	21,512,892
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
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	2,116,947	2,585,938
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Net (Increase) Decrease in Restricted Cash	227,547,523	63,476,894
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	1,295,192,896	1,269,082,230
55	Purchases of nuclear decommissioning trust investments and Other	-1,352,469,466	-1,392,384,267
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-5,523,862,097	-5,207,383,002
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	983,900,644	1,122,764,475
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	491,456,708	382,934,742
67	Other (provide details in footnote):		
68	Equity contribution from PG&E Corporation	835,000,000	705,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	2,310,357,352	2,210,699,217
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-160,000,000	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Customer Advances for Construction	31,687,898	35,177,073
78	Net Decrease in Short-Term Debt (c)		
79	Other	-41,715,147	-26,727,339
80	Dividends on Preferred Stock	-13,916,354	-13,916,356
81	Dividends on Common Stock	-911,000,000	-716,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	1,215,413,749	1,489,232,595
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	11,365,275	4,171,492
87			
88	Cash and Cash Equivalents at Beginning of Period	57,035,925	52,864,433
89			
90	Cash and Cash Equivalents at End of period	68,401,200	57,035,925

Schedule Page: 120 Line No.: 13 Column: c

This amount has been restated due to the adoption of ASU 2016-09, which requires, on a retrospective basis, that employee taxes paid for withheld shares be classified as cash flows from financing activities rather than as cash flows from operating activities. This change resulted in an increase to cash flows from operating activities and a decrease to cash flows from financing activities of $26,843,200 for the year ended December 31, 2015.

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

This consists of the following:

	2016	2015
Disallowed Capital Expenditures	$ 507,198,621	$ 407,495,789
Decrease in Other Working Capital	28,527,020	(282,588,834)
Increase (Decrease) - Other Noncurrent Liabilities	739,365,602	(118,337,327)
Others		
Nuclear Fuel Lease Amortization	125,349,148	122,902,702
Payment on capital lease obligation	(20,234,320)	(21,189,720)
Collateral Posted	44,312,983	(18,603,931)
Bad Debt Expense	50,486,925	42,638,415
Tax benefit on stock option exercises*	4,805,641	(5,749,928)
Other-net	(83,377,077)	(72,622,663)
Total	$ 1,396,434,543	$ 53,944,503

* As of Q4'2016, all tax effected book/tax differences on stock based compensation are classified as operating activities in the statement of cash flow under ASU 2016-09. Previously, tax benefits were not allowed to be offset against detriments on the statement of cash flows. Tax benefits were reported in the financing section and detriments were reported in the operating section. Now, both benefits and detriments are reported in the operating section. The 2015 tax benefit on stock option exercises are presented gross in accordance with the guidance that was applicable in 2015.

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

Refer to the footnote on Line 18, column B.

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

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

	2016	2015
Purchases of Nuclear Decommissioning Trust Investments	$1,352,474,365	$1,392,393,525
Decrease in other investments	(4,899)	(9,258)
Total	$1,352,469,466	$1,392,384,267

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

Refer to the footnote on Line 55, column B.

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

This consists of the following:

	2016	2015
Increase (Decrease) in customer deposits	$ (5,288,379)	$ 1,319,962

Debt Issuance Costs - ST Borrowings	(1,853,073)	(2,479,075)
Tax benefit on stock option exercises*	0	1,274,974
Employee taxes paid for withheld shares**	(34,573,697)	(26,843,200)
Total	$ (41,715,147)	$ (26,727,339)

* As of Q4'2016, all tax effected book/tax differences on stock based compensation are classified as operating activities in the statement of cash flow under ASU 2016-09. Previously, tax benefits were not allowed to be offset against detriments on the statement of cash flows. Tax benefits were reported in the financing section and detriments were reported in the operating section. Now, both benefits and detriments are reported in the operating section. The 2015 tax benefit on stock option exercises are presented gross in accordance with the guidance that was applicable in 2015.

**ASU 2016-09 also requires, on a retrospective basis, that employee taxes paid for withheld shares be classified as cash flows from financing activities rather than as cash flows from operating activities. As such, the statements of cash flows for the Utility for the prior period presented was restated. This change resulted in an increase to cash flows from operating activities and a decrease to cash flows from financing activities of $34.6 million and $26.8 million for the years ended December 31, 2016, and 2015, respectively.

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

Refer to the footnote on Line 79, column B.

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

This consists of the following:

	2016	2015
Cash (131)	$ 68,255,295	$ 56,893,820
Working Funds (135)	145,905	142,105
Total	$ 68,401,200	$ 57,035,925

Supplemental disclosures of cash flow information (in millions):

Cash paid for:		
Interest (net of amounts capitalized)	$ (717)	$ (675)
Income taxes paid (refunded), net	244	77
Supplemental disclosures of noncash investing and financing activities:		
Capital expenditures financed through accounts payable	403	440
Terminated capital leases	18	-

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

Refer to the footnote on Line 90, column B.

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	03/31/2017	End of 2016/Q4

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, 2016, as filed with the Securities and Exchange Commission ("SEC") on February 16, 2017. 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 1 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, (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, 2016 up to February 16, 2017, 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 31, 2017. These financial statements include all necessary adjustments and disclosures resulting from these evaluations. The identified subsequent events are as follows:

On March 28, 2017, the Cities of San Bruno and San Carlos, ORA, the SEC, TURN and the Utility (together, the "parties") jointly submitted to the CPUC a settlement agreement (the "settlement agreement") in connection with the order instituting an investigation into the Utility's compliance with the CPUC's ex parte communication rules (the "proceeding") and jointly moved for its approval.

Pursuant to the settlement agreement, the Utility agreed to a total financial remedy of $86.5 million comprised of: a $1 million payment to the California General Fund; forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million); a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over its next GRC cycle, (i.e. the GRC following the 2017 GRC); and compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). Adjustments to revenue requirements would be recorded in the periods in which they are incurred.

The CPUC may accept, reject or modify the terms of the settlement agreement, including imposing additional penalties on the Utility. The Utility is unable to predict the outcome of this proceeding.

Energy Storage Assets (FERC Order No. 784):

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

Energy Plant Account

Energy storage assets totaled $32,142,500 at December 31, 2016, 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 ($185,288) for the year ended December 31, 2016, 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 $68,549 for the year ended December 31, 2016, of which $0 is recorded in account 582 and $68,549 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 $425,264 for the year ended December 31, 2016, of which $0 is recorded in account 570 and $425,264 is recorded in account 592. Amounts associated with distribution functional use would have been recorded in account 592.2 and amounts associated with production functional use would have been recorded in account 553.1, in accordance with FERC Order No. 784. Please see table below.

Other Expense Accounts

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

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

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

Energy Storage Operations (Small Plants)

Line no.	Name of Energy Storage Project	Functional classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Vaca-Dixon	Production	Vacaville, CA	$11,286,007	$34,275	$212,647	$0	($185,288)	$0
2	Hitachi	Distribution	San Jose, CA	$20,856,493	$34,275	$212,617	$0	$0	$0
Totals				**$32,142,500**	**$68,549**	**$425,264**	**$0**	**($185,288)**	**$0**

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 would 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.

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's ability to recover a significant portion of its authorized revenue requirements through rates is generally independent, or "decoupled," from the volume of the Utility's electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

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

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

Revenue Recognition

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 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 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.

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.

Restricted Cash

Prior to October 2016, restricted cash primarily consisted of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 below.)

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)	2016	2015
Electricity generating facilities (1)	5 to 100	$ 11,308	$ 9,860
Electricity distribution facilities	15 to 55	29,836	28,476
Electricity transmission facilities	15 to 75	11,412	10,196
Natural gas distribution facilities	5 to 60	11,362	10,397
Natural gas transmission and storage facilities	5 to 65	6,491	6,352
Construction work in progress		2,184	2,059
Total property, plant, and equipment		**72,593**	**67,340**
Accumulated depreciation		(22,012)	(20,617)
Net property, plant, and equipment		**$ 50,581**	**$ 46,723**

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 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 3.73% in 2016, 3.80% in 2015, and 3.77% in 2014. 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 $51 million and $112 million during 2016, $48 million and $107 million during 2015, and $45 million and $100 million during 2014.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2016 and 2015, including nuclear decommissioning obligations:

(in millions)	2016	2015
ARO liability at beginning of year	$ 3,643	$ 3,575
Revision in estimated cash flows	968	13
Accretion	194	169
Liabilities settled	(121)	(114)
ARO liability at end of year	**$ 4,684**	**$ 3,643**

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 or land to the conditions under certain agreements.

Nuclear Decommissioning Obligation

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. In March 2016, the Utility submitted its updated decommissioning cost estimate to the CPUC. As a result, the estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion. The change in total estimated cost resulted in an $818 million adjustment to the ARO. The adjustment was a result of increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 (Unit 1) and 2025 (Unit 2). The application includes a joint proposal between the Utility and certain interested parties, entered into on June 20, 2016, which resulted in a $115 million increase to the ARO recognized on the Consolidated Balance Sheets in June 2016.

The Utility adjusts its nuclear decommissioning obligation to reflect changes in the estimated costs of decommissioning its nuclear power facilities and records this as an adjustment to the ARO liability on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $3.5 billion and $2.5 billion at December 31, 2016 and 2015, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $5.1 billion and $3.5 billion at December 31, 2016 and 2015 (or $7.3 billion in future dollars), respectively. These estimates are based on the 2016 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, 2016, 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, 2016, 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.

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, 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.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2015 consisted of the following:

(in millions, net of income tax)	**Pension Benefits**	**Other Benefits**	**Other Investments**	**Total**
Beginning balance	$ (21)	$ 15	$ 17	$ 11
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss (net of taxes of $51, $21, and $0, respectively)	(76)	(31)	-	(107)

Regulatory account transfer (net of taxes of $51, $21, and $0, respectively)	73	31	-	104
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (net of taxes of $7, $8, and $0, respectively) (1)	8	11	-	19
Amortization of net actuarial loss (net of taxes of $4, $1, and $0, respectively) (1)	6	3	-	9
Regulatory account transfer (net of taxes of $10, $9, and $0, respectively) (1)	(13)	(13)	-	(26)
Realized gain on investments (net of taxes of $0, $0, and $12, respectively)	-	-	(17)	(17)
Net current period other comprehensive loss	**(2)**	**1**	**(17)**	**(18)**
Ending balance	**$ (23)**	**$ 16**	**$ -**	**$ (7)**

(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.

Recently Adopted Accounting Guidance

Share-Based Payment Accounting

In March 2016, the FASB issued ASU No. 2016-09, *Compensation – Stock Compensation (Topic 718)*, which amends the existing guidance relating to the accounting for share-based payment awards issued to employees, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. PG&E Corporation and the Utility have adopted this standard as of the fourth quarter of 2016.

ASU 2016-09 requires recognition of excess tax benefits and deficiencies in the income statement, which resulted in the recognition of $6.3 million in income tax benefit for PG&E Corporation and the Utility for the year ended December 31, 2016. Previously, these amounts were recognized in additional paid-in capital. Previously unrecognized excess tax benefits were reclassified via a cumulative-effect adjustment. ASU 2016-09 also requires excess tax benefits and deficiencies to be prospectively excluded from assumed future proceeds in the calculation of diluted shares when calculating diluted earnings per share utilizing the treasury stock method. The effect of this change on diluted EPS is immaterial. Additionally, excess income tax benefits from stock-based compensation arrangements are now classified as cash flows from operating activities rather than as cash flows from financing activities, which resulted in an increase to cash flows from operating activities of approximately $7.2 million for the year ended December 31, 2016.

Furthermore, ASU 2016-09 requires, on a retrospective basis, that employee taxes paid for withheld shares be classified as cash flows from financing activities rather than as cash flows from operating activities. As such, the consolidated statements of cash flows for PG&E Corporation and the Utility for the prior periods presented were restated. This change resulted in an increase to cash flows from operating activities and a decrease to cash flows from financing activities of $34.6 million, $26.8 million, and $13.2 million for the years ended December 31, 2016, 2015, and 2014, respectively.

PG&E Corporation and the Utility have elected to continue to estimate forfeitures expected to occur to determine the amount of compensation cost to be recognized in each period and have not changed their policy on statutory withholding requirements and will continue to allow the employee to withhold up to the minimum statutory withholding requirements.

Fair Value Measurement

In May 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*, which standardizes reporting practices related to the fair value hierarchy for all investments for which fair value is measured using net asset value per share. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this standard did not have a material impact on their Consolidated Financial Statements. All prior periods presented in these Consolidated Financial Statements reflect the retrospective adoption of this guidance. (See Notes 10 and 11 below.)

Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU No. 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement,* which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this guidance did not have a material impact on their Consolidated Financial Statements.

Presentation of Debt Issuance Costs

In April 2015, the FASB issued ASU No. 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,* which amends the existing guidance relating to the presentation of debt issuance costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this guidance did not have a material impact on their Consolidated Financial Statements. PG&E Corporation and the Utility restated $105 million and $103 million, respectively, of debt issuance costs as of December 31, 2015 with no impact to net income or total shareholders' equity previously reported. All prior periods presented in these Consolidated Financial Statements reflect the retrospective adoption of this guidance.

Accounting Standards Issued But Not Yet Adopted

Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows – Restricted Cash (Topic 230)*, which amends the existing guidance relating to the disclosure of restricted cash and restricted cash equivalents on the statement of cash flows. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Statements of Cash Flows.

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 recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheet, which were previously not recognized. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019 with retrospective application. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related 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 and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which amends existing revenue recognition guidance, effective January 1, 2018. 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, jurisdiction, and capital markets and to provide more useful information to users of financial statements through improved disclosure requirements. PG&E Corporation and the Utility do not plan to early adopt the standard and are currently reviewing all revenue streams and evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures. The Utility does not expect ASU 2014-09 to materially impact the timing or recognition of revenue generated through the sale and delivery of electricity and natural gas to customers. However, the Utility continues to consider the impacts of outstanding industry-related issues being addressed by the American Institute of CPAs' Revenue Recognition Working Group and the FASB's Transition Resource Group.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

	Balance at December 31,		**Recovery**
(in millions)	**2016**	**2015**	**Period**
Pension benefits (1)	$ 2,429	$ 2,414	Indefinitely (3)
Deferred income taxes (1)	3,859	3,054	47 years
Utility retained generation (2)	364	411	9 years
Environmental compliance costs (1)	778	748	32 years
Price risk management (1)	92	138	10 years
Unamortized loss, net of gain, on reacquired debt (1)	76	94	26 years
Other	353	170	Various
Total long-term regulatory assets	**$ 7,951**	**$ 7,029**	

(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.

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 regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	**2016**	**2015**
Cost of removal obligations (1)	$ 5,060	$ 4,605
Recoveries in excess of AROs (2)	626	631
Public purpose programs (3)	567	600

Other	552	485
Total long-term regulatory liabilities	**$ 6,805**	**$ 6,321**

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

(2) 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.)

(3) 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:

	Receivable Balance at December 31,	
(in millions)	**2016**	**2015**
Electric distribution	$ 132	$ 380
Utility generation	48	122
Gas distribution and transmission	541	493
Energy procurement	132	262
Public purpose programs	106	155
Other	541	348
Total regulatory balancing accounts receivable	**$ 1,500**	**$ 1,760**

	Payable Balance at December 31,	
(in millions)	**2016**	**2015**
Gas distribution and transmission	$ 48	$ -
Energy procurement	13	112
Public purpose programs	264	244
Other	320	359
Total regulatory balancing accounts payable	**$ 645**	**$ 715**

The electric distribution and utility generation accounts track the collection of revenue requirements approved in the GRC. 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)		**2016**	**2015**
PG&E Corporation			
Senior notes:			
Maturity	Interest Rates		
2019	2.40%	$ 350	$ 350
Unamortized discount, net of premium and debt issuance costs		(2)	(2)
Total PG&E Corporation long-term debt		**348**	**348**
Utility			
Senior notes:			
Maturity	Interest Rates		
2017	5.625%	700	700
2018	8.25%	800	800
2020	3.50%	800	800
2021	3.25% to 4.25%	550	550
2022 through 2046	2.45% to 6.35%	12,775	11,775
Less: current portion		(700)	-
Unamortized discount, net of premium and debt issuance costs		(161)	(156)
Total senior notes, net of current portion		**14,764**	**14,469**
Pollution control bonds:			
Maturity	Interest Rates		
Series 2004 A-D, due 2023[1]	4.75%	345	345
Series 2009 A-D, due 2026 [2]	variable rate[4]	149	309
Series 1996 C, E, F, 1997 B due 2026[3]	variable rate[5]	614	614
Less: current portion		-	(160)
Total pollution control bonds		**1,108**	**1,108**
Total Utility long-term debt, net of current portion		**15,872**	**15,577**
Total consolidated long-term debt, net of current portion		**$ 16,220**	**$ 15,925**

(1) The Utility has obtained credit support from an insurance company for these bonds.

(2) Each series of these bonds is supported by a separate direct-pay letter of credit. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent. Series C and D pollution control bonds were redeemed on November 30, 2016.

(3) 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.

(4) At December 31, 2016, the interest rate on these bonds was 0.74%.

(5) At December 31, 2016, the interest rate on these bonds ranged from 0.72% - 0.73%.

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, 2016 are reflected in the table below:

(in millions, except interest rates)	2017	2018	2019	2020	2021	Thereafter	Total
PG&E Corporation							
Average fixed interest rate	-	-	2.40%	-	-	-	2.40%
Fixed rate obligations	$ -	$ -	$ 350	$ -	$ -	$ -	$ 350
Utility							
Average fixed interest rate	5.625%	8.25%	-	3.50%	3.80%	4.84%	4.94%
Fixed rate obligations	$700	$800	$-	$800	$550	$13,120	$15,970
Variable interest rate as of December 31, 2016	-	-	0.74%	0.73%	-	-	0.73%
Variable rate obligations (1)	$ -	$ -	$ 149	$ 614	$ -	$ -	$ 763
Total consolidated debt	**$ 700**	**$ 800**	**$ 499**	**$ 1,414**	**$ 550**	**$ 13,120**	**$ 17,083**

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

Short-term Borrowings

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at December 31, 2016:

(in millions)	Termination Date	Credit Facility Limit		Letters of Credit Outstanding	Commercial Paper Outstanding	Facility Availability
PG&E Corporation	April 2021	$ 300	(1)	$ -	$ -	$ 300
Utility	April 2021	3,000	(2)	41	1,016	1,943
Total revolving credit facilities		**$ 3,300**		**$ 41**	**$ 1,016**	**$ 2,243**

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

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

For the year ended December 31, 2016, PG&E Corporation's average outstanding commercial paper balance was $84 million and the maximum outstanding balance during the year was $176 million. For 2016, the Utility's average outstanding commercial paper balance was $837 million and the maximum outstanding balance during the year was $1.4 billion. There were no bank borrowings for PG&E Corporation or the Utility in 2016.

Revolving Credit Facilities

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021. 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. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for one additional period.

Borrowings under each credit agreement (other than swingline loans) will bear interest based, at each borrower's election, on (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 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 own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

Commercial Paper Programs

The borrowings from PG&E Corporation's and the Utility's commercial paper programs 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 2016, the average yield on outstanding PG&E Corporation and Utility commercial paper was 0.63% and 0.64%, respectively.

Other Short-term Borrowings

In March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. Additionally, in December 2016, the Utility issued a $250 million unsecured senior floating rate note that matures on November 30, 2017. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 506,891,874 shares of common stock outstanding at December 31, 2016. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2016.

During 2016, PG&E Corporation sold 2.6 million shares of common stock under the February 2015 equity distribution agreement for cash proceeds of $149 million, net of commissions paid of $1.3 million. As of December 31, 2016, the remaining gross sales available under this agreement were $275 million.

In August 2016, PG&E Corporation sold 4.9 million shares of its common stock in an underwritten public offering for net cash proceeds of $309 million.

In addition, during 2016, 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 $364 million.

Dividends

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. For the first quarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. In May 2016, the Board of Directors of PG&E Corporation adopted a new quarterly common stock dividend of $0.49 per share. In 2016, total dividends were $1.925 per share.

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%. Additionally, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on a weighted average over five years. At December 31, 2016, the Utility had restricted net assets of $15.8 billion and was limited to $25 million of additional common stock dividends it could pay to PG&E Corporation.

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 13,826,995 shares were available for future awards at December 31, 2016.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2016, 2015, and 2014:

(in millions)	2016	2015	2014
Restricted stock units	$ 53	$ 47	$ 42
Performance shares	55	46	36
Total compensation expense (pre-tax)	**$ 108**	**$ 93**	**$ 78**
Total compensation expense (after-tax)	**$ 64**	**$ 55**	**$ 47**

The amount of share-based compensation costs capitalized during 2016, 2015, and 2014 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Restricted Stock Units

Prior to 2014, restricted stock units generally vested over four years in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Restricted stock units granted after 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2016, 2015, and 2014 was $56.68, $53.30, and $43.76, respectively. The total fair value of restricted stock units that vested during 2016, 2015, and 2014 was $36 million, $57 million, and $34 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, 2016, $37 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.22 years.

The following table summarizes restricted stock unit activity for 2016:

	Number of	Weighted Average Grant-

	Restricted Stock Units	Date Fair Value
Nonvested at January 1	1,972,899	$ 47.33
Granted	776,312	$ 56.68
Vested	(770,968)	$ 46.79
Forfeited	(55,233)	$ 49.65
Nonvested at December 31	**1,923,010**	$ 51.26

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 2016, 2015, and 2014 was $53.61, $68.27, and $51.81 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, 2016, $40 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.57 years.

The following table summarizes activity for performance shares in 2016:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,450,612	$ 59.24
Granted	1,233,884	53.61
Vested	(777,719)	51.81
Forfeited (1)	(67,922)	58.20
Nonvested at December 31	**1,838,855**	$ 58.65

(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, 2016 and December 31, 2015, 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, 2016, 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, 2016, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid $14 million of dividends on preferred stock in each of 2016, 2015, and 2014.

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 2016, 2015, and 2014.

	Year Ended December 31,		
(in millions, except per share amounts)	**2016**	**2015**	**2014**
Income available for common shareholders	$ 1,393	$ 874	$ 1,436
Weighted average common shares outstanding, basic	499	484	468
Add incremental shares from assumed conversions:			
Employee share-based compensation	2	3	2
Weighted average common share outstanding, diluted	501	487	470
Total earnings per common share, diluted	**$ 2.78**	**$ 1.79**	**$ 3.06**

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)	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Current:						
Federal	$ (105)	$ (89)	$ (84)	$ (105)	$ (88)	$ (84)
State	(70)	11	(41)	(66)	6	(29)
Deferred:						
Federal	218	131	396	229	136	426
State	16	(76)	78	16	(69)	75
Tax credits	(4)	(4)	(4)	(4)	(4)	(4)
Income tax provision (benefit)	**$ 55**	**$ (27)**	**$ 345**	**$ 70**	**$ (19)**	**$ 384**

The following table describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	**2016**	**2015**	**2016**	**2015**
Deferred income tax assets:				
Tax carryforwards	1,851	1,703	1,596	1,462
Other [1]	463	757	402	700
Total deferred income tax assets	**$ 2,314**	**$ 2,460**	**$ 1,998**	**$ 2,162**
Deferred income tax liabilities:				
Property related basis differences	10,429	9,656	10,411	9,638
Income tax regulatory asset [2]	1,572	1,244	1,572	1,245
Other [3]	526	766	525	766
Total deferred income tax liabilities	**$ 12,527**	**$ 11,666**	**$ 12,508**	**$ 11,649**
Total net deferred income tax liabilities	**$ 10,213**	**$ 9,206**	**$ 10,510**	**$ 9,487**

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

(2) Represents the deferred income tax component of the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

(3) Amounts primarily relate to regulatory balancing accounts. Greenhouse gas allowances are temporary timing differences that reverse through 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,					
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
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]	(2.5)	(4.9)	1.4	(2.2)	(4.8)	1.6
Effect of regulatory treatment of fixed asset differences [2]	(23.7)	(33.6)	(15.0)	(23.4)	(33.7)	(14.7)
Tax credits	(0.8)	(1.3)	(0.7)	(0.8)	(1.3)	(0.7)
Benefit of loss carryback	(1.1)	(1.5)	(0.8)	(1.1)	(1.5)	(0.8)
Non deductible penalties [3]	0.8	4.3	0.3	0.8	4.3	0.3

Other, net [4]	(3.9)	(1.1)	(0.8)	(3.5)	(0.2)	0.4
Effective tax rate	**3.8 %**	**(3.1) %**	**19.4 %**	**4.8 %**	**(2.2) %**	**21.1 %**

[1] Includes the effect of state flow-through ratemaking treatment. In 2016 and 2015, amounts include an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions.

[2] Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacts only 2016. 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 non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for the year ended December 31, 2016 and the effects of the Penalty Decision for the year ended December 31, 2015. For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

[4] In 2016, the amount primarily represents the impact of tax audit settlements.

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
(in millions)	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Balance at beginning of year	$ 468	$ 713	$ 666	$ 462	$ 707	$ 660
Additions for tax position taken during a prior year	-	40	7	-	40	7
Reductions for tax position taken during a prior year	(77)	(349)	(9)	(77)	(349)	(9)
Additions for tax position taken during the current year	56	64	61	56	64	61
Settlements	(59)	-	(12)	(59)	-	(12)
Balance at end of year	**$ 388**	**$ 468**	**$ 713**	**$ 382**	**$ 462**	**$ 707**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2016 for PG&E Corporation and the Utility was $25 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, 2016, it is reasonably possible that unrecognized tax benefits will decrease by approximately $70 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

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, 2016, 2015, and 2014, these amounts were immaterial.

IRS settlements

PG&E Corporation previously participated in the Compliance Assurance Process, a real-time IRS audit intended to expedite resolution of tax matters. The Compliance Assurance Process audit culminates with a letter from the IRS indicating its acceptance of the return. PG&E Corporation's participation in the Compliance Assurance Process ended effective with the submission of its 2015 tax return.

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. In March 2016, PG&E Corporation reached an agreement with the IRS on deductible electric transmission and distribution repair costs for the 2012 tax year. 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. Deductible repair costs for other lines of business will continue to be subject to examination by the IRS for subsequent years. The IRS is expected to issue guidance in 2017 that clarifies which repair costs are deductible for the natural gas transmission and distribution businesses.

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

2015 Gas Transmission and Storage Rate Case

In comments to the proposed decision in phase two of the 2015 GT&S rate case, the Utility questioned whether the methodology employed to calculate the capital disallowance portion of the San Bruno penalty might constitute a normalization violation. In recognition of this concern, the CPUC, in the final phase two decision, provided the Utility an opportunity to submit a ruling to the IRS for guidance and establish a memorandum account to track the additional revenue that would be recoverable if the method is deemed to be a normalization violation. The Utility anticipates filing the ruling request in early 2017.

As a result of the final phase two decision, PG&E Corporation and the Utility applied flow through accounting to property-related timing differences for 2016 and 2015.

Carryforwards

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

(in millions)	December 31, 2016	Expiration Year
Federal:		
Net operating loss carryforward	$ 5,009	2029 - 2036
Tax credit carryforward	116	2029 - 2036
Charitable contribution loss carryforward	192	2017 - 2021
State:		
Net operating loss carryforward	$ -	N/A
Tax credit carryforward	51	Various
Charitable contribution loss carryforward	112	2019 - 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, 2016 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 forward contracts, swaps, futures, options, and CRRs.

Derivatives are presented in the Utility's Consolidated Balance Sheets 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, 2016 and 2015, respectively, the volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume	
Underlying Product	**Instruments**	**2016**	**2015**
Natural Gas [1] (MMBtus [2])	Forwards and Swaps	323,301,331	333,091,813
	Options	96,602,785	111,550,004
Electricity (Megawatt-hours)	Forwards and Swaps	3,287,397	3,663,512
	Congestion Revenue Rights [3]	278,143,281	216,383,389

(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, 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**

At December 31, 2015, 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	$ 97	$ (4)	$ 25	**$ 118**
Other noncurrent assets – other	172	(2)	-	**170**
Current liabilities – other	(102)	4	44	**(54)**
Noncurrent liabilities – other	(140)	2	21	**(117)**
Total commodity risk	**$ 27**	**$ -**	**$ 90**	**$ 117**

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

	Commodity Risk		
	For the year ended December 31,		
(in millions)	**2016**	**2015**	**2014**
Unrealized gain/(loss) - regulatory assets and liabilities [1]	$ 64	$ (6)	$ 124
Realized loss - cost of electricity [2]	(53)	(14)	(83)
Realized loss - cost of natural gas [2]	(18)	(10)	(8)
Total commodity risk	**$ (7)**	**$ (30)**	**$ 33**

[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, 2016, 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)	**2016**	**2015**
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (24)	$ (2)
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)**	**$ (2)**

[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.

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, 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**
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.

	Fair Value Measurements At December 31, 2015				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	$ 64	$ -	$ -	$ -	**$ 64**
Nuclear decommissioning trusts					
Short-term investments	36	-	-	-	**36**
Global equity securities	1,520	-	-	-	**1,520**
Fixed-income securities	694	521	-	-	**1,215**
Assets measured at NAV	-	-	-	-	**13**
Total nuclear decommissioning trusts (2)	**2,250**	**521**	**-**	**-**	**2,784**

Price risk management instruments (Note 9)					
Electricity	-	9	259	18	**286**
Gas	-	1	-	1	**2**
Total price risk management instruments	**-**	**10**	**259**	**19**	**288**
Rabbi trusts					
Fixed-income securities	-	57	-	-	**57**
Life insurance contracts	-	70	-	-	**70**
Total rabbi trusts	**-**	**127**	**-**	**-**	**127**
Long-term disability trust					
Short-term investments	7	-	-	-	**7**
Assets measured at NAV	-	-	-	-	**158**
Total long-term disability trust	**7**	**-**	**-**	**-**	**165**
TOTAL ASSETS	**$ 2,321**	**$ 658**	**$ 259**	**$ 19**	**$ 3,428**
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	$ 69	$ 1	$ 170	$ (70)	**$ 170**
Gas	-	2	-	(1)	**1**
TOTAL LIABILITIES	**$ 69**	**$ 3**	**$ 170**	**$ (71)**	**$ 171**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $314 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. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. 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, 2016 and 2015.

Trust Assets

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 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.

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* and applied it retrospectively for the periods presented in their Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, 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. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, 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 forwards and swaps 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 forwards and swaps, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

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

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

Level 3 Measurements and Sensitivity Analysis

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

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

(in millions)	Fair Value at At December 31, 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

(in millions)	Fair Value at At December 31, 2015		Valuation	Unobservable	
Fair Value Measurement	**Assets**	**Liabilities**	**Technique**	**Input**	**Range [1]**
Congestion revenue rights	$ 259	$ 63	Market approach	CRR auction prices	$ (161.36) - 8.76
Power purchase agreements	$ -	$ 107	Discounted cash flow	Forward prices	$ 15.08 - 37.27

(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, 2016 and 2015, respectively:

	Price Risk Management Instruments	
(in millions)	**2016**	**2015**
Asset (liability) balance as of January 1	**$ 89**	**$ 69**
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(34)	20
Asset (liability) balance as of December 31	**$ 55**	**$ 89**

(1) The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

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, 2016 and 2015, 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, 2016 and 2015.

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,			
	2016		2015	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
Debt (Note 4)				
PG&E Corporation	$ 348	$ 352	$ 348	$ 354
Utility	15,813	17,790	14,818	16,422

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, 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**
As of December 31, 2015				
Nuclear decommissioning trusts				
Short-term investments	$ 36	$ -	$ -	$ 36
Global equity securities	508	1,034	(9)	1,533
Fixed-income securities	1,165	58	(8)	1,215
Total (1)	**$ 1,709**	**$ 1,092**	**$ (17)**	**$ 2,784**

(1) Represents amounts before deducting $333 million and $314 million at December 31, 2016 and 2015, 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, 2016
Less than 1 year	$ 13
1–5 years	419
5–10 years	255
More than 10 years	505
Total maturities of fixed-income securities	**$ 1,192**

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

(in millions)	2016	2015	2014
Proceeds from sales and maturities of nuclear decommissioning investments	$ 1,295	$ 1,268	$ 1,336
Gross realized gains on securities held as available-for-sale	18	55	118
Gross realized losses on securities held as available-for-sale	(26)	(37)	(12)

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.

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 2016 and 2015:

Pension Plan

(in millions)	2016	2015
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 13,745**	**$ 14,216**
Actual return on plan assets	1,358	(176)
Company contributions	334	334
Benefits and expenses paid	(708)	(629)
Fair value of plan assets at end of year	**$ 14,729**	**$ 13,745**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 16,299**	**$ 16,696**
Service cost for benefits earned	453	479
Interest cost	715	673
Actuarial (gain) loss	637	(922)
Plan amendments	(91)	1
Transitional costs	-	1
Benefits and expenses paid	(708)	(629)
Benefit obligation at end of year (1)	**$ 17,305**	**$ 16,299**
Funded Status:		
Current liability	$ (7)	$ (6)
Noncurrent liability	(2,569)	(2,547)
Net liability at end of year	**$ (2,576)**	**$ (2,553)**

(1) PG&E Corporation's accumulated benefit obligation was $15.6 billion and $14.7 billion at December 31, 2016 and 2015, respectively.

Postretirement Benefits Other than Pensions

(in millions)	2016	2015
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,035**	**$ 2,092**
Actual return on plan assets	167	(26)
Company contributions	52	61
Plan participant contribution	85	68
Benefits and expenses paid	(166)	(160)
Fair value of plan assets at end of year	**$ 2,173**	**$ 2,035**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,766**	**$ 1,811**
Service cost for benefits earned	52	55
Interest cost	76	71
Actuarial (gain) loss	11	(98)
Plan amendments	37	-
Transitional costs	-	1
Benefits and expenses paid	(153)	(146)
Federal subsidy on benefits paid	3	4
Plan participant contributions	85	68
Benefit obligation at end of year	**$ 1,877**	**$ 1,766**
Funded Status: (1)		
Noncurrent asset	$ 368	$ 344

Noncurrent liability	(72)	(75)
Net asset at end of year	**$ 296**	**$ 269**

(1) At December 31, 2016 and 2015, 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)	**2016**	**2015**	**2014**
Service cost	$ 453	$ 479	$ 383
Interest cost	715	673	695
Expected return on plan assets	(828)	(873)	(807)
Amortization of prior service cost	8	15	20
Amortization of net actuarial loss	24	10	2
Net periodic benefit cost	**372**	**304**	**293**
Less: transfer to regulatory account (1)	(34)	34	42
Total expense recognized	**$ 338**	**$ 338**	**$ 335**

(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)	**2016**	**2015**	**2014**
Service cost	$ 52	$ 55	$ 45
Interest cost	76	71	76
Expected return on plan assets	(107)	(112)	(103)
Amortization of prior service cost	15	19	23
Amortization of net actuarial loss	4	4	2
Net periodic benefit cost	**$ 40**	**$ 37**	**$ 43**

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 2017 are as follows:

(in millions)	Pension Plan	PBOP Plans
Unrecognized prior service cost	$ (7)	$ 15
Unrecognized net loss	22	4
Total	**$ 15**	**$ 19**

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,		
	2016	2015	2014	2016	2015	2014
Discount rate	4.11 %	4.37 %	4.00 %	4.05 - 4.19 %	4.27 - 4.48 %	3.89 - 4.09 %
Rate of future compensation increases	4.00 %	4.00 %	4.00 %	-	-	-
Expected return on plan assets	5.30 %	6.10 %	6.20 %	2.80 - 6.00 %	3.20 - 6.60 %	3.30 - 6.70 %

The assumed health care cost trend rate as of December 31, 2016 was 7.2%, 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	$ 118	$ (120)
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 5.3% compares to a ten-year actual return of 7.3%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 696 Aa-grade non-callable bonds at December 31, 2016. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

Investment Policies and Strategies

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

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

In the Pension Plan, target allocations for 2017 were updated to reflect a 2% increase in global equity investments and a 2% decrease in fixed income investments. Target allocations for PBOP Plans remain unchanged. 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		
	2017	2016	2015	2017	2016	2015
Global equity	27 %	25 %	25 %	32 %	32 %	31 %
Absolute return	5 %	5 %	5 %	3 %	3 %	3 %
Real assets	10 %	10 %	10 %	7 %	7 %	8 %
Fixed income	58 %	60 %	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, 2016 and 2015.

	Fair Value Measurements At December 31,							
	2016				2015			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Pension Plan:								
Short-term investments	$ 364	$ 369	$ -	**$ 733**	$ 247	$ 375	$ -	**$ 622**
Global equity	996	-	-	**996**	903	-	-	**903**
Real assets	610	-	-	**610**	581	-	-	**581**
Fixed-income	1,754	4,774	5	**6,533**	1,841	4,495	3	**6,339**
Assets measured at NAV	-	-	-	**5,950**	-	-	-	**5,308**
Total	**$ 3,724**	**$ 5,143**	**$ 5**	**$ 14,822**	**$ 3,572**	**$ 4,870**	**$ 3**	**$ 13,753**
PBOP Plans:								
Short-term investments	$ 33	$ -	$ -	**$ 33**	$ 20	$ -	$ -	**$ 20**
Global equity	115	-	-	**115**	104	-	-	**104**
Real assets	70	-	-	**70**	69	-	-	**69**
Fixed-income	150	656	-	**806**	150	632	-	**782**

Assets measured at NAV	-	-	-	1,153	-	-	-	1,065
Total	**$ 368**	**$ 656**	**$ -**	**$ 2,177**	**$ 343**	**$ 632**	**$ -**	**$ 2,040**
Total plan assets at fair value				**$ 16,999**				**$ 15,793**

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $97 million and $13 million at December 31, 2016 and 2015, respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

Valuation Techniques

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

Short-Term Investments

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

Global Equity

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

Real Assets

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

Fixed-Income

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

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* and applied it retrospectively for the periods presented in their Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the pension and PBOP plans 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, hedge funds, private real estate funds, and fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

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, 2016 and 2015.

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, 2016 and 2015:

(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**

(in millions) **For the year ended December 31, 2015**	**Fixed-Income**
Balance at beginning of year	$ 12
Actual return on plan assets:	
Relating to assets still held at the reporting date	(3)
Relating to assets sold during the period	1
Purchases, issuances, sales, and settlements:	
Purchases	2
Settlements	(9)
Balance at end of year	**$ 3**

There were no material transfers out of Level 3 in 2016 and 2015.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $334 million to the pension benefit plans and $52 million to the other benefit plans in 2016. 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 2016. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $61 million to the pension plan and other postretirement benefit plans, respectively, for 2017.

Benefits Payments and Receipts

As of December 31, 2016, 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:

	Pension	**PBOP**	**Federal**

(in millions)	Plan	Plans	Subsidy
2017	$ 739	$ 87	$ (8)
2018	781	93	(9)
2019	821	97	(10)
2020	857	103	(10)
2021	892	108	(11)
Thereafter in the succeeding five years	4,879	592	(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 $97 million, $89 million, and $80 million in 2016, 2015, and 2014, 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)	**2016**	**2015**	**2014**
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 7	$ 6	$ 5
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 74	$ 53	$ 54
Utility employee benefit due to PG&E Corporation	91	82	70

At December 31, 2016 and 2015, the Utility had receivables of $18 million and $22 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 $21 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 policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows may be materially affected by the outcome of the following matters.

Enforcement and Litigation Matters

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 October 14, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility submitted a status report to the CPUC which proposed an update to the framework for resolving the proceeding. The revised framework includes a total of 164 communications in the scope of the proceeding. Throughout 2016, the parties jointly submitted stipulations on all of the communications, and on November 30, 2016, the parties began settlement discussions. In the event a settlement cannot be reached, the parties will brief the matter based upon the identified communications and some related discovery as well as factual stipulations and agreed upon issues of policy and law for CPUC resolution. The opening briefs are due on March 24, 2017, and reply briefs are due on April 14, 2017.

The Utility expects that the other parties may argue that the number of violations exceeds the 164 communications referenced in the October 14, 2016 joint status report either because a single communication may have violated more than one rule or because they believe some of the material provided during discovery constitutes impermissible ex parte communications. The Utility expects to contest many of these assertions. If the matter does not settle, the CPUC will determine which communications included within the scope of the proceeding were in violation of its rules. The CPUC will also determine whether to impose penalties or other remedies, as a result of a potential settlement or otherwise. The CPUC can impose fines up to $50,000 for each violation, and up to $50,000 per day if the CPUC determines that the violation was continuing. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; 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 CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII. In light of recent CPUC decisions, such as the Penalty Decision and the decision in the 2015 GT&S rate case, the Utility expects that such penalties could include fines and future revenue requirement reductions. In accordance with accounting rules, revenue requirement reductions would be recorded in the period they are incurred and fines would be recorded when considered probable and their amount or range can be reasonably estimated. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred because it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations.

Finally, 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.

CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices with respect to maintaining safe operation of its natural gas distribution service and facilities. The order also required the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cited the SED’s investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014.

On August 18, 2016, the CPUC approved a final decision in this investigation. The CPUC assessed a fine of $25.6 million. With the $10.85 million citation previously paid in 2015 for the City of Carmel-by-the-Sea (“Carmel”) incident, the total fine imposed on the Utility was $36.5 million. The remaining $25.6 million was paid in September 2016. The decision denied the appeals previously filed by the SED and Carmel from the presiding officer’s decision, and closed this proceeding but allowed the parties an opportunity to request that this proceeding be reopened if needed to ensure proper implementation of a compliance plan to be developed by the parties.

On September 26, 2016, the SED filed an application for rehearing of the CPUC’s decision. Specifically, the application indicates that the CPUC erred in certain of its determinations (including those related to maximum allowable operating pressure documentation that, if adopted, could result in an additional fine of $7 million), calculations (including those related to the missing De Anza records violations) and certain other findings, and requests that the CPUC adopt its recommendations. On October 11, 2016, the Utility submitted its response to the CPUC in which it opposed the SED’s application for rehearing arguing that the application failed to identify a legal error warranting rehearing by the CPUC. The Utility cannot predict when or if the CPUC will grant the rehearing or if it will adopt the SED’s recommendations.

On October 24, 2016 and November 30, 2016, the Utility held meet and confer sessions with parties to develop remedial measures necessary to address the issues identified in the CPUC decision with the objective of establishing a compliance plan. On December 16, 2016, the Utility submitted its Initial Gas Distribution Records Compliance Plan that includes feasible and cost-effective measures necessary to improve natural gas distribution system record-keeping.

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. Under both the gas and electric programs, 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. 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 can consider the discretionary factors discussed above (see "Order Instituting an Investigation into Compliance with Ex Parte Communication Rules" above) in determining the number of violations and whether to impose daily fines for continuing violations. There is also an administrative limit of $8 million per citation issued.

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 Utility believes it is probable that the SED will impose penalties or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations, based on the SED's investigations of incidents reported to the CPUC, or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits or investigations. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED and other CPUC staff has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

In September 2016, the Utility reported that it discovered in November 2015 that approximately 550,000 atmospheric corrosion inspections on above-ground gas distribution meters completed in 2014, which constituted 35% of such inspections in 2014, were performed by non-operator qualified personnel. The Utility did not provide timely notification of such non-compliance to the CPUC. On December 23, 2016, the SED issued the Utility a citation with a $5.45 million fine related to this self-report. The citation included a $5.05 million fine for not ensuring that contractor inspectors were operator-qualified, a $350,000 fine for not completing inspections within 39 months from the previous inspections, and a $50,000 fine for not reporting the self-identified violations within ten days of discovery. The amount of the fine is conditioned upon the Utility implementing certain remedial measures. The Utility paid the fine in January 2017.

In February 2017, the Utility reported that it discovered in April 2014 that customer service representatives who handle gas emergency calls within the Utility's call centers are not included in the drug and alcohol testing program as required by PHMSA regulations. The Utility did not provide timely notification of such non-compliance to the CPUC. The SED could impose fines on the Utility of $50,000 per violation, and also for failure to timely file a self-report in connection with the non-compliance. The SED has the authority to issue more than one citation for a series of related incidents and can impose daily fines for continuing violations, and the CPUC can issue an OII and possible additional fines even after the SED has issued a citation. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines that could be imposed with respect to this self-report, for the reasons indicated above, or to predict whether the CPUC will open a formal proceeding.

Federal Matters

Federal Criminal Trial

On June 14, 2016, a federal criminal trial against the Utility began in the United States District Court for the Northern District of California, in San Francisco, on 12 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility obstructed the NTSB investigation into the cause of the San Bruno accident. On July 26, 2016, the court granted the government's motion to dismiss one count alleging that the Utility knowingly and willfully failed to retain a strength test pressure record with respect to a distribution feeder main, thereby reducing the total number of counts from 13 to 12.

On August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act.

On January 26, 2017, the court issued a judgment of conviction sentencing the Utility to a five-year corporate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service. The Utility has decided not to appeal the convictions. The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017.

At December 31, 2016, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $3 million accrual in connection with this matter. On February 1, 2017, the Utility paid the $3 million fine imposed by the court. The Utility could incur material costs, not recoverable through rates, in the event of non-compliance with the terms of probation and in connection with the monitorship (including but not limited to the monitor's compensation or costs resulting from recommendations of the monitor).

Other Federal 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. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The investigation involves a removal by the Utility of a hazardous tree that contained an osprey nest and egg in Inverness, California, on March 18, 2016. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

Other Matters

Butte Fire Litigation

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. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

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, 2016, 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 involving approximately 1,950 individual plaintiffs representing approximately 950 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 inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling cases. The next case management conference is scheduled for March 2, 2017.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys’ fees without having been found negligent, through the theory 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. The Utility believes it was not negligent; however, there can be no assurance that a court or jury would agree with the Utility. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys’ fees, fire suppression costs, and other damages that the Utility could be liable for under the theories of inverse condemnation and/or negligence.

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	(60)
Balance at December 31, 2016	**$ 690**

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $27 million.

The Utility believes that it is reasonably possible that it will incur losses related to Butte fire claims in excess of $750 million accrued through December 31, 2016 but is currently unable to reasonably estimate the upper end of the range of losses because it is still in an early stage of the evaluation of claims, the mediation and settlement process, and discovery. 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 and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

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 approximately $900 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. The Utility has recorded $625 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, the Utility is pursuing coverage under the insurance policies of its two vegetation management contractors, including under policies where the Utility is listed as an additional insured. Recoveries of any amounts under these policies 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**

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.

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 $45 million at December 31, 2016 and $63 million at December 31, 2015. 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 or projected to be 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 23, 2016 final phase one decision and December 1, 2016 final phase two decision in the Utility's 2015 GT&S rate case, the April 9, 2015 Penalty Decision and the Utility's Pipeline Safety Enhancement Plan 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 decision permanently disallowed a portion of the 2011 through 2014 capital spending in excess of the amount adopted and established various cost caps that will increase the risk of overspend over the current rate case cycle, including new one-way capital 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 to the net plant balance 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.

Penalty Decision's Disallowance of Natural Gas Capital Expenditures

On April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "Penalty Decision"). In January 2016, the CPUC closed the investigative proceedings. The total penalty includes (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million.

On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case, which applies $689 million of the $850 million penalty to capital expenditures. The decision also approves the Utility's list of programs and projects that meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty.

For the twelve months ended December 31, 2016, the Utility recorded charges for disallowed capital spending of $283 million as a result of the Penalty Decision. The cumulative charges at December 31, 2016, and the additional future charges that will be recognized in the first quarter of 2017 are shown in the following table:

(in millions)	Twelve Months Ended December 31, 2016	Cumulative Charges December 31, 2016	Future Charges and Costs	Total Amount
Fine paid to the state	$ -	$ 300	$ -	$ 300
Customer bill credit paid	-	400	-	400
Charge for disallowed capital (1)	283	689	-	689
Disallowed revenue for pipeline safety expenses (2)	129	129	32	161
CPUC estimated cost of other remedies (3)	-	-	-	50
Total Penalty Decision fines and remedies	**$ 412**	**$ 1,518**	**$ 32**	**$ 1,600**

(1) The Penalty Decision disallows the Utility from recovering $850 million in costs associated with pipeline safety-related projects and programs. On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case which allocates $689 million of the $850 million penalty to capital expenditures.

(2) GT&S revenues have been reduced for these unrecovered expenses. The remaining charges will be recognized in the first quarter of 2017.

(3) In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision. This table does not reflect the Utility's remedy-related costs already incurred or the Utility's estimated future remedy-related costs.

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, 2016, the Utility has spent $1.35 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 beyond 2017. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

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 is subjective and 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. 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 2016**	**December 31, 2015**
Topock natural gas compressor station [1]	$ 299	$ 300
Hinkley natural gas compressor station [1]	135	140
Former manufactured gas plant sites owned by the Utility or third parties	285	271
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	131	164
Fossil fuel-fired generation facilities and sites	108	94
Total environmental remediation liability	**$ 958**	**$ 969**

(1) See "Natural Gas Compressor Station Sites" below.

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the EPA under the federal Resource Conversation and Recovery Act as well as 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, 2016 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. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

At December 31, 2016 the Utility expected to recover $671 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

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. One of these stations is located near Needles, California and is referred to below as the "Topock site." Another station is located near Hinkley, California and is referred to below as the "Hinkley site." 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. The DTSC conducted an additional environmental review of the proposed design and issued a draft environmental impact report for public comment in January 2017. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in mid-2017. After the Utility modifies its design in response to the final report, the Utility will seek approval to begin construction of the new in-situ treatment system in late 2017 or early 2018.

Hinkley Site

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume 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 Regional Board. In November 2015, the Regional Board 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.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.9 billion (including amounts related to the Topock and Hinkley sites described above) if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs. 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.

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, 2016, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $60 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 $2 million, as of December 31, 2016.

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 $375 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 $375 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. In connection with the CPUC approved settlement agreement, on April 12, 2004, the Utility deposited approximately $1.7 billion into escrow for the payment of certain disputed claims, previously collected from customers through rates. 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.

On October 13, 2016, the Utility received approval from the bankruptcy court to release the remaining cash held in escrow to unrestricted cash for use by the Utility. The approval resulted in a $161 million reduction to the cash in escrow within the Restricted cash balance on the Consolidated Balance Sheets.

On September 2, 2016, the Utility's settlement became effective resolving, among other matters, the Utility's claim against the CAISO for $165 million, which includes receivables and interest. Additionally, the Utility agreed to release $66 million of cash from escrow to the California Power Exchange. The settlement resulted in a $231 million reduction to the Disputed claims and customer refunds balance on the Consolidated Balance Sheets.

At December 31, 2016 and December 31, 2015, respectively, the Consolidated Balance Sheets reflected $236 million and $454 million in net claims within Disputed claims and customer refunds. The cash held in escrow within Restricted cash was zero as of December 31, 2016 and $228 million as of December 31, 2015. 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, 2016:

	Power Purchase Agreements					
(in millions)	**Renewable Energy**	**Conventional Energy**	**Other**	**Natural Gas**	**Nuclear Fuel**	**Total**
2017	$ 2,233	$ 815	$ 369	$ 536	$ 97	$ 4,050
2018	2,108	716	284	169	93	3,370
2019	2,144	698	225	160	95	3,322
2020	2,139	677	179	148	130	3,273
2021	2,117	585	147	93	49	2,991
Thereafter	27,685	1,168	653	455	136	30,097
Total purchase commitments	**$ 38,426**	**$ 4,659**	**$ 1,857**	**$ 1,561**	**$ 600**	**$ 47,103**

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, 2016, renewable energy contracts expire at various dates between 2017 and 2043.

Conventional Energy Power Purchase Agreements. The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2016, these power purchase agreements expire at various dates between 2017 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, 2016 and 2015, net capital leases reflected in property, plant, and equipment on the Consolidated

Balance Sheets were $35 million and $54 million including accumulated amortization of $148 million and $147 million, respectively. The present value of the future minimum lease payments due under these agreements included $17 million and $19 million in Current Liabilities and $18 million and $35 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2016, QF contracts in operation expire at various dates between 2017 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 $3.5 billion in 2016, $3.5 billion in 2015, and $3.6 billion in 2014.

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 2017 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 $0.7 billion in 2016, $0.9 billion in 2015, and $1.4 billion in 2014.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2017 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 $100 million in 2016, $128 million in 2015, and $105 million in 2014.

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 2017 and 2052. At December 31, 2016, the future minimum payments related to these commitments were as follows:

(in millions)	Operating Leases
2017	$ 44
2018	41
2019	39
2020	39
2021	36
Thereafter	168
Total minimum lease payments	**$ 367**

Payments for other commitments related to operating leases amounted to $43 million in 2016, $41 million in 2015, and $42 million in 2014. 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 year.

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				4,743,591
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				845,082
3	Preceding Quarter/Year to Date Changes in Fair Value				(2,365,555)
4	Total (lines 2 and 3)				(1,520,473)
5	Balance of Account 219 at End of Preceding Quarter/Year				3,223,118
6	Balance of Account 219 at Beginning of Current Year				3,223,118
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				812,168
8	Current Quarter/Year to Date Changes in Fair Value				(1,602,029)
9	Total (lines 7 and 8)				(789,861)
10	Balance of Account 219 at End of Current Quarter/Year				2,433,257

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			4,743,591	[redacted]	
2			845,082		
3			(2,365,555)		
4			(1,520,473)	862,018,078	860,497,605
5			3,223,118	[redacted]	
6			3,223,118		
7			812,168		
8			(1,602,029)		
9			(789,861)	1,425,777,382	1,424,987,521
10			2,433,257	[redacted]	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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)	65,364,587,178	48,072,798,258
4	Property Under Capital Leases	201,744,692	183,513,971
5	Plant Purchased or Sold	-85,174	-219,416
6	Completed Construction not Classified	11,116,949,314	6,342,714,244
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	76,683,196,010	54,598,807,057
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,183,195,426	1,475,594,177
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	78,866,391,436	56,074,401,234
14	Accum Prov for Depr, Amort, & Depl	33,823,849,160	24,295,611,734
15	Net Utility Plant (13 less 14)	45,042,542,276	31,778,789,500
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	32,850,410,046	24,238,665,711
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	8,128,674	
21	Amort of Other Utility Plant	965,310,440	56,946,023
22	Total In Service (18 thru 21)	33,823,849,160	24,295,611,734
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)	33,823,849,160	24,295,611,734

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
11,377,685,934				5,914,102,986	3
				18,230,721	4
-308,266				442,508	5
4,279,255,270				494,979,800	6
					7
15,656,632,938				6,427,756,015	8
					9
					10
387,613,473				319,987,776	11
					12
16,044,246,411				6,747,743,791	13
7,006,743,069				2,521,494,357	14
9,037,503,342				4,226,249,434	15
					16
					17
6,995,262,516				1,616,481,819	18
					19
8,128,674					20
3,351,879				905,012,538	21
7,006,743,069				2,521,494,357	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
7,006,743,069				2,521,494,357	33

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	285,001,087	106,965,021
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	285,001,087	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	387,399,860	111,821,105
10	SUBTOTAL (Total 8 & 9)	387,399,860	
11	Spent Nuclear Fuel (120.4)	2,067,748,581	96,543,424
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,256,442,841	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	483,706,687	
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
	111,821,105	280,145,003	3
			4
			5
		280,145,003	6
			7
			8
	96,543,425	402,677,540	9
		402,677,540	10
		2,164,292,005	11
			12
-125,349,148		2,381,791,989	13
		465,322,559	14
			15
			16
			17
			18
			19
			20
			21
			22

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

Cost of fuel inserted into reactor during 2016; 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 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	03/31/2017	End of 2016/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	113,750,070	185,868
4	(303) Miscellaneous Intangible Plant	2,482,276	188,570
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	116,232,346	374,438
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,569,626	74,579
9	(311) Structures and Improvements	112,125,238	505,877
10	(312) Boiler Plant Equipment	273,493,692	859,753
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	248,783,088	7,617,714
13	(315) Accessory Electric Equipment	50,697,112	582,181
14	(316) Misc. Power Plant Equipment	28,295,578	
15	(317) Asset Retirement Costs for Steam Production	92,189,557	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	814,153,891	9,640,104
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	22,726,561	
19	(321) Structures and Improvements	1,036,743,265	14,013,192
20	(322) Reactor Plant Equipment	3,432,483,225	71,205,386
21	(323) Turbogenerator Units	1,162,811,054	4,259,922
22	(324) Accessory Electric Equipment	809,889,540	8,120,201
23	(325) Misc. Power Plant Equipment	1,056,048,489	80,629,264
24	(326) Asset Retirement Costs for Nuclear Production	1,313,483,579	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	8,834,185,713	178,227,965
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	42,341,270	554,646
28	(331) Structures and Improvements	428,436,303	49,381,330
29	(332) Reservoirs, Dams, and Waterways	1,950,666,720	65,875,152
30	(333) Water Wheels, Turbines, and Generators	787,328,072	89,621,218
31	(334) Accessory Electric Equipment	253,591,476	15,323,090
32	(335) Misc. Power PLant Equipment	87,237,591	6,798,023
33	(336) Roads, Railroads, and Bridges	73,152,870	6,786,133
34	(337) Asset Retirement Costs for Hydraulic Production	7,200,427	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	3,629,954,729	234,339,592
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,207,870	
38	(341) Structures and Improvements	210,375,654	
39	(342) Fuel Holders, Products, and Accessories	11,264,118	7,078
40	(343) Prime Movers	223,711,698	2,377,781
41	(344) Generators	353,570,941	-831
42	(345) Accessory Electric Equipment	210,675,562	1,151,189
43	(346) Misc. Power Plant Equipment	95,867,566	1,558,569
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,124,673,409	5,093,786
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	14,402,967,742	427,301,447

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	245,529,797	10,496,982
49	(352) Structures and Improvements	416,007,406	88,987,934
50	(353) Station Equipment	5,294,417,861	534,571,878
51	(354) Towers and Fixtures	786,169,055	48,836,084
52	(355) Poles and Fixtures	899,349,367	137,463,954
53	(356) Overhead Conductors and Devices	1,383,308,583	75,675,124
54	(357) Underground Conduit	351,257,648	147,246,200
55	(358) Underground Conductors and Devices	257,949,627	4,499,271
56	(359) Roads and Trails	63,834,858	8,274,723
57	(359.1) Asset Retirement Costs for Transmission Plant	2,833,074	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	9,700,657,276	1,056,052,150
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	177,057,427	1,039,554
61	(361) Structures and Improvements	314,904,461	8,970,903
62	(362) Station Equipment	3,000,119,351	215,140,368
63	(363) Storage Battery Equipment	32,814,645	284,889
64	(364) Poles, Towers, and Fixtures	3,730,312,156	228,414,029
65	(365) Overhead Conductors and Devices	4,289,653,220	258,066,287
66	(366) Underground Conduit	2,652,279,271	108,722,673
67	(367) Underground Conductors and Devices	4,095,109,752	233,950,599
68	(368) Line Transformers	2,916,391,575	277,334,337
69	(369) Services	3,011,526,435	117,659,964
70	(370) Meters	1,079,780,390	50,766,036
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	212,846,207	7,919,178
74	(374) Asset Retirement Costs for Distribution Plant	13,423,729	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	25,554,427,979	1,508,268,817
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	15,131,415	2,174,146
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	103,985,004	14,014,757
92	(395) Laboratory Equipment	14,403,679	516,676
93	(396) Power Operated Equipment	271,612	
94	(397) Communication Equipment	136,120,007	88,465,744
95	(398) Miscellaneous Equipment	57,686,155	1,011,164
96	SUBTOTAL (Enter Total of lines 86 thru 95)	339,277,367	106,182,487
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)	814,853,424	106,182,487
100	TOTAL (Accounts 101 and 106)	50,589,138,767	3,098,179,339
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)	100,000	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	50,589,038,767	3,098,179,339

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			113,935,938		3
			2,670,846		4
			116,606,784		5
					6
					7
			8,644,205		8
		-20,287	112,610,828		9
			274,353,445		10
					11
			256,400,802		12
			51,279,293		13
			28,295,578		14
			92,189,557		15
		-20,287	823,773,708		16
					17
			22,726,561		18
3,078,569			1,047,677,888		19
11,885,203			3,491,803,408		20
-527,352			1,167,598,328		21
2,007,240			816,002,501		22
14,718,958			1,121,958,795		23
	933,126,483		2,246,610,062		24
31,162,618	933,126,483		9,914,377,543		25
					26
		-966,849	41,929,067		27
2,412,465		-25,123	475,380,045		28
1,380,903		966,849	2,016,127,818		29
5,672,805			871,276,485		30
2,625,723			266,288,843		31
1,071,365		-401,685	92,562,564		32
410,874		-16,401	79,511,728		33
			7,200,427		34
13,574,135		-443,209	3,850,276,977		35
					36
			19,207,870		37
			210,375,654		38
			11,271,196		39
			226,089,479		40
			353,570,110		41
			211,826,751		42
			97,426,135		43
					44
			1,129,767,195		45
44,736,753	933,126,483	-463,496	15,718,195,423		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	03/31/2017	End of 2016/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
		1,228,513	257,255,292	48
		-57,140,948	447,854,392	49
32,232,816		77,539,649	5,874,296,572	50
246,303		757,757	835,516,593	51
1,988,804		-545,317	1,034,279,200	52
4,596,069		635,803	1,455,023,441	53
19,072		78,497	498,563,273	54
		5,534	262,454,432	55
51,699		893,547	72,951,429	56
			2,833,074	57
39,134,763		23,453,035	10,741,027,698	58
				59
		-544,019	177,552,962	60
65,602			323,809,762	61
20,321,892		-3,380,782	3,191,557,045	62
			33,099,534	63
15,505,280		-10,566,392	3,932,654,513	64
30,384,004		-1,830,302	4,515,505,201	65
65,197		-3,806	2,760,932,941	66
8,523,285	-139,402	-437	4,320,397,227	67
29,077,250		-36,418	3,164,612,244	68
455,236		-3,418	3,128,727,745	69
12,767,494	1,232,644		1,119,011,576	70
			27,313,912	71
			895,448	72
		-128	220,765,257	73
			13,423,729	74
117,165,240	1,093,242	-16,365,702	26,930,259,096	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			424,632	86
			11,254,863	87
980,428			16,325,133	88
				89
				90
		935,981	118,935,742	91
475,066			14,445,289	92
588			271,024	93
28,494		-7,720,584	216,836,673	94
3,706,203	218,927	144,045	55,354,088	95
5,190,779	218,927	-6,640,558	433,847,444	96
			468,499,422	97
			7,076,635	98
5,190,779	218,927	-6,640,558	909,423,501	99
206,227,535	934,438,652	-16,721	54,415,512,502	100
				101
	119,416		219,416	102
				103
206,227,535	934,319,236	-16,721	54,415,293,086	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	03/31/2017	End of 2016/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	68005100 Lead Order-License Renewal Application	39,834,257
2	7054908 MC-P Relic- Project Management	32,139,881
3	68001801 PLO-U1: Rpl Process Protection Sys (PPS)	23,671,511
4	7070913 DS conduct Rel studies	20,237,912
5	68016664 PLO-U1:NFPA 805 Hot Shutdown Panel Upgr	20,011,085
6	74001423 MISSOURI FLAT-GOLD HILL 115 KV - LINE	19,522,007
7	68011748 PLO-U2:Repl Main Generator Stator	17,902,670
8	74003355 61-CHRISTIE SUB: INSTALL BANK 2	15,070,804
9	68016662 PLO-U1:NFPA 805 Fire Detection Sys Upgr	14,823,849
10	7021725 UNFFR Relic Routine Project Management	13,433,453
11	74003962 64-MOSS LANDING 115 KV BUS TO BAAH	12,227,376
12	30968128 Q532 WHITNEY POINT SOLAR SW STATION MPAC	11,859,978
13	74003241 MARTIN-EMBARCADERO #2 (HZ-2) 230KV RELOC	11,752,228
14	31035789 EMBARCADERO (SF-Z) DECOUPLE BKS 1, 3, 5	11,329,457
15	68018981 PLO-CRVS Design Vulnerability	11,308,092
16	31055804 OCGC Q679 BURFORD GIFFEN-GIFFEN SUB BUS	11,295,459
17	74000925 MIDWAY ANDREW_CPUC LIC/PER	11,035,898
18	74001857 EL CERRITO G: 115KV BUS UPGRADE PHASE 1	10,879,123
19	13004820 Drum Spaulding - Developing PAD and NOI	10,388,190
20	68001812 PLO-U2: Rpl Process Protection Sys (PPS)	9,892,758
21	7026033 UNFFR Relic Aquatic Resource Stdy	9,878,062
22	68038982 PLO: Security Defensive Strategy Upgrade	9,777,608
23	74000996 67-OLEUM PP - INSTALL 115 KV MPAC	9,268,769
24	74000924 ESTRELLA_CPUC LIC/PER	9,151,769
25	74001924 67-MARTINEZ PP: 115 KV MPAC	8,996,543
26	30992248 GREATER BAY AREA RESTORATION PLAN (SF)	8,848,759
27	74001422 MISSOURI FLAT-GOLD HILL 60KV LINE UPGRAD	8,810,211
28	30901921 RIO OSO-W SACRAMENTO 115KV NERC	8,518,105
29	13003982 DS-C Relic- Cond studies for all RA	8,517,659
30	74001039 LARKIN: REPL 12KV SWGR	8,342,993
31	30822460 SF RAS A: REPLACE SYSTEM AT SFGO	8,185,713
32	74000939 WRJ NONCOMPETITIVE_CPUC LIC/PER	8,020,691
33	74000907 PIT 4 U2 REPLACE RUNNER	7,701,053
34	30766763 NV_67-KASSON SUB: 115/60KV MPAC	7,397,315
35	68036564 PLO- Upgrd Bldg 113 Phase II	7,212,014
36	74000857 SPRING NONCOMPETITIVE_CPUC LIC/PER	6,739,511
37	7017646 Poe Relic - Prepare Exhibit E	6,675,623
38	7076869 Buck Rel Studies	6,525,534
39	31017525 MARTIN SUB: REPL 12KV BUS G W/VACUM SWGR	6,468,731
40	30877693 NV_67 - PANOCHE 115KV MPAC	6,279,275
41	68032509 PLO: COM: Procure Casks-Load Campaign #7	6,255,500
42	7011106 Poe Relic - Project Management	6,233,814
43	TOTAL	1,475,594,177

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	74001843 46-REPLACE MENLO BANK #1 (CONSTR 2016)	6,163,393
2	74001445 Belden Generator Rewind	6,144,769
3	31103714 SYNCHROPHASOR DEMONSTRATION	6,109,269
4	68014363 U1 SFP Bridge Crane Upgrades	5,882,072
5	74002282 LERDO 115KVB BUS RELIABILITY IMPROVEMENT	5,739,621
6	74000933 LOCKEFORD-LODI_CPUC LIC/PER	5,696,905
7	74002346 NV_PEASE-MARYSVILLE 60KV L CONV MVILL SU	5,562,584
8	74001063 GATE-GREGG 230KV T-LINE CPUC LIC/PER	5,493,309
9	74000989 NC_WILDWOOD SUB - REPLACE BANKS 1 & 1A	5,412,359
10	31114967 NEWARK SUB: TECH_SECURITY UPGRADE	5,341,260
11	7026032 UNFFR Relic Water Use & Qlty Stdy	5,328,295
12	30676931 R2 2017 BELMONT AVE FRESNO R20A	5,320,320
13	74001604 NC_WINDSOR-NEW BANK & SWITCHGEAR INSTALL	5,221,738
14	31168841 FAA 2016 PROGRAM	5,138,422
15	7026037 UNFFR Relic Land Use/Mgt Study	5,102,156
16	74001118 SAN BERNARD-TEJON LINE RECONDUCTORING	4,953,934
17	7058680 Permit Holdover Project - Distribution	4,934,187
18	7055507 DS Relic- Strategic Planning	4,931,239
19	30895387 METCALF-MOSS LANDING #1 & #2 230KV NERC	4,868,572
20	13005520 Kilarc Cow Decom Project Management	4,822,644
21	74001249 NV_MANTECA BANK 3	4,772,007
22	74001391 60-SOUTH OF PALERMO REINFORCEMENT (PH-1)	4,710,920
23	30945907 DONNELLS-CURTIS 115KV NERC	4,662,127
24	68027382 PLO-COM:TS Setpoint Calcs Rev & Reloc	4,652,667
25	74000901 MARTIN BUS EXTENSION_CPUC LIC/PER	4,575,739
26	7055646 DS Relic- Project Management	4,555,708
27	74000600 FULTON-FITCH MTN. RECOND 60KV LN	4,429,060
28	68014364 U2 SFP Bridge Crane Upgrades	4,374,226
29	31165126 NC_ALLEGHANY BANK 1 REPLACEMENT	4,276,371
30	74001853 EL CERRITO G: REPL BK 4 115-12KV, 60MVA,	4,265,612
31	74003961 67-MOSS LANDING 115 KV AUTO - MPAC	4,243,926
32	68046400 PLO: U1: REPL BAFFLE BOLTS	4,174,084
33	31168685 ETTM CENTRAL PARK WEST	4,110,327
34	31022241 PIT #5-ROUND MTN #1 230KV NERC PROJECT	3,994,056
35	74001713 HUNTERS POINT: 115KV GIS BAAH	3,867,741
36	68020200 PLO: U2: REPL CFCU CLNG COILS (2R20) 2-5	3,784,650
37	74001439 EP C3C4DNU: COALINGA1-COAL.2 70KV TORNAD	3,770,784
38	31021691 PIT #5-ROUND MTN #2 230KV NERC PROJECT	3,764,685
39	31084234 2016 AIRWAYS 1108 NEW FEEDER	3,760,974
40	74001904 GREEN VALLEY:115 KV BAAH PHASE 1	3,683,009
41	74003087 93-SALINAS #1 AND #2 REPL LSP W/ TSP	3,634,407
42	74000706 BRIGHTON-DAVIS 115KV NERC STEEL	3,588,014
43	TOTAL	1,475,594,177

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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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	13018731 Haas U2 Repl Cooling Water System	3,568,069
2	74001105 SOBRANTE REPL BK 2 (230-115KV, 420 MVA)	3,548,105
3	31031900 Q829 PANOCHE TLINE (NU)	3,543,366
4	74000937 ORO LOMA_CPUC LIC/PER	3,452,009
5	68044198 PLO: COM: Upgrd Bldg 260-264	3,380,632
6	74001056 NC_NORTH TOWER: EMG RPL BK 3 & 2	3,374,589
7	31186691 UPGRADE SUSTAINMENT	3,369,580
8	68016640 PLO-U1:Replace Cavity Seals	3,337,355
9	68015242 PLO-COM::Rplc Secondary Chem Lab	3,324,249
10	30797619 OAKLEY GENERATING STN: LAS POSITAS-NEWAR	3,305,177
11	68012041 PLO-U1:Replace U1 FLUR/SLUR Relays	3,296,462
12	7069447 Develop & File Lic. Surrender App.	3,282,916
13	74008406 Q632B San Joaquin 1A Crescent SS	3,279,533
14	13006580 Merced Falls "Routine Project Management"	3,255,685
15	7049829 DC Relic Begin Prep of NOI and PAD	3,253,857
16	68029480 PLO-U1:Instl 230kV Open Ckt Fault Prot	3,223,855
17	31122680 IGNACIO-SAN RAFAEL 3 115KV NERC PH 2	3,196,280
18	30761606 NC_IGNACIO/ ALTO- 60 KV LINE W/ CB	3,189,320
19	7072819 Helms - Replace Liquid Rheostat	3,112,925
20	13018727 Haas U2 Replace Governor	3,091,699
21	30763887 60-GREEN VALLEY-WATSONVILLE 60KV-115KV	3,067,182
22	30950804 WOODLEAF PALERMO NERC PROJ	3,032,679
23	68015281 PLO-U2:Repl Cavity Seal with Permnt Seal	3,002,743
24	74001967 INSTALL SCADA BAKERSFIELD 09	2,975,592
25	7053945 DC Relic - Prepare Study Plans	2,939,134
26	31028310 MORAGA SUB: PHYSICAL SECURITY UPGRADE	2,917,457
27	74001825 Tiger Creek Canal 2016/2017 Liner	2,913,725
28	68039380 PLO: Integrated Video Mgmt Sys Upgrade	2,830,514
29	7026034 UNFFR Relic Terres Resources Stdy	2,766,269
30	68031962 PLO- COM: Simulator Upgrade Phase V	2,756,807
31	7043247 RCC Lic Imp Cold Water Feasibility Study	2,687,809
32	74001688 NC_(DA-ABB) MAPLE CREEK SUB:REACTIVE SUP	2,672,602
33	13006140 MC-P Relic- Conduct Relicensing Studies	2,631,078
34	30989151 GREATER BAY AREA RESTORATION PLAN (OAK)	2,602,859
35	74004835 54-SF K SUB: REMOVE UNIT SUBS 3 & 4	2,560,024
36	31021682 OLEUM-"G" #1 NERC PROJECT	2,536,064
37	74001278 WILSON-ORO LOMA - NERC PROJECT	2,514,504
38	7054909 MC-P Relic- Prepare NOI and PAD	2,500,230
39	7017635 Poe Relic Field Study/Aquatic Res	2,499,994
40	30616019 ED WRO-EASTSIDE ROAD POTTER VALLEY	2,463,864
41	31031715 Q829 LAS AGUILLAS SWITCHING STATION (NU	2,448,745
42	13002402 DS-C Relic- Conduct Pre-App Proj Man	2,446,314
43	TOTAL	1,475,594,177

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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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	30827391 R6 OLD CNTY RD BELMONT PH1 R20A	2,442,310
2	13015400 Helms - Main Crane Modifications	2,439,311
3	30842587 OAKLEY GENERATING STN:COCOPP-DELTA PUMPS	2,423,395
4	68014444 PLO-U1:Replace Main Gen Output Breaker	2,388,684
5	68018677 Support 02*998 PPS (EAGLE 21) PARTS U2	2,384,553
6	74001175 (DA-B&V) MOSHER-LOCKFORD 60KV RECOND.	2,384,491
7	74001177 NV_EPC_STOCKTON A DISTRIBUTION SCADA	2,379,529
8	74000949 NORTHERN FRESNO_CPUC LIC/PER	2,379,304
9	74002445 GATES BAAH #2 500/230 KV	2,378,689
10	74001710 94-SANGER SUB: 115KV BUS REPLACEMENT	2,308,941
11	74001781 NV_RIO OSO SUB BANKS #1 & #2	2,301,267
12	74001432 COTTNWD-RED BLUFF - RECONDUCTOR	2,282,144
13	74001064 GATES-GREGG PRE-BID COSTS	2,262,893
14	74001436 (DA-B&M) ELECTRA-VALLEY SPRGS CAP/RECOND	2,258,810
15	7021727 UNFFR Relic Prepare 5 Year Library	2,239,441
16	74001059 Pit 5 Repl Transformer-B1ABC & B2ABCSP	2,195,393
17	68020110 PLO: U1: REPL CFCU CLNG COILS (1R20) 1-5	2,193,552
18	74002057 CLOVIS SUB REPL 115KV CB 132, 142	2,147,132
19	30940862 EL DORADO-MISSOURI FLAT #1 NERC PRJ	2,134,728
20	74001248 NV_INSTALL LE GRAND BANK 2	2,132,352
21	13009582 Helms - Replace T1 Gate Controls	2,122,692
22	74000966 MIDWAY 230KV BUS DIFFERENTIAL PROJECT	2,107,890
23	13011860 Pit 6 Replace Trash Rake	2,099,503
24	13009580 DeSabla Replace Governor	2,072,742
25	7026036 UNFFR Relic Rec Resources Study	2,028,620
26	30992521 NICWILKSLO SET 35 POLE OPERATIVE	2,008,743
27	74004015 SAN MATEO BANK 4 REPLACEMENT	2,002,900
28	68036566 PLO- Upgrd Bldg 116 Entire 2nd Floor	1,998,844
29	74001737 BAFB TO WHEATLAND #2 60KV POLE RPL	1,977,513
30	74004971 NC_TABLE MTN: REPL SCB 1&2 CONTROLLER	1,970,894
31	74001782 NV_RIO OSO SUB 115KV BAAH/GIS	1,965,750
32	7060966 COM:Instl Bar Rack Rake System	1,947,588
33	74000936 WRJ COMPETITIVE_CPUC LIC/PER	1,933,548
34	68006140 Lead Order-U2:Repl FLURs/SLURs	1,925,062
35	74001780 NV_RIO OSO SUB 230KV BAAH/GIS	1,913,133
36	31010914 FULTON-IGNACIO #1 230KV NERC	1,892,008
37	30993229 MIDWAY-TAFT NERC PROJECT	1,878,477
38	74001102 SAN FRAN M SUB: BK2-REPL 12KV & 4KV SWGR	1,872,493
39	74001600 ANTIOCH CUTOVER 4KV TO 21KV & DEMO SUB	1,853,291
40	74001487 JEFFERSON-MARTIN 230 KV RELOC @ CRYSTAL	1,852,234
41	74001602 NC_WINDSOR SUB: RING BUS INSTALLATION	1,845,466
42	13008740 Battle Crk - Phase 2 License Amendment	1,831,323
43	TOTAL	1,475,594,177

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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	31256755 SUPPORT CENTER TRAINING ROOM	1,812,930
2	68045305 U1: Rod Cntrl Cards - Early Order	1,812,653
3	74007840 Helms - Replace HPCO HPU	1,797,791
4	74004680 NV_VACA DIXON SUB:230KV ENV COMP MITIGAT	1,796,169
5	13018728 Kerckhoff 1 - Retire Unit 2	1,793,268
6	31158648 ORIOLE EMERGENCY REPLACEMENT CB 401	1,785,266
7	13019647 DeSabla SC Modernization and Compliance	1,760,027
8	74000856 SPRING COMPETITIVE_CPUC LIC/PER	1,748,833
9	74004000 NC_FAIRHAVEN: REPLACE 60KV	1,744,164
10	30933202 CORTINA #1 60KV NERC PRJ (120 LOCS)	1,730,567
11	74004964 SOBRANTE: ADD & REPL 14-115KV BKERS P2	1,725,553
12	74001179 NV_94-INDIAN FLAT SUB:REPL SW 17 W/1-70K	1,697,756
13	68014544 PLO-Bar Racks Cathodic Protection Sys	1,689,370
14	7026029 UNFFR Relic Prep 1st Stage Consult Pkg	1,687,117
15	31080050 2016 WOODWARD DPA CAP INCR	1,682,383
16	7086449 IT for base camps	1,681,138
17	74006883 ENHANCED VOLTAGE STABILITY ASSESSMENT	1,666,462
18	68019301 U1:Upgrade Polisher Computer Workstation	1,665,923
19	74005362 HENRIETTA TRANSFORMER BANK 1 EMERGENCY R	1,634,007
20	74001424 NV_61-MF-GH 115KV - GOLDHILL SUB	1,622,550
21	30985234 KERCKHOFF #1-KERCKHOFF #2 NERC PROJECT	1,617,474
22	74000822 COOLEY - PALO ALTO: REBUILD 115KV LINE	1,615,066
23	30853685 67-INSTALL SCADA @ SEMITROPIC	1,610,124
24	74001772 60-EVERGREEN-MABURY 60KV-115KV CONVERT	1,606,088
25	68012135 PLO-U1 Instl ICW HdTk N2 Cover Gas	1,593,920
26	30913996 NV_09-TRACY: INSTALL D-SCADA ON 4 BANKS	1,592,366
27	74004406 EP C3C4DNU: RECON KRN TEVIS LAMT 115KV J	1,585,184
28	74002053 RIO BRAVO: INSTALL SCADA ON CB 122, 112,	1,576,004
29	74001469 NC_67 - RM: MALIN - ROUND MTN #1 500KV	1,533,899
30	74000709 HUMBOLDT BAY RECONDUCTOR PROJECT	1,528,788
31	74001222 RAVENSWOOD: INSTALL SCADA	1,523,417
32	74001162 GARBRVLLE-LAYTNVLLE PHASE 2 SEG 4	1,521,195
33	30899980 R2Z FIRST ST PH2 LOS ALTOS R20A	1,511,611
34	31168789 ETTM LAMPLIGHTER MHP	1,511,608
35	30968125 Q532 WHITNEY POINT SOLAR SCHINDLER DTT-S	1,507,987
36	74000602 CARIBOU#2 GRAYS FLAT TO SPANISH CREEK	1,507,007
37	74008620 Fordyce Dam Leakage Reduction	1,504,250
38	74005711 EM_OAKLAND K SUB - REPL. CB 332	1,499,518
39	30937193 R2Z STANLEY BLVD PLEASANTON R20A	1,475,626
40	68038260 PLO-COM: North Access Rd Upgrade	1,475,471
41	74001580 OAKLAND C REPL BANK #3	1,467,273
42	74007802 Halsey Afterbay Trash Rack	1,466,753
43	TOTAL	1,475,594,177

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	13002403 DS-C Relic- Conduct Studies	1,465,011
2	31178945 EP 2016 LINCOLN 2109 CAPAC PROJ - PH2	1,457,051
3	30891710 Q526 PAIGE SOLAR T-LINE (NU)	1,450,783
4	31168692 ETTM ALMOND GROVE MHP	1,450,190
5	68034341 PLO:COM Repl MSLB 4kV Switchgear Louvers	1,445,172
6	30977258 LAKEVIEW SUB - REPLACE CBS 22, 32	1,433,608
7	31168792 ETTM MOON VALLEY MHP	1,414,263
8	30891707 Q532 WHITNEY POINT SOLAR TLINE (NU)	1,413,647
9	31079024 EP LINCOLN 2109 FEEDER Y2016_06H PH 1	1,408,092
10	68029481 PLO-U2:Instl 230kV Open Ckt Fault Prot	1,402,123
11	31022243 PIT #7 TAP 230KV NERC PROJECT	1,401,356
12	7062249 MC-P- Proj Scoping and Study Plan Devp	1,395,716
13	68019124 PLO-Com:Repl Breathing Air Compsr Ph II	1,395,150
14	7049828 DC Relic Project Management	1,394,967
15	30651126 67-INSTALL FIRE PROTECTION CONTROLS-MPAC	1,393,771
16	7070917 DS Post App filing activities	1,392,592
17	74001792 COLEMAN-RED BLUFF_CPUC LIC/PER	1,379,998
18	74001058 Pit 6 Replace Spillway Apron	1,366,602
19	74000853 UPGRADE RIO OSO 230KV SUBSTATION	1,351,159
20	74000988 48-CASTRO VALLEY: REPL 12KV SWITCHGEAR	1,350,041
21	13011921 NFSL Additional Design Imp	1,343,131
22	13006781 DeSabla-Centerville Proj Mgmt Post LA	1,343,010
23	74000710 EEL RIVER: INSTALL 2-60KV SCADA SW.17 &	1,337,668
24	13020040 2017 Hydro Waterways Safety Shasta	1,327,075
25	7017638 Poe Relic Field Study/Recreation	1,314,204
26	68032804 PLO- COM: Tornado Missile LAR	1,310,690
27	31168761 ETTM SOUTH BAY MHP	1,309,226
28	31023003 2016 GUERNSEY 1103-PITMN FRMS CAP	1,308,902
29	31168762 ETTM SILVER CREEK MOBILE ESTATES II	1,304,049
30	31168727 ETTM FAIRGROUNDS MOBILE ESTATES	1,289,822
31	30707866 R4E HWY 84 WRO RUBY HILL 60KV RELOC	1,289,475
32	68029724 U1: Control Room Condenser Replacement	1,284,543
33	68012133 PLO-U1: Instl SCW HdTk N2 Cover Gas	1,280,143
34	30987099 CARMEL REARYARD CABLE REPL - PHASE 2	1,272,724
35	68008644 Lead Order-U2 FHB Supply Fan Replace	1,259,616
36	7055645 DS Relic- Coord Study w/ NID	1,253,331
37	31073803 TGRAM SF 2016 NETWORK Y3, 8 TGRAMS	1,246,040
38	74000841 HERNDON-KEARNEY 230 KV LINE RECONDUCTOR	1,240,793
39	74001112 RIPON SUB: BUILD 2ND 115 KV	1,236,217
40	68017320 PLO-Repl Oily Water Separator System	1,231,183
41	74001940 WESTPARK SUB: INSTALL SWITCH BK2	1,215,783
42	68036571 PLO- Upgrd Bldg 102 Entire 2nd Floor	1,212,916
43	TOTAL	1,475,594,177

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	31059220 Q705 FRONTIER BLACKWELL TLINE (NU)	1,207,661
2	74001801 NV_SERIES REAC@WARNERVILLE-WILSON 230KV	1,198,079
3	68000145 Lead Order-U1:Repl Boric Acid Xfer Pumps	1,196,679
4	74001468 NC_67 - MALIN - ROUND MTN #2 500KV	1,195,866
5	74000707 60 KINGSBURG-LEMOORE 70KV RECOND. PH1	1,191,685
6	74001588 NV_67-ORO LOMA: INSTALL 115 KV MPAC	1,188,225
7	31212345 SPRING GAP SUB INSTALL CB 1702	1,188,152
8	74000990 64-CHRISTIE CB 32 & 72 REPLACEMENT PROJ	1,180,201
9	74004101 EM_CASTRO VALLEY - INSTALL BART BANK CB	1,177,032
10	31168861 EP 506 OAK RD STANFORD	1,173,175
11	31017556 PIT #3-PIT #1 230KV NERC PROJECT	1,169,491
12	30913917 SPSI RIO BRAVO: INSTALL SCADA ON CB 122,	1,154,239
13	74006423 NC_ROUND MTN: REPL SCB 2 CONTROLLER	1,150,021
14	30760432 LARKIN SUB_CPMC NEW CKT_CAPACITY	1,147,881
15	74001302 NC_ESSEX JUNCT SUB-REPL 60KV CB 52E	1,145,505
16	74003980 NC_ROUND MTN: REPL SCB 1 CONTROLLER	1,143,720
17	74006422 NEWARK SUB: SVC CONTROLLER UPDATE	1,138,020
18	13011869 Pit 6 Replace Stoplog Lifting Device	1,135,406
19	31051909 NC_CEDAR CREEK: INSTALL D-SCADA	1,133,470
20	74000731 EAST SHORE-OAKLAND J 115KV RECONDUCT(TL)	1,133,134
21	74001785 NV_RIO OSO SUB 230KV MPAC	1,127,892
22	74000662 NC_VALLEJO B: REPL. 4KV SWGR & BANKS	1,115,014
23	13011870 Pit 7 Replace Stoplog Lifting Device	1,109,980
24	68012920 PLO-U1:Add Iso Vlvs SI Test Hdr Phase II	1,105,362
25	7088133 Retrofit Newark Substation	1,097,029
26	31232087 CARIBOU-WESTWOOD ROW RELIABILIYT	1,094,326
27	74002343 NV_ATHENS SUBSTATION PURCHASE	1,088,762
28	74001223 REDWOOD CITY-REPL CB 404,406,408,409,410	1,081,340
29	74008385 Coleman Decommission Asbury Pipe	1,079,196
30	13018558 Bucks Cr Install Penst Protection System	1,076,916
31	68036981 PLO: COM: 500kv Road Upgrade	1,076,490
32	68041685 PLO:Mnge: Instl Cyber Sec Event Mgmt Sys	1,072,350
33	68041684 COM: Repl EXPLOSIVE DETECT/ITEMISER	1,062,749
34	31111507 FULTON-PUEBLO NERC (PH 2) :3/0 TO :16/7	1,059,765
35	68010300 U1:Replace 12kv Protection Relays	1,058,197
36	31160902 EP MORAGA RD MORAGA R20A	1,053,068
37	74001461 Strawberry Dam-Repair Concrete Face 2016	1,040,294
38	74001440 Tiger Creek U1 Rewind Generator	1,038,019
39	30765515 IGNACIO-MARE ISLAND 1000FT BDWALK	1,035,147
40	31020980 NC_FULTON INSTALL T SCADA	1,033,613
41	74001295 RAVENSWOOD-SAN MATEO 115KV NERC	1,031,512
42	31112685 CYMRIC SUB, 67-MRTU	1,029,439
43	TOTAL	1,475,594,177

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	74001858 EL CERRITO G: REPL 12KV CBS W/SWGR	1,028,914
2	74001641 R4= HIDDENBROOKE BACKTIE	1,024,556
3	30970621 PARADISE-TABLE MTN 115KV NERC STEEL	1,013,693
4	30848752 MONTA VISTA SUB - SPCC IMPROVEMENT	1,010,130
5	7073485 Salmon HEA Other Costs PG&E	1,006,078
6	68000146 Lead Order-U2:Repl Boric Acid Xfer Pumps	1,001,003
7	74001334 TEMBLOR-SAN LUIS OBISPO 115KV NERC	1,000,863
8	See footnote for description.	379,309,582
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43	TOTAL	1,475,594,177

Schedule Page: 216.7 Line No.: 8 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.

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	22,960,835,100	22,960,835,100		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,844,735,417	1,844,735,417		
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	Reserve Common Allocation	-149,240,876	-149,240,876		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,695,494,541	1,695,494,541		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	206,227,535	206,227,535		
13	Cost of Removal	174,068,838	174,068,838		
14	Salvage (Credit)	6,116,084	6,116,084		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	374,180,289	374,180,289		
16	Other Debit or Cr. Items (Describe, details in footnote):	-43,483,641	-43,483,641		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	24,238,665,711	24,238,665,711		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	383,693,632	383,693,632		
21	Nuclear Production	6,295,982,089	6,295,982,089		
22	Hydraulic Production-Conventional	1,321,444,650	1,321,444,650		
23	Hydraulic Production-Pumped Storage	754,927,844	754,927,844		
24	Other Production	233,891,739	233,891,739		
25	Transmission	2,818,898,517	2,818,898,517		
26	Distribution	11,889,365,919	11,889,365,919		
27	Regional Transmission and Market Operation				
28	General	540,461,321	540,461,321		
29	TOTAL (Enter Total of lines 20 thru 28)	24,238,665,711	24,238,665,711		

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	206,227,535
Book cost of plant retired, pages 204-209, column (d)	206,227,535
	0

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

Other Debit or Cr. Items:

FAS 143 Assets Depreciation (Nuclear & Fossil)	55,115,858
Decommissioning reclass to Regulatory Liability (Nuclear & Fossil)	(104,084,126)
FIN 47 Asset Depreciation (EDP, EHP, ETP, EGP)	857,576
Capital Lease Obligations	2,517,502
Mirant Adjustment	2,361,833
Gain/Loss	(87,731)
Reserve Adjustment	(164,553)
	(43,483,641)

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Eureka Energy Company			
2	Common Stock	1978		1,000
3	Additional Paid in Capital			3,248,680
4	Undistributed Earnings			97,937
5				
6	SUBTOTAL			3,347,617
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			3,222,139
18	Undistributed Earnings			-3,997,962
19				
20	SUBTOTAL			-765,823
21				
22	Standard Pacific Gas Line Incorporated			
23	Common Stock	1930-32		1,200
24	Additional Paid in Capital	1954		31,136,050
25	Undistributed Earnings			-25,568,190
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			29,887,236
35				
36	Midway Power LLC			
37	Additional Paid in Capital	2008		25,978,750
38	Undistributed Earnings			-18,295,162
39				
40	SUBTOTAL			7,683,588
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	40,152,618

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PG&E Real Estate			
2	Additional Paid in Capital	2010		-863,584
3	Undistributed Earnings			863,584
4				
5	SUBTOTAL			
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40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	40,152,618

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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
		3,643,552		3
-17,871		80,066		4
				5
-17,871		3,724,618		6
				7
				8
		100,000		9
		3,037,432		10
		-3,137,432		11
				12
				13
				14
				15
		10,000		16
		4,392,056		17
151,517		-4,421,943		18
				19
151,517		-19,887		20
				21
				22
		1,200		23
		39,953,917		24
-35,282		-26,293,373		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
-35,282		37,979,920		34
				35
				36
		26,027,928		37
-49,272		-18,344,434		38
				39
-49,272		7,683,494		40
				41
49,092		49,368,145		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	03/31/2017	End of 2016/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
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49,092		49,368,145		42

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)	1,004,654	1,429,732	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)	83,875,275	92,981,614	ALL
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	110,797,229	121,888,519	ALL
8	Transmission Plant (Estimated)	19,026,480	32,145,308	ALL
9	Distribution Plant (Estimated)	98,859,942	99,478,067	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)	312,558,926	346,493,508	
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)	313,563,580	347,923,240	

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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	102,131.00		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		13,860.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	88,271.00		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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2018		2019		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
42.00		42.00		387,996.00		504,071.00		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
						13,860.00		20
								21
								22
								23
								24
								25
								26
								27
								28
42.00		42.00		401,856.00		504,071.00		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
							13	44
							13	45
								46

Schedule Page: 228 Line No.: 29 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line item on page 110. Difference is due to approximately $403,540,000 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately $430,000 in alternative fuel vehicle credits.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2017 No. (d)	2017 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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
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								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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	03/31/2017	End of 2016/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21	Santa Cruz 115kV Reinforcement	3,800,000				3,800,000
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				3,800,000

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)	5,188,727	186	(5,204,059)	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)	634,983	186	(926,882)	186
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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

Order	Order Description	BALANCE 12/31/2015	COSTS INCURRED PERIOD ENDED 12/31/2016	REIMBURSEMENTS RECEIVED PERIOD ENDED 12/31/2016	NET ACTIVITY PERIOD ENDED 12/31/2016	BALANCE 12/31/2016
9718826	WL - BART Gridley 2 Solar -- SIS	4,730		-4,730	-4,730	
9718922	WG - USE - Cluster Analysis		92,460		92,460	92,460
9719582	WG Gradient Resources Project SIS	22,884				22,884
9719800	WAPA O'Neill Substation - System Impact			4,623	4,623	4,623
9719900	WG - BURNS&MCDONNELL-Cluster work	32,401	35,618		35,618	68,019
9720361	WG - CLUSTER 5 PROJECTS - PHASE 2	7,008	-8,059		-8,059	-1,051
9720841	Port of Stockton Solar- System Impact S	-5,914		5,914	5,914	
9721940	West Stanislaus ID Facility Study	-45,116		45,116	45,116	
9722202	WG - C6 - Cluster 6 Phase 2	24,434				24,434
9722840	WG - C7P1 - Cluster 7 Phase 1	-0				-0
9723600	CDWR BDCP-CM1 System Impact Study	6,050		-6,050	-6,050	
9723860	WG - 2015 Reassessment	-0				-0
9724040	KMPUD Load Interconnection Study	-48,707	36,900		36,900	-11,807
9724060	WG-MMA-Q557-White River West - Storage	27,833		-27,833	-27,833	0
9724281	WG - ISP - WGP Geysers	34,632	6,720	-41,480	-34,760	-129
9724300	Ntwrk Eval for Calpine 115kV Geysers Gen	-17,126	4,916		4,916	-12,209
9724301	MercedID Plan B System Impact Study	11,546		-11,546	-11,546	
9724401	WG - Q472 Post COD Modification	14,449		-14,449	-14,449	
9724560	WG ISP Woodland Battery	54,918	1,616	-56,534	-54,918	
9724820	WG - MMA # Q1038 # Pandora Solar	2,342		-2,342	-2,342	
9724880	WG - C7P2 - Cluster 7 Phase 2	425,953	45,389	-471,342	-425,953	-0
9724960	WG - C8 - SM - WGP Geysers	6,848	-6,848		-6,848	
9724961	WG - C8 - SM - New Kearney Energy Park	-203	203		203	
9724923	WG - C8P1 - Cluster 8 Phase 1	679,371	456,627	-1,138,262	-681,635	-2,264
9724930	WG - C8 - SM - Midtown Park ES	-99				-99
9725006	WG - C8 - SM - Alpaugh3BESS	-208	336		336	128
9725007	WG - C8 - SM - AmericanKings2	-208	336		336	128
9725008	WG - C8 - SM - AtwellWestBESS	-208	336		336	128
9725009	WG - C8 - SM - Britain	-208	336		336	128
9725010	WG - C8 - SM - CabrilloWind	-62	336		336	274
9725011	WG - C8 - SM - Corcoran2BESS	-386	336		336	-50
9725012	WG - C8 - SM # Trafalgar	-194	194		194	
9725013	WG - C8 - SM # Troy	-208	208		208	
9725014	WG - C8 - SM - WhiteRiverBESS	-208	336		336	128
9725000	WG - C8 - SM - Carneras Solar 1	-208	336		336	128
9725001	WG - C8 - SM - Gale Solar 1	-16	16		16	
9725002	WG - C8 - SM - Quail Creek Solar 1	-208	336		336	128
9725003	WG - C8 - SM - Seneca Solar 1	-208	336		336	128
9725083	WG - C8 - SM -WestlandsAlmond	-167	336		336	168
9725084	WG - C8 - SM -WestlandsApricot	-194	336		336	142
9725085	WG - C8 - SM -WestlandsArtichoke	-194	336		336	142
9725086	WG - C8 - SM -AlamoSprings	644	336		336	980
9725087	WG - C8 - SM -AlgosoES	644	336		336	980
9725088	WG - C8 - SM #Bridgehead	-336	336		336	
9725089	WG - C8 - SM #Brisbane	16	336		336	351
9725090	WG - C8 - SM -CentralValleyProject	172	336		336	508
9725091	WG - C8 - SM -CSICENTRAL40	-336	336		336	
9725092	WG - C8 - SM -DosAmigosSolar	-336	336		336	
9725093	WG - C8 - SM -FirebaughPanocheBESS	-336	336		336	
9725095	WG - C8 - SM -FresnoSolar1	337	336		336	673
9725096	WG - C8 - SM -GoldenEyeEnergyStorageCent	-336	336		336	
9725097	WG - C8 - SM -MolinoES	-336	336		336	
9725098	WG - C8 - SM -Montezuma 3	-336	336		336	
9725099	WG - C8 - SM -NicolausStorage	-336	336		336	
9725100	WG - C8 - SM -NorthCentralValley	-336	336		336	
9725101	WG - C8 - SM -OldKearneyES	31	336		336	366
9725102	WG - C8 - SM -Periwinkle	644	336		336	980
9725103	WG - C8 - SM -PointArenaES	644	336		336	980
9725104	WG - C8 - SM -SantaMariaEnergyReliabilit	55	336		336	391
9725105	WG - C8 - SM -ShingleSpringsES	-336	509		509	173
9725106	WG - C8 - SM -WestlandsSolarBlue	-208	336		336	128
9725107	WG - C8 - SM #WheelerIndigo	-336	336		336	
9725108	WG - C8 - SM -WhiteWolfSolar	-336	336		336	
9725040	WG - C8 - SM - AnchoCreekSolar	-208	336		336	128
9725041	WG - C8 - SM # BasketRidgeSolar	-251	251		251	

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) 03/31/2017	2016/Q4

FOOTNOTE DATA

9725042	WG - C8 - SM # BearCanyonEnergyStorage	644	336		336	980
9725043	WG - C8 - SM - KimberlinaSolar	664	-664		-664	
9725044	WG - C8 - SM - LunaValleySolar	-336	336		336	
9725045	WG - C8 - SM - MountVernonSolar	337	336		336	673
9725046	WG - C8 - SM - OvejaSolarFarm	644	336		336	980
9725047	WG - C8 - SM - WhiterockSolar	644	336		336	980
9725049	WG - C8 - SM -AquamarineWestside	-208	336		336	128
9725050	WG - C8 - SM -BeltranSolar_Updated	-336	336		336	
9725051	WG - C8 - SM -CornwallEnergyStorage	-336	336		336	
9725052	WG - C8 - SM #Creek	1,000	-1,000		-1,000	
9725053	WG - C8 - SM -HenriettaEnergyStorage	-102	336		336	234
9725054	WG - C8 - SM -MaricopaWestSolarPV3	193	-53		-53	140
9725055	WG - C8 - SM #McCloudWind	-336	336		336	
9725056	WG - C8 - SM -MoonPrism_2	-86	336		336	250
9725057	WG - C8 - SM #OaklandES	-336	336		336	
9725058	WG - C8 - SM #PittsburgEnergyStorage	-336	336		336	
9725059	WG - C8 - SM #Ripon	-336	336		336	
9725060	WG - C8 - SM - Sand Hill 2	-336	336		336	
9725061	WG - C8 - SM #Scarlett	362	336		336	698
9725063	WG - C8 - SM #Slate	-267	336		336	68
9725064	WG - C8 - SM #UltrapowerChineseStation	-336	336		336	
9725120	WG - C8 - SM -ChestnutWestside	-309	336		336	27
9725121	WG - C8 - SM -CooleyLandingBESS	-332	336		336	3
9725122	WG - C8 # SM -LittleBear3	-336	336		336	
9725123	WG - C8 # SM -LittleBear4	-336	336		336	
9725124	WG # post-COD mp # Q378# LECEFE	26,949		-26,949	-26,949	
9725160	WG - C8 - SM - Geysers Unit 11 Reconnect	-336	336		336	
9725140	LID SIS Restudy	-10,808				-10,808
9725202	WG - MMA # Q612# ThreeRocks	3,981		-3,981	-3,981	
9725260	WG - C8 - SM Primrose Engy Storage Cntr	-528	336		336	-192
9725844	CDWR BDCP Phase 2 sudy	6,912	11,332	-17,541	-6,209	703
9725845	SVP PST Re-study	-20,000	12,625	7,375	20,000	
9725921	WG Fast Track - Campbell Solar 1	1,210	-1,210		-1,210	
9725902	WG - MMA - Q272 - American Kings Solar	2,802		-2,802	-2,802	
9725922	WG-MMA-Q709-Golden Hills 2,GR Repower	6,069		-6,069	-6,069	
9725962	WG - MMA - Q644 - Chowchilla Solar	2,955		-2,955	-2,955	
9726062	Q900 Rio Bravo Solar 1 COD/Inverter Cha	2,967	855	-3,822	-2,967	
9726063	Q901 Wildwood Solar II COD/Inverter Cha	2,503	855	-3,358	-2,503	
9726064	Q972 Rio Bravo Solar 2 COD/Inverter Ch	2,967	855	-3,822	-2,967	
9726123	WG ISP q1092 Wellhead Gates Fac Stdy	5,052		-5,052	-5,052	
9726101	WG MMA Q720 and Q1002 Lassen Lodge CODCH	1,063				1,063
9726102	Travis AFB Feasibility Study	-11,370	6,547	4,823	11,370	
9726131	WG - MMA # Q529-Freshwater	4,547	230	-4,777	-4,547	
9726342	WG - MMA # Q526-Westside	768	2,774	-3,542	-768	
9726343	WG - MMA # Q532- WhitneyPoint	768	2,774	-3,542	-768	
9726381	WG - MMA # Q678- Burford	134	4,773	-4,907	-134	
9726382	WG - MMA # Q539- FrontierSolar	134	4,532	-4,667	-134	
9726383	WG - MMA # Q877- CaliforniaFlats	672	3,284	-3,956	-672	
9726640	WG - MMA - Q885- SKIC Solar		3,588	-3,588		
9726681	WG - Post-COD mp - Q687 - Columbia Solar		21,973	-21,973		
9726740	WG - 2016 Reassessment Gen Interconn		232,383	-232,383	-0	-0
9726860	WG MMA Q643W - Mustang		4,128	-4,128		
9726880	WG-MMA-Q643X-RETranquillity		5,095	-5,095		
9726940	WAPA - Cottonwood Olinda line work		36,025		36,025	36,025
9726960	WG - MMA - Q356 - Cuyama Solar		1,690	-1,690		
9727061	WG - C8P2 - Cluster 8 Phase 2		808,618		808,618	808,618
9727141	WG-MMA-Q723-LotusSolarFarm		1,016	-1,016		
9727142	WG-MMA-Q1032- RETranquillity8		5,354	-5,354		
9727162	WG - MMA - Q901- Wildwood II		2,100	-2,100		
9727240	WG - ISP - HORUS San Luis North & South		19,899	-19,899		
9727280	CDWR Waterfix - Facility Study		675	-675		
9727340	WG - C9 - SM - Trafalgar 2		5,189	-5,189		
9727341	WG - C9P1 - Cluster 9 Phase 1		745,706		745,706	745,706
9727320	WG - C9 - SM - Yuba Solar 1		5,833	-5,833		
9727301	WG - MMA - Q645A- SiriusSolar		2,438	-2,438		
9727342	WG - C9 - SM - Cantua Kamm Solar		6,467	-6,467		
9727343	WG - C9 - SM - Fairfax Solar 1		5,404	-5,404		
9727344	WG - C9 - SM - Niles Solar 1		4,756	-4,756		
9727360	WG - C9 - SM - Excelsior Solar 1		7,206	-7,206		
9727380	WG - MMA - Q779- WrightSolar		679	-679		

9727381	WG - C9 - SM - Rancho Fresno Storage Far		6,767	-6,767		
9727361	WG - C9 - SM - Alamo Springs Solar 3		6,686	-6,686		
9727402	WG - C9 - SM - Coyote Creek		6,022	-6,022		
9727403	WG - C9 - SM - Nikko		4,339	-4,339		
9727404	WG - C9 - SM - Kola		5,271	-5,271		
9727405	WG - C9 - SM - Pentland Solar 1		5,202	-5,202		
9727406	WG - C9 - SM - Rolling Hills Solar		6,952	-6,952		
9727407	WG - C9 - SM - Heartland Solar		6,223	-6,223		
9727408	WG - C9 - SM - LeGrand Solar		5,309	-5,309		
9727409	WG - C9 - SM - Crows Landing		5,669	-5,669		
9727410	WG - C9 - SM - American Kings 9		4,986	-4,986		
9727411	WG - C9 - SM - Huron Solar 1		4,376	-4,376		
9727412	WG - C9 - SM - Heartland Solar 2		6,994	-6,994		
9727413	WG - C9 - SM - Pentland Solar 2		4,879	-4,879		
9727414	WG - C9 - SM - Cantua Creek Solar		4,522	-4,522		
9727415	WG - C9 - SM - Tornado Solar		5,895	-5,895		
9727416	WG - C9 - SM - Jacalitos Solar		4,733	-4,733		
9727417	WG - C9 - SM - Paradise Solar 1		4,048	-4,048		
9727418	WG - C9 - SM - BGarcia Solar		7,236	-7,236		
9727419	WG - C9 - SM - Cantua Orchards Solar		5,377	-5,377		
9727420	WG - C9 - SM - Temblor View Solar		6,271	-6,271		
9727421	WG - C9 - SM - Knights Landing		5,759	-5,759		
9727422	WG - C9 - SM - Corning Solar 1		5,651	-5,651		
9727423	WG - C9 - SM - SEMI TROPIC		5,405	-5,405		
9727440	WG - C9 - SM - Golden Rectangle		4,197	-4,197		
9727441	WG - C9 - SM - Cinco		4,748	-4,748		
9727442	WG - C9 - SM - Los Arcos Solar		1,970	-1,012	958	958
9727443	WG - C9 - SM - Pelican Island		5,762	-5,762		
9727444	WG - C9 - SM - Humboldt Hybrid		8,330	-8,330		
9727445	WG - C9 - SM - Los Banos Hybrid		6,602	-6,602		
9727446	WG - C9 - SM - Napa Lake Wind Farm		6,277	-6,277		
9727447	WG - C9 - SM - SPI Quincy		4,495	-4,495		
9727448	WG - C9 - SM - SPI Sonora		5,947	-5,947		
9727449	WG - C9 - SM - SF Crown		5,323	-5,323		
9727450	WG - C9 - SM - Six Points Solar		5,867	-5,867		
9727461	WG - C9 - SM - Northern Orchard 2 Solar		5,601	-5,601		
9727462	WG - C9 - SM - Northern Orchard 3 Solar		6,222	-6,222		
9727463	WG - C9 - SM - Borden Energy Storage		3,964	-3,964		
9727464	WG - C9 - SM - Weber Energy Storage		4,820	-4,820		
9727465	WG - C9 - SM - Apple Hill Energy Storage		3,889	-3,889		
9727466	WG - C9 - SM - South Kern Front CHP		2,097		2,097	2,097
9727467	WG - C9 - SM - Mulqueeney Ranch Wind		4,880	-4,880		
9727468	WG - C9 - SM - Smyrna Solar		6,139	-6,139		
9727469	WG - C9 - SM - Westlands Solar Two		4,071	-4,071		
9727470	WG - C9 - SM - Las Hermanas BESS		10,410	-10,410		
9727471	WG - C9 - SM - SF West Kamm		6,716	-6,716		
9727472	WG - C9 - SM - Westlands Grape		3,694	-3,694		
9727473	WG - C9 - SM - Westlands Cherry		3,721	-3,450	271	271
9727474	WG - C9 - SM - San Joaquin East		5,507	-5,507		
9727475	WG - C9 - SM - Westwood Energy Center		5,779	-5,779		
9727476	WG - C9 - SM - SF Cantua		5,950	-5,950		
9727477	WG - C9 - SM - Walker Ridge		6,360	-6,360		
9727478	WG - C9 - SM - Proxima Solar		8,491	-8,491		
9727456	WG - C9 - SM - Byron Highway Solar		4,684	-4,684		
9727479	WG - C9 - SM - Almond Grove Solar Projec		3,968	-3,968		
9727500	WG - MMA - Q1029- LittleBearSolar2		498	-498		
9727485	WG - C9 - SM - Malaga Storage Project		5,089	-5,089		
9727486	WG - C9 - SM - Martin Storage Project		2,762	-2,762		
9727480	WG - MMA - Q1028 LittleBearSolar		1,004	-1,004		
9727540	WG - MMA - Q1032- Tranquility8-newMMA		1,141	-1,141		
9727700	WG - MMA -Q705- BlackwellFrt		2,589		2,589	2,589
9727760	WG - Repowering Study - SPI-Sonora		12,468		12,468	12,468
9727720	SFPUC - Potrero Interconnection		58,457	-86,707	-28,250	-28,250
9727723	WG - MMA - Q965- SPWRJava		2,747		2,747	2,747
9727724	WG - MMA - Q648- OroLomaIV		1,330	-1,330		
9727881	WG - Repowering Study - SPI-Quincy		6,857		6,857	6,857
9727900	WG - MMA - Q1036- Mustang2		3,527	-3,527		
9727980	LBNL Capacity Increase		8,974	-7,100	1,874	1,874
9728180	2016 Merced ID Load Interconnection Syst		52,277	-45,000	7,277	7,277
9728201	WG - MMA - Q709 - GoldenHills - 2016 MMA		3,588		3,588	3,588

9728260	WG - MMA - Q829- PanocheSolar		1,726	-1,726		
9728340	SVP Breaker Replacement		7,669	-20,000	-12,331	-12,331
9728360	Travis AFB Facility Study		7,741	-75,000	-67,259	-67,259
9728480	WG # MMA # Q705- Frontier-2016COD		463		463	463
9728526	Port of Stockton Load Increase		6,157	-30,000	-23,843	-23,843
9728582	WG # MMA # Q720&Q1002		929		929	929
9728645	WG # MMA # Q720&Q1002		468	-468	-0	-0
9728900	WG - MMA - Q272-2016COD		1,116		1,116	1,116
9728960	WG - MMA - Q679-Dec2016		795		795	795
9729004	WG # MMA # Q744-2016COD		636		636	636
9729040	2016 Merced ID Load Interconnection Faci		2,546		2,546	2,546
9707780	CP-Martin 115/60 kV Upgrade Project	486	3,608		3,608	4,094
9713955	WL - Tesla Tracy 230kV Line 1 Reloc-FAS			13,216	13,216	13,216
9715022	WL - WAPA Red Bluff PP-IFAS	-15,789		15,789	15,789	
9715140	WG - Rough & Ready Solar - SIS	-15,519				-15,519
9717186	WL - SVP Phase-Shifting Trans Study	43,721		-87,442	-87,442	-43,721
9720462	Lathrop Irrigation District Load Study			10,808	10,808	10,808
9722206	Trans Bay Cable Quick Start Study	-26,767	23,116		23,116	-3,651
9717187	WL - CA HiSpeed Train Interconnect Study	556,476	2,006,137	-2,433,020	-426,883	129,593
9714755	WL - KMPUD-IFAS	63,553				63,553
	Transmission Total	**1,868,704**	**5,188,727**	**-5,204,059**	**-15,332**	**1,853,373**

Schedule Page: 231 Line No.: 23 Column: a

Order	Order Description	BALANCE 12/31/2015	COSTS INCURRED PERIOD ENDED 12/31/2016	REIMBURSEMENTS RECEIVED PERIOD ENDED 12/31/2016	NET ACTIVITY PERIOD ENDED 12/31/2016	BALANCE 12/31/2016
9720265	WDT-ZWEDC Phase 1, CL6 Deliv Assess	35,657		-35,657	-35,657	
9720266	WDT-OakLeafSolar-Reedly,CL6 Deliv Assess	35,657		-35,657	-35,657	
9720269	WDT - Oak Leaf Solar X, CL6 Deliv Assess	35,657		-35,657	-35,657	
9720980	R21-Transmission DTT Study - E&J Galllo			20,000	20,000	20,000
9722340	R21 - 2076 Mass - Detailed Study	6,116	140	-6,256	-6,116	
9723321	WDT Freethy Industrial Park Facility Sty	-2,793		2,793	2,793	
9723328	WDT-Maricopa East Solar PV 2-Ind Study	-31,687		31,687	31,687	
9723423	WDT - Bakersfield 1- System Impact Study	-51,001		51,001	51,001	
9723520	WDT - 54.78 Buchanan - Fast Track Study	1,342		-1,342	-1,342	
9723521	WDT - 56.2677 Larkin - Fast Track Study	1,612	847	-2,459	-1,612	
9723527	WDT - 5.915 Pierce - Fast Track Study	1,851	463	-2,314	-1,851	
9723531	WDT - 11.2500 Van Ness - Fast Track Stdy	1,608	420	-2,029	-1,608	
9723534	WDT - 18.3210 Gough - Fast Track Study	55		-55	-55	
9723535	WDT - 21.3715 California Fast Track Stdy	87		-87	-87	
9723536	WDT - 22.1500_1514 Geneva Fast Track Sty	1,515	547	-2,061	-1,515	
9723537	WDT - 23.500-506 Bartlett Fast Track Sty	1,515	547	-2,061	-1,515	
9723538	WDT - 24.1547 Clay- Fast Track Study	1,240	504	-1,744	-1,240	
9723539	WDT - 26.1440 Sutter - Fast Track Study	1,721	463	-2,183	-1,721	
9723540	WDT Natoma Storage System Impact Study	857		-857	-857	
9723541	WDT El Dorado Storage System Impact Stdy	325		-325	-325	
9723542	WDT Golden Hill Storage System Impct Sty	-1,495		1,495	1,495	
9723567	WDT - 33.520 Buchanan - Fast Track Study	1,558	378	-1,936	-1,558	
9723560	WDT - 57.1870 Pacific - Fast Track Study	1,323		-1,323	-1,323	
9723563	WDT - 1.400 Duboce - Fast Track Sty	1,667	420	-2,087	-1,667	
9723565	WDT - 25.2238 Hyde - Fast Track Sty	597		-597	-597	
9723568	WDT 34.1855 10th Ave - Fast Track Study	441		-441	-441	
9723570	WDT- 37.1355 Lombard - Fast Track Study	668	294	-962	-668	
9723662	WDT- Sirius 10 - Fast Track Study	-372	372		372	
9723900	WDT - Lakeview Dairy Biogas Indep. Study	-2,241	750	1,491	2,241	
9723901	WDT - West-Star Dairy Biogas Indep Study	-942	834	108	942	
9724181	R21 2076 Maas - Facilities Study	-15,000		15,000	15,000	
9724160	R21 City of San Jose WPCP - Detailed Sty	230				230
9724282	1078-WD - CLK 240 - Supplemental Review	-215		215	215	
9724320	R21 Genentech Inc. Non Exp Detailed Sty	-41,118	3,176	37,942	41,118	
9724361	R21 NEMMT - City of Bakersfield Restudy	-1,005		1,005	1,005	
9724403	WDT-50001 SCWA North&South Ponds Fst Trk	-31,526				-31,526
9724405	WDT-50004 SCWA R5 Pond Fast Track Study	817		-817	-817	
9724421	WDT - Chevron 8.5 Independent Study	-45,290		45,290	45,290	
9724441	WDT - Dres Quarry 2.1 - Supplemental Rev	-836		836	836	
9724442	WDT - Shingle Springs - Fast Track Study	676		-676	-676	
9724500	WDT Sonoma Valley PV 100kW - Fast Track	1,313		-1,313	-1,313	
9724540	McFarland Solar 0157WD System Impact Sty	-2,305	841	1,464	2,305	
9724541	Chevron 2MW 1122-WD Supplemental Review	7,136		-7,136	-7,136	
9724580	WDT - Morgan Hill BESS - Fast Track Sty	571		-571	-571	

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) 03/31/2017	2016/Q4

FOOTNOTE DATA

9724660	WDT New Slab Creek Powerhouse Fast Track	4,354		-4,354	-4,354	
9724661	WDT - Peacock Phase II Fast Track Study	774		-774	-774	
9724662	WDT Sirius Solar Phase II Fast Track Sty	937		-937	-937	
9724683	TO-Green Ridge Repowering Facilities Sty	7,405				7,405
9724742	WDT- Porter B Energy Storage - Indep Sty	-7,311	15,046	-10,000	5,046	-2,265
9724743	WDT- Madera 1 - Fast Track Study	304		-304	-304	
9724700	WDT-Burdell Solar Energy Fast Track Sty	4,630		-4,630	-4,630	
9724704	WDT- CE&S Dairy Biogas - Independent Sty	-5,246	1,539		1,539	-3,706
9724740	50002 SCWA Ponds 1 & 2 1149-WD Supp Rev	195				195
9724741	50004 SCWA R5 Pond 1150-WD Supp Rev	-177		177	177	
9724703	WDT - Templeton B Energy Storage- ISP	-6,140	210		210	-5,929
9724780	WDT - Porter Solar - Independent Study	-6,638				-6,638
9724900	WDT - Buck Institute Cluster Study	-45,845	1,303	44,542	45,845	
9724901	WDT - Peacock Phase II - Independent Sty	-2,400		2,400	2,400	
9724926	R21 Scheid Vineyards Corp Detailed Study	464		-464	-464	
9724927	R21 Wal-Mart Stores Inc. Detailed Study	0	-0		-0	
9724920	WDT Bakersfield Industrial 1(A) Fast Trk	6,910		-6,910	-6,910	
9724922	WDT - Manteca Land 1 Fast Track Study	745		-745	-745	
9724931	WDT Delano Land 1 - Fast Track Study	8,589				8,589
9724932	WDT Kern County Industrial 1 - Indep Sty	27,390				27,390
9725015	WDT Madera 1 - Supplemental Review	173	-173		-173	
9725080	0963-WD Binford Rd Storage Facility Sty	-12,801		12,801	12,801	
9725082	1208-WD Bakersfield Indus 1 (B) Supp Rev	1,649				1,649
9725065	WDT - Porter B Energy Storage Deliv Sty	-1,054	-8,642	10,000	1,358	304
9725066	WDT - Porter Solar Devlierability Study	-5,054		5,054	5,054	
9725069	WDT - Templeton B Energy Storage Del Sty	3,627	395	-4,022	-3,627	
9725070	WDT - New Slab Creek Powerhouse Del Sty	8,247				8,247
9725180	WDT-Black Diamond Energy Storage-FastTrk	2,196		-2,196	-2,196	
9725220	EID Powerhouse Post-COD Telecom Study	-6,408	6,095		6,095	-312
9725240	WDT - Delano Land Project - Supp Review	249		-249	-249	
9725281	Estrella Substation - Facilities Study		43,422	-50,000	-6,578	-6,578
9725300	ConEdison Solar Post-COD Telecom Study	15,483	46,763		46,763	62,246
9725340	WDT-Sirius Solar Phase II 740kw Fast Trk	318		-318	-318	
9725380	1221-WD Burdell Solar Energy - Supp Rev	3,230				3,230
9725760	WDT-Apex Energy-Madera 1-1.5MW-FastTrk	1,187		-1,187	-1,187	
9725802	WDT-Apex Energy-Madera 1-1.0MW-FastTrk	441		-441	-441	
9725820	1207-WD Bakersfield Indus 1 (A) SIS	-3,638	5,693		5,693	2,054
9725841	WDT- Orange Cove 2 - Fast Track	6,547				6,547
9725842	R21 Apple Enos 147238 - Detailed Study	-7,497	362	7,134	7,497	
9725843	R21 Apple Enos 147273 - Detailed Study	-7,330	198	7,133	7,330	
9725880	1227WD Black Diamond Energy Stor Sup Rev	-275	330		330	54
9725900	8.4 MW Frick Wind Repower Facilities Sty	3,687	1,007	-4,697	-3,690	-3
9725901	2.99 MW Dyer Wind Repower Facilities Sty	651	-700	-651	-1,351	-700
9725963	WDT New Slab Creek Pwrhse Facilities Sty	-8,485	1,664		1,664	-6,821
9725960	WDT El Dorado Storage - Facilities Study	-12,871		12,871	12,871	
9726012	WDT - Peacock Phase II - Facility Study	-13,759				-13,759
9726013	WDT - 50003 SCWA R4 Fast Track Study	6,880				6,880
9726041	WDT - Sirius Solar Phase 2 Suppl. Review	438		-438	-438	
9726044	1223-RD Indian Valley Hydro - Det. Study	-7,298	3,166		3,166	-4,133
9726040	R21 Genentech - Facilities Study	-11,520	-1,980		-1,980	-13,500
9726081	WDT Collins Small Bioenergy Indep Study	-8,578	12,877		12,877	4,299
9726124	WDT - Madera 1 - 1.0 Supplemental Review	-1,020		1,020	1,020	
9726126	WDT - DRES Quarry 2 (09_2015) Fast Track	2,199				2,199
9726127	WDT - Camden 1 FIT 1 PV - Fast Track	912		-912	-912	
9726125	GJ TeVelde Ranch Pacific Rim Detail. Sty	-9,501	4,659		4,659	-4,842
9726129	R21 193203 Sierra Nevada Brewing Det Sty	-1,834	440		440	-1,394
9726128	R21 Hanford Renewable Energy Detail Sty	-7,566	4,090		4,090	-3,475
9726130	WDT - McFarland Solar - Facilities Study	-15,000	2,032	12,968	15,000	
9726132	WDT - Castroville Energy Storage - ISP	-8,248	14,169		14,169	5,920
9726180	R21-US Air Force Civil Engrs-Det Study	-69,301	12,199		12,199	-57,102
9726241	WDT - Camden 1 FIT 1, PV - Supp. Review	-923		923	923	
9726300	WDT Black Diamond Energy 11_2015 F Trk	930	2,422		2,422	3,352
9726360	WDT - Bellanave Dairy Biogas - Indep Sty	-9,187	12,058		12,058	2,871
9726361	1252-WD 50003 SCWA R4 Pond Supp Review	-1,950	6,312		6,312	4,362
9726400	0026-WD G2 Energy Ostrom Rd Replace Gen	-757	1,779	-1,022	757	
9726421	1274-WD Black Diamond Energy - Suppl Rev	-2,500				-2,500
9726443	R21 Burney-Hat Creek Bio 12_15 Det. Stdy	-9,667	19,685	-10,018	9,667	
9726540	WDT - HZI Waste Connect Fac SLO Fast Trk		1,034	-1,034		
9726522	WDT - EEPV1 Fast Track Study		2,160	-2,160		
9726560	WDT - Eagle Dec_2015 Fast Track Study		1,755	-1,755		

FOOTNOTE DATA

9726605	WDT - Oakland ES - System Impact Study		4,143	-4,143		
9726601	Scheid Vineyards 1258-RD Detailed Study		6,569	-10,000	-3,431	-3,431
9726680	Corcoran Irrig Dist (1269-RD) Det Study		9,242	-10,000	-758	-758
9726700	R21 S Joaquin Cnty (257384) Detailed Sty		7,917	-10,000	-2,083	-2,083
9726761	WDT- Henrietta D Energy Storage LLC ISP		11,908	-60,800	-48,892	-48,892
9726800	Codding Ent Ltd Ptnshp East Detailed Sty		2,426	-10,000	-7,574	-7,574
9726801	Codding Ent Ltd Ptnshp West Detailed Sty		3,161	-10,000	-6,839	-6,839
9727000	WDT- Bar20 Dairy Biogas ISP		9,041	-10,800	-1,759	-1,759
9726882	1289-WD - Eagle - Supp Review		3,560	-3,560		
9727040	1311-WD Paso Robles Solar 1 Indep Study		11,588	-60,800	-49,212	-49,212
9727041	WDT Paso Robles Solar 1 FCDS Full Capac		624	-10,000	-9,376	-9,376
9727080	WDT - EEPV1 Supplemental Review		1,686	-2,500	-814	-814
9727121	WDT Ripon Independent Study Process		2,301	-5,000	-2,699	-2,699
9727122	WDT Ripon FCDS Full Capac Deliver Status		37,640	-10,000	27,640	27,640
9727160	WDT - G2 Energy Ostrom Road Indep Study		6,682	-10,800	-4,118	-4,118
9727161	WDT Buck Institute Full Capacity Del Sty			-10,800	-10,800	-10,800
9727182	R21 Verwey-Madera Dairy Digester Det Sty		14,511	-10,000	4,511	4,511
9727183	R21 Verwey-Hanford Dairy Digestr Det Sty		7,496	-10,000	-2,504	-2,504
9727180	WDT Cabrillo Wind Energy Full Capacity		379		379	379
9727181	WDT Cabrillo Wind Energy Indep Study		36,513	-5,000	31,513	31,513
9727163	WDT Stockton RV/Boat Stg - Fast Track		4,381	-800	3,581	3,581
9727164	WDT Oakley Boat RV Stg Phase II Fast Trk		3,899	-800	3,099	3,099
9727220	1289-WD Eagle - Independent Study		11,221	-10,000	1,221	1,221
9727260	R21 Van Der Kooi Dairy Digstr Detail Sty		3,062	-10,000	-6,938	-6,938
9727300	WDT-HZI-Waste Conn Fac SLO 4-16 Indep Sy		9,434	-10,800	-1,366	-1,366
9727460	WDT-Kern County Industrial 1 Indep Study		9,571	-10,800	-1,229	-1,229
9727482	R21-Lone Oak Dairy Digester-Det Study		5,732	-10,800	-5,068	-5,068
9727483	WDT-Coalinga Energy Storage-Indep Study		1,714	-65,800	-64,086	-64,086
9727484	WDT-Coalinga Energy Storage-FullCapacity		7,011	-10,000	-2,989	-2,989
9727520	Columbia Solar Fiber Upgrade Telecom Sty		9,427		9,427	9,427
9727580	R21 OpenSky Dairy Dgstr Genset 2 Det Sty		3,813	-10,000	-6,187	-6,187
9727620	R21Taylor Farms Enos 205445 Detailed Sty		11,366	-10,800	566	566
9727640	WDT Oakley Boat RV Stg Phase II Supp Rev		23,587	-2,500	21,087	21,087
9727641	WDT EtaGen Demo Proj - Fast Track Study		1,336	-800	536	536
9727660	WDT- Yuba Solar Millenium Fund Fast Trk		1,035	-800	235	235
9727663	R21 Cal Poly SLO 291865 Detailed Study		3,419	-10,800	-7,381	-7,381
9727740	1250-WD Collins Small Bioenergy Fac Sty		1,717	-15,000	-13,283	-13,283
9727780	R21 - Indian Valley Power Detailed Study		3,874	-10,800	-6,926	-6,926
9727820	WDT- Helium - Fast Track Study		1,362	-800	562	562
9727821	WDT- Neon - Fast Track Study		75	-800	-725	-725
9727822	WDT- Argon - Fast Track Study		1,163	-800	363	363
9727823	WDT- Xenon - Fast Track Study		2,613	-800	1,813	1,813
9727824	WDT- Krypton - Fast Track Study		1,478	-800	678	678
9727921	R21 - Celestial Valley Elec Detailed Sty		947	-10,800	-9,853	-9,853
9727922	R21 - 2143 Dacy Detailed Study			-10,800	-10,800	-10,800
9728040	WDT - 1358-WD Krypton - Sup Rev		1,995	-2,500	-505	-505
9728041	WDT - 1356-WD Argon - Sup Rev		562	-2,500	-1,938	-1,938
9728042	WDT - 1354-WD Helium - Sup Rev		1,912	-2,500	-588	-588
9728043	WDT-1302-WD-Bar20 Dairy Biogas-Fac Stdy		3,658	-15,000	-11,342	-11,342
9728080	WDT- 1355-WD Neon Supplemental Review		1,047	-2,500	-1,453	-1,453
9728081	WDT- 1357-WD Xenon Supplemental Review		2,153	-2,500	-347	-347
9728100	Q557 White River 2 - Facility Study		11,294	-10,000	1,294	1,294
9728120	WDT - Radon - Fast Track Study		2,110	-800	1,310	1,310
9728140	R21 Chevron 309256 NEM 2.0 Detailed Sty		6,108	-75,800	-69,692	-69,692
9728200	WDT- Chlorine Fast Track Study		3,215	-800	2,415	2,415
9728243	WDT- Luma Hill SC1 Fast Track Study		928	-800	128	128
9728244	WDT- PH1 Sonoma Energy Fast Track Study		1,962	-800	1,162	1,162
9728402	WDT CMSA Renewable Energy Fast Track Sty		1,840	-800	1,040	1,040
9728420	R21 True Leaf Farms 317838 Detailed Sty		368	-10,800	-10,432	-10,432
9728500	WDT - Apple Hill ES 1 Independent Study		485	-60,800	-60,315	-60,315
9728501	WDT - Apple Hill ES 2 Independent Study		1,876	-60,800	-58,924	-58,924
9728502	WDT - Apple Hill ES 1 Deliverability Sty			-10,000	-10,000	-10,000
9728503	WDT - Apple Hill ES 2 Deliverability Sty			-10,000	-10,000	-10,000
9728520	WDT West Biofuels Power Fast Track Study		710	-800	-90	-90
9728521	WDT Paso Robles Solar 2 Independent Sty		77	-10,800	-10,723	-10,723
9728522	WDT Paso Robles Solar 2 Deliverab. Study			-10,000	-10,000	-10,000
9728527	WDT-Bodega Energy West-Fast Track Study		1,381	-800	581	581
9728528	WDT-Petaluma Solar West-Fast Track Study		1,381	-800	581	581
9728525	Friant Dam Hydro Generating Fac Post COD		13,795		13,795	13,795
9728580	R21 - Project Daisy Detailed Study		566	-10,800	-10,234	-10,234

9728583	WDT - 1372-WD Radon System Impact Study		184	-10,000	-9,816	-9,816
9728584	WDT - DRES Quarry 2.2 Fast Track Study		1,405	-800	605	605
9728529	R21 Pacific Ethanol NEM 2.0 Detailed Sty			-10,800	-10,800	-10,800
9728601	WDT 1384-WD CMSA Renewable Supp Review			-2,500	-2,500	-2,500
9728602	WDT 1122-WD Chevron 2MWI Supp Review		1,289		1,289	1,289
9728640	WDT - 7.1660 Bay - Fast Track Study		79	-800	-721	-721
9728641	WDT - 51.3820 Scott - Fast Track Study		456	-800	-344	-344
9728642	WDT - 50.2898 Jackson - Fast Track Study		456	-800	-344	-344
9728643	WDT - 18.3210 Gough - Fast Track Study		456	-800	-344	-344
9728644	WDT - 10.1690 North Point Fast Track Sty		456	-800	-344	-344
9728663	WDT - Poco Power - Fast Track Study		1,109	-800	309	309
9728700	WDT - 50004 SCWA R5_Nov16 Fast Track Sty		755	-800	-45	-45
9728701	WDT - 50001 SCWA North/South Ponds Indep		378	-57,800	-57,422	-57,422
9728761	R21 Dalena Farms 331031 NEMA 2.0 Det Sty		189	-10,800	-10,611	-10,611
9728762	R21 Sun World - Harris - Detailed Study			-10,800	-10,800	-10,800
9728800	R21 David Tevelde Dairy Digester Det Sty			-10,800	-10,800	-10,800
9728840	WDT-Rnd Valley Ind Tribes Biom Indep Sty		229	-10,800	-10,571	-10,571
9728862	Q653EA SKIC 20 Telecom Modification		2,378		2,378	2,378
9728863	Q885 SKIC 10 Telecom Modification		2,832		2,832	2,832
9728922	1357-WD Xenon Independent Study			-10,000	-10,000	-10,000
9728923	WDT- Semperviren 1 Fast Track Study		239	-800	-561	-561
9728961	1398-WD Bodega Energy West Suppl Review			-2,500	-2,500	-2,500
9728962	1399-WD Petaluma Solar East Suppl Review			-2,500	-2,500	-2,500
9728963	R21 Target Corp Shafter Detailed Study			-10,000	-10,000	-10,000
9729000	1413WD 50004 SCWA R5 Supplemental Review			-2,500	-2,500	-2,500
9726820	R21-Livermore Community Solar Frm-Det St		21,107	-10,000	11,107	11,107
9727880	1313-RD City of Soledad REMAT Detail Sty		5,593	-10,000	-4,407	-4,407
9728020	R21-Mad River Energy Co-Detailed Study		7,561	-10,800	-3,239	-3,239
9728141	R21 Napa Recycling Biomass Detailed Sty		2,248	-10,800	-8,552	-8,552
9728661	R21Sonoma Cty Water 1349-RD Detailed Sty		1,173	-10,000	-8,827	-8,827
	Distribution Total	**-280,047**	**634,983**	**-926,882**	**-291,899**	**-571,946**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	AB802 Memo Account - Electric		236,044	400		236,044
2	(amortization: < 12 months)					
3	AB802 Memo Account - Gas		193,127	400		193,127
4	(amortization: < 12 months)					
5	Acc Amt - Plant RA Tax	(154,846,337)		405	3,520,572	-158,366,909
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	(560,911,723)		405	43,335,000	-604,246,723
10	(amortization: 12 years)					
11	Balancing Account - Utility Generation	122,195,317	2,375,260,844	400	2,449,649,885	47,806,276
12	(amortization: < 12 months)					
13	BCA Charge Account	2,398,006	4,550,925	400	3,225,104	3,723,827
14	(amortization: <12 months)					
15	CA Alternate Rates for Energy Program-Electric	36,296,278	526,861,202	400	545,402,795	17,754,685
16	(amortization: < 12 months)					
17	CA Alternate Rates for Energy Program-Gas	(25,593,830)	114,475,955	400	103,150,102	-14,267,977
18	(amortization: < 12 months)					
19	CA Solar Initiative Thermal Program Memo Account	6,815,357	8,752,448	400	6,217,901	9,349,904
20	(amortization: < 12 months)					
21	Catastrophic Event Memorandum Account	26,258,000	125,787,680	182.3	26,258,000	125,787,680
22	(amortization: <12 months)					
23	CEE Incentive Electric Balancing Account	24,455,107	13,387,013	400	20,478,475	17,363,645
24	(amortization: < 12 months)					
25	CEE Incentive Gas Balancing Account	1,436,366	2,938,613	400	2,061,186	2,313,793
26	(amortization: < 12 months)					
27	Community Choice Aggr. Implem. Costs Balan. Acct.	4,024,474	19,865	182.3		4,044,339
28	(amortization: < 12 months)					
29	CORE BROKERAGE FEE	1,552,880	6,474,064	400	6,562,540	1,464,404
30	Amortization : < 12 MONTHS					
31	Core Fixed Cost Gas Balancing Account	492,806,996	2,287,629,151	400	2,418,025,121	362,411,026
32	(amortization: < 12 months)					
33	Core Pipeline Demand Charge Account	11,020,059	511,081,145	400	509,664,814	12,436,390
34	(amortization: < 12 months)					
35	Customer Data Access B/A-Elec Rev	(3,572,187)	10,503,175	400	350,988	6,580,000
36	(amortization: 3 years)					
37	Deferred Debit - Gas Reserves (Contra Balancing Ac	(24,117,657)	1,124,643,059	400	1,445,895,183	-345,369,781
38	(amortization: < 12 months)					
39	Demand Response Expenditures B/A (DREBA)	611,671	1,287,485	400	2,768,416	-869,260
40	amortization: < 12 months					
41	Department of Energy Litigation Balancing Account	(114,091,942)	114,119,624	182.3	28,208,549	-28,180,867
42	(amortization: > 12 months)					
43	Diablo Canyon Seismic Studies Balancing Acct	47,965,189	5,649,600	182.3	34,180,593	19,434,196
44	TOTAL	8,666,911,679	25,045,124,039		24,405,351,301	9,306,684,417

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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	Distribution Revenue Adjustment Mechanism	380,346,823	4,674,839,879	400	4,923,289,366	131,897,336
3	(amortization: < 12 months)					
4	DWR Power Charge Collection Balancing Account	(7,837,185)	44,958,526	400	40,470,866	-3,349,525
5	(amortization: < 12 months)					
6	Dynamic Pricing Memorandum Account	507,688	4,180,850	182.3	4,178,344	510,194
7	(amortization: < 12 months)					
8	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
9	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
10	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
11	Electric Balancing Account Reserve Account	(46,841,308)	133,272,350	182.3	324,357,815	-237,926,773
12	(amortization: < 12 months)					
13	Electric Hazardous Substance Balancing Account	21,112,230	41,464,527	182.3	42,377,704	20,199,053
14	(amortization: < 12 months)					
15	Electric Price Risk Management - Current	96,144,282	252,008,600	555	311,092,548	37,060,334
16	Electric Price Risk Management - NonCurrent	138,081,121	426,511,748	555	472,338,008	92,254,861
17	Electric Program Investment Charge	3,488,110	86,165,170	400	86,150,399	3,502,881
18	(amortization: < 12 months)					
19	End-Use Customer Refund Adjustment	342,303	89,653,533	400	91,325,503	-1,329,667
20	(amortization: < 12 months)					
21	Energy Data Ctr Memo Acct - Electric	267,057	121,945	182.3		389,002
22	(amortization: > 12 Months)					
23	Energy Data Ctr Memo Acct - Gas	218,501	99,714	182.3		318,215
24	(amortization: > 12 Months)					
25	Energy Recovery Bonds Balancing Account	(21,715,898)	23,211,485	400	2,002,702	-507,115
26	(amortization: < 12 months)					
27	Energy Resource Recovery Account	128,314,620	4,330,867,829	400	4,362,428,890	96,753,559
28	(amortization: < 12 months)					
29	Environmental Compliance	144,465,194	39,294,838	182.3	35,942,860	147,817,172
30	(amortization: 32 years)					
31	Environmental Compliance Non-HSM	63,395,762	1,147,286	228.4	30,736,387	33,806,661
32	(amortization: 32 years)					
33	Family Electric Rate Assistance Balancing Acct	3,621,240	5,565,049	400	3,621,311	5,564,978
34	(amortization: < 12 months)					
35	FASB 109 Regulatory Asset	3,592,739,981	1,017,511,255	282	213,024,051	4,397,227,185
36	(amortization: 1-45 years)					
37	FASB 109 Regulatory Asset Amortzation	(538,567,000)				-538,567,000
38	(amortization: 1-45 years)					
39	FIN 47 - Regulatory Asset	16,982,021	692,860	101		17,674,881
40	Financing Costs - Current	2,067,701		428	442,477	1,625,224
41	(amortization: < 12 months)					
42	Financing Costs Regulatory Asset	20,039,965	442,477	428	2,048,035	18,434,407
43	(amortization: 20 years)					
44	TOTAL	8,666,911,679	25,045,124,039		24,405,351,301	9,306,684,417

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	03/31/2017	End of 2016/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	Fire Hazard Prevention Memo Acct	509,214	158,418	182.3	6,522	661,110
2	(amortization: < 12 Months)					
3	Gas Core Firm Storage Account	707,814	63,201,066	400	60,956,287	2,952,593
4	(amortization: < 12 months)					
5	Gas Hazardous Substance Balancing Account	49,804,849	97,292,689	182.3	100,271,735	46,825,803
6	(amortization: < 12 months)					
7	Gas Hazardous Substance Regulatory Asset	337,085,451	91,687,956	182.3	83,866,673	344,906,734
8	(amortization: 32 years)					
9	Gas Leak Survey and Repair Balancing Account	(3,633,440)	119,220,799	182.3	133,301,975	-17,714,616
10	Amortization : <12 MONTHS					
11	Gas Non-Hazardous Substance Regulatory Asset	136,003,670	4,606,500	228.4	8,931,490	131,678,680
12	(amortization: 32 years)					
13	Gas Pipeline Expense and Capital Balancing Account	6,112,589	2,420,818	400	6,113,559	2,419,848
14	(amortization: <12 months)					
15	Gas Price Risk Management - Current	1,847,856	9,331,168	807	9,839,163	1,339,861
16	GPBA-Greenhouse Gas Compliance Subaccount	36,276,900	93,955,739	400	40,549,249	89,683,390
17	(amortization: < 12 months)					
18	Gas Public Purpose Program Surcharge Memo Acct	42,680,942	268,547,299	186	264,059,972	47,168,269
19	(amortization: < 12 months)					
20	Gas Transmission and Storage Memo Account	(35,966,355)	824,099,280	400	332,330,759	455,802,166
21	(amortization: < 12 months)					
22	Gas Transmission and Storage Revenue Sharing Mech.	1,290,550	65,516,532	400	112,744,773	-45,937,691
23	(amortization: < 12 months)					
24	GPBA - GHG Operational Cost Subaccount		22,904,048	400	8,724,683	14,179,365
25	(amortization: < 12 months)					
26	GREEN TARIFF SHARED RENEWABLES MEMORANDUM	2,246,168	2,172,352	400	234,119	4,184,401
27	(amortization: < 12 months)					
28	Greenhouse Gas Expense Memo Account - E	(3,926,166)	1,021,780	400	16,966	-2,921,352
29	Greenhouse Gas Expense Memo Account - G	56,731	284,288	400	55,094	285,925
30	(amortization: < 12 months)					
31	Hydro Licensing Balancing Account	(27,067,549)	410,356	182.3	20,929,998	-47,587,191
32	(amortization: > 12 months)					
33	Land Conserv. Plan Env. Remediation Memo Acct.	2,106,043	3,286,707	182.3	2,106,043	3,286,707
34	(amortization: < 12 months)					
35	Major Emergency Balancing Account	(13,044,602)	95,354,948	182.3	81,071,006	1,239,340
36	(amortization: < 12 Months)					
37	Market Redesign & Technology Memo Account	75,657,530	1,051,924	182.3	75,965,862	743,592
38	(amortization: < 12 months)					
39	Miscellaneous Electric Reg Asset - Current	255,474,365	197,241,982	Various	176,090,065	276,626,282
40	(amortization: < 12 months)					
41	Miscellaneous Electric Reg Asset - NonCurrent	12,783,390	15,151,269	549	25,668,064	2,266,595
42	(amortization: 25 years)					
43	Miscellaneous Gas Reg Asset - Current		24,889,346	173		24,889,346
44	TOTAL	8,666,911,679	25,045,124,039		24,405,351,301	9,306,684,417

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	03/31/2017	End of 2016/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	Mobile Home Park Balancing Account - Electric	2,948,667	2,158,322	182.3	3,228,360	1,878,629
3	(amortization: < 12 months)					
4	Mobile Home Park Balancing Account - Gas	3,008,795	2,468,057	182.3	3,379,811	2,097,041
5	(amortization: < 12 months)					
6	Modified transition cost balancing account	133,385,934	111,617,704	400	254,786,281	-9,782,643
7	(amortization: < 12 months)					
8	Negative Ongoing Competition Transition Chrg BA	2,925,663,080	110,018,802	182.3	29,390,333	3,006,291,549
9	(amortization: < 12 months)					
10	Non Current HSM BA Elec	20,252,500	71,994,897	182.3	56,205,525	36,041,872
11	(amortization: > 12 months)					
12	Non Current HSM BA Gas	47,255,835	167,978,575	182.3	131,136,708	84,097,702
13	(amortization: > 12 months)					
14	Nuclear Decommissioning Adjustment Mechanism	(8,792,542)	108,849,501	400	81,562,559	18,494,400
15	(amortization: 2 years)					
16	Nuclear Regulatory Commission Rulemaking Costs BA	(15,024,917)	38,029,192	182.3	34,574,584	-11,570,309
17	(amortization: > 12 Months)					
18	Pension Regulatory Asset	2,413,623,146	45,828,546	926	30,704,360	2,428,747,332
19	(amortization: indefinite)					
20	Procurement Energy Efficiency Rev. Adj. Mechanism	848,491	243,216,333	400	268,277,105	-24,212,281
21	(amortization: < 12 months)					
22	Public Purpose Programs Revenue Adjustment Mech.	(17,225,720)	217,176,797	400	209,574,233	-9,623,156
23	(amortization: < 12 months)					
24	Purchased Gas Balancing Account	(1,819,420)	1,881,884,975	400	1,878,037,179	2,028,376
25	(amortization: < 12 months)					
26	Reg Asset - Abandoned Capital Projects		37,992,497	400	25,190,731	12,801,766
27	(amortization: < 12 months)					
28	Reg Asset - Mobilehome park BA - E Noncurrent		9,690,155	597	1,352,430	8,337,725
29	(amortization: < 12 months)					
30	Reg Asset - Mobilehome park BA - G Noncurrent		8,359,990	893	1,378,878	6,981,112
31	(amortization: < 12 months)					
32	Reg Asset - Mobilehome park BA - E Current		717,163	597	137,996	579,167
33	(amortization: < 12 months)					
34	Reg Asset - Mobilehome park BA - G Current		615,369	893	147,108	468,261
35	(amortization: < 12 months)					
36	REGULATORY ASSET-CEMA-ELEC-NONCURRENT	76,810,796	118,766,146	588	51,608,647	143,968,295
37	Amortization : > 12 MONTHS					
38	Reliability Services Balancing Account	6,097,585	5,766,423	400	16,459,589	-4,595,581
39	(amortization: < 12 months)					
40	Renewables Portfolio Standard Cost Memo Acct	326,745	383,209	400	429,680	280,274
41	(amortization: < 12 months)					
42	Residential Rate Reform Memorandum Account (RRRMA)		20,801,363	182.3	10,475	20,790,888
43	(amortization: < 12 months)					
44	TOTAL	8,666,911,679	25,045,124,039		24,405,351,301	9,306,684,417

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	03/31/2017	End of 2016/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	Revised Customer Energy Stmt. BA - Elec.	1,961,782	2,113,374	182.3	2,121,411	1,953,745
2	(amortization: < 12 months)					
3	Revised Customer Energy Stmt. BA - Gas	1,605,093	1,729,125	182.3	1,735,700	1,598,518
4	(amortization: < 12 months)					
5	SMART GRID MEMORANDUM ACCOUNT	5,799,077	890,541	182.3	5,803,922	885,696
6	Amortization : < 12 MONTHS					
7	SmartMeter Opt-Out Program Balancing Account-Electc	7,158,939	5,113,708	182.3	2,099,227	10,173,420
8	(amortization: < 12 Months)					
9	SmartMeter Opt-Out Program Balancing Account-Gas	11,990,650	3,278,424	182.3	117,601	15,151,473
10	(amortization: < 12 Months)					
11	Transition Cost - Noncore Balancing Account	(8,173,947)	114,056,902	400	109,232,413	-3,349,458
12	(amortization: < 12 months)					
13	Transmission Access Charge Balancing Account	111,818,581	453,603,160	400	321,651,053	243,770,688
14	(amortization: < 12 months)					
15	Transmission Integrity Mgmt Balancing Account		317,262,709	400	143,409,876	173,852,833
16	(amortization: > 12 months)					
17	Transmission Revenue Balancing Account	(62,562,477)	133,816,687	400	164,798,597	-93,544,387
18	(amortization: < 12 months)					
19	Unamortized Financial Hedging Cost	14,452,234		428	836,195	13,616,039
20	(amortization: 20 years)					
21	Unamortized Financial Hedging Cost Current	836,195		428		836,195
22	(amortization: < 12 months)					
23	URG Plant Regulatory Asset - current	43,335,000				43,335,000
24	(amortization: < 12 months)					
25	URG Plant Regulatory Asset - noncurrent	943,709,000				943,709,000
26	(amortization: 22 years)					
27	URG Plant Regulatory Asset - Tax	183,010,953				183,010,953
28	(amortization: 11 years)					
29	Vegetation Management Reg. Asset - Current	22,579,554	169,568,629	400	178,347,175	13,801,008
30	(amortization: < 12 months)					
31						
32	Miscellaneous minor items	29,630,310	229,708,560	Various	259,009,012	329,858
33						
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42						
43						
44	TOTAL	8,666,911,679	25,045,124,039		24,405,351,301	9,306,684,417

Schedule Page: 232.1 Line No.: 8 Column: b

The FERC software will not allow the entire beginning balance of Electric Balancing Account Reserve Account of ($3,046,841,305) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 8:	($999,999,999)
Line 9:	($999,999,999)
Line 10:	($999,999,999)
Line 11:	($46,841,308)
Total	($3,046,841,305)

Schedule Page: 232.1 Line No.: 8 Column: f

The FERC software will not allow the entire ending 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 8:	($999,999,999)
Line 9:	($999,999,999)
Line 10:	($999,999,999)
Line 11:	($237,926,773)
Total	($3,237,926,770)

Schedule Page: 232.1 Line No.: 29 Column: a

Primarily internal labor expenses.

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

182.3 - Other Regulatory Assets, 549 - Misc. Other Power Generation Expenses and 253 - Other Deferred Credits.

Schedule Page: 232.4 Line No.: 32 Column: d

Primarily New System Generation Balancing Account and Electric Meters Current Regulatory Asset, 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	03/31/2017	End of 2016/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	-7,435,282	888,781,888	VARIOUS	884,779,018	-3,432,412
2	Customer Adv for Construction	10,261,453	1,162,236	VARIOUS	3,330,370	8,093,319
3	Development Costs	47,684,567	5,709,827	131	930,307	52,464,087
4	Payments for MLX and					
5	Non-Energy Invoices	-984,143	609,796,456	VARIOUS	607,275,299	1,537,014
6	Payments for Main Line					
7	Extension	-3,153,583	136,128,622	VARIOUS	136,881,284	-3,906,245
8	Clearing Account for					
9	JP Morgan Chase	1,850,684	39,699,083	VARIOUS	40,238,328	1,311,439
10	Reimburseable Transmission					
11	Interconnection Study Costs	1,588,657	5,593,298	VARIOUS	5,900,529	1,281,426
12	Interest on Commercial Paper	228,415	5,979,571	431	5,948,596	259,390
13	Payroll Clearing Account	-5,563	11,332,540,871	VARIOUS	11,332,271,383	263,925
14	Miscellaneous minor items	-1,180,864	535,552,707	VARIOUS	534,445,155	-73,312
15						
16						
17						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	48,854,341				57,798,631

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.: 11 Column: d

Typical Accounts charged: 131, 143

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

End of year 2015 balance ($5,563) previously disclosed within the miscellaneous minor items row. End of year 2016 balance exceeds the $100,000 threshold for miscellaneous minor items. As such, payroll clearing is being disclosed separately in 2016.

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

Typical Accounts charged: 131, 232, 241, 520

Schedule Page: 233 Line No.: 14 Column: b

Beginning of year 2016 balance does not include -$5,563 for the payroll clearing account balance that was previously disclosed within the miscellaneous minor items row. The payroll clearing account end of year 2016 balance exceeds the $100,000 threshold for miscellaneous minor items. As such, payroll clearing is being disclosed separately in 2016. See note on line 13, column b.

Schedule Page: 233 Line No.: 14 Column: c

Activity primarily reflects undistributed cash receipts.

Schedule Page: 233 Line No.: 14 Column: d

Typical Accounts charged: 232, 509, 520

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Environmental	-98,264,038	-133,488,724
3	Compensation	31,480,441	52,955,235
4	CIAC	-216,936,608	-200,844,330
5	Injuries and Damages	111,193,926	186,135,579
6	California Corporation Franchise Tax	163,526,064	221,309,584
7	Other	421,346,952	243,478,691
8	TOTAL Electric (Enter Total of lines 2 thru 7)	412,346,737	369,546,035
9	Gas		
10	Environmental	-2,111,272	-53,336,878
11	Compensation	36,989,999	35,556,031
12	CIAC	298,706,854	300,896,855
13	Injuries and Damages	-39,822,402	-82,309,688
14	California Corporation Franchise Tax	-3,868,408	-23,660,612
15	Other	1,069,891,541	1,578,741,423
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,359,786,312	1,755,887,131
17	Other (Specify)	312,153,435	424,027,365
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,084,286,484	2,549,460,531

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	(193,286,134)	(84,916,857)
Compensation	(10,849,994)	3,376,290
Other	516,289,563	505,567,932
Total	312,153,435	424,027,365

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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				
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42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
264,374,809	1,321,874,045					3
						4
264,374,809	1,321,874,045					5
						6
						7
						8
						9
418,291	10,457,275					10
611,142	15,278,550					11
793,031	19,825,775					12
1,778,172	44,454,300					13
934,322	23,358,050					14
						15
						16
						17
4,534,958	113,373,950					18
						19
						20
						21
						22
400,000	10,000,000					23
1,173,163	29,329,075					24
4,211,662	105,291,550					25
						26
5,784,825	144,620,625					27
						28
						29
						30
						31
						32
						33
						34
						35
						36
10,319,783	257,994,575					37
						38
						39
						40
						41
						42

Schedule Page: 250 Line No.: 15 Column: a

Redeemed on August 31, 2005.

Schedule Page: 250 Line No.: 30 Column: a

This was reclassifed to Other Long-Term Debt in accordance with ASC 480 in September 2003. It was shown here since it is still part of the total number of preferred shares authorized. They were fully redeemed on May 31, 2005.

Schedule Page: 250 Line No.: 31 Column: a

This was reclassifed to Other Long-Term Debt in accordance with ASC 480 in September 2003. It was shown here since it is still part of the total number of preferred shares authorized. They were fully redeemed on May 31, 2005.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid in Capital	
2	Equity Infusions from Parent Company	6,229,587,624
3	Excess Tax Benefit on Stock Based Compensation	50,960,304
4		
5		
6		
7		
8		
9		
10		
11		
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39		
40	TOTAL	6,280,547,928

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)		Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221:			
2	SENIOR NOTES & POLLUTION CONTROL BONDS:			
3	Series	Rate		
4	Series 6.05% Senior Notes due 2034	6.050%	3,000,000,000	30,717,515
5				14,640,000 D
6	Series 5.80% Senior Notes due 2037	5.800%	700,000,000	6,807,234
7				3,822,000 D
8	Series 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		16,892,100,000	244,451,390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	1,716,157
33	TOTAL	16,892,100,000	244,451,390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	4,873,854
3				8,415,000 D
4	Series 2.95% Senior Notes due 2026	2.95%	600,000,000	5,255,874
5				1,596,000 D
6	Series 4.00% Senior Notes due 2046	4.00%	400,000,000	3,964,274
7				7,344,000 D
8	Pollution Control Bonds			
9	1996 Series 96C/E/F	Various	465,000,000	5,923,662
10				
11	1997 Series 97B	Various	148,550,000	2,129,592
12				
13	2004 Series A-D	4.750%	345,000,000	7,897,424
14				
15	2008 Series F-G	Various	95,000,000	692,629
16				
17	2009 Series A-B	Various	148,550,000	806,484
18				
19	2009 Series C-D	Various	160,000,000	876,137
20	2010 Series E	2.250%	50,000,000	
21				
22	SUBTOTAL ACCOUNT 221		17,037,100,000	244,451,390
23				
24	ACCOUNT 222:			
25	REACQUIRED BONDS			
26	Pollution Control Bonds			
27				
28	2008 Series F-G	Variable	-95,000,000	
29				
30	2010 Series E	2.25%	-50,000,000	
31				
32	SUBTOTAL ACCOUNT 222		-145,000,000	
33	TOTAL		16,892,100,000	244,451,390

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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
						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	500,000,000	28,125,000	8
						9
3/3/08	11/30/17	3/3/08	11/30/17	200,000,000	11,328,125	10
						11
3/3/08	2/15/38	3/3/08	2/15/38	400,000,000	25,431,250	12
						13
10/21/08	10/15/18	10/21/08	10/15/18	600,000,000	49,570,556	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
				16,732,100,001	775,532,907	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12/1/11	12/15/41	12/1/11	12/15/41	250,000,000	11,272,569	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	9,849,444	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	6,976,111	32
				16,732,100,001	775,532,907	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	03/31/2017	End of 2016/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
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	14,750,000	4
						5
12/1/16	12/1/46	12/1/16	12/1/46	400,000,001	1,333,333	6
						7
						8
5/23/96	11/1/26	5/23/96	11/1/26	465,000,000	1,949,738	9
						10
9/16/97	11/1/26	9/16/97	11/1/26	148,550,000	629,804	11
						12
6/29/04	12/1/23	6/29/04	12/1/23	345,000,000	16,387,500	13
						14
09/22/08	Various	09/22/08	Various	95,000,000		15
						16
9/1/09	11/1/26	9/01/09	11/1/26	148,550,000	620,786	17
						18
9/1/09	12/1/16	09/01/09	12/1/16		458,691	19
4/8/10	11/1/26	4/8/10	11/1/26	50,000,000		20
						21
				16,877,100,001	775,532,907	22
						23
						24
						25
						26
						27
				-95,000,000		28
						29
				-50,000,000		30
						31
				-145,000,000		32
				16,732,100,001	775,532,907	33

Schedule Page: 256 Line No.: 1 Column: c

Items included under column (c) represent original issuance expense, premium or discount on issuance related to outstanding debt which are recoverable through the cost of capital mechanism. Other financing related costs which are also recoverable are reflected on page 232, Other Regulatory Assets (Account 182.3).

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

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

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 2016 true up adjustment.

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: 256.2 Line No.: 4 Column: a

Refer to Note 6 on page 109.3, for CPUC authorization number and date.

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

Refer to Note 6 on page 109.3, for CPUC authorization number and date.

Schedule Page: 256.2 Line No.: 19 Column: a

2009 Series C-D was paid off as of 11/30/2016.

Schedule Page: 256.2 Line No.: 22 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	$775,532,907
Remarketing Costs not included in this page	$ 503,697
Total Interest Expense per page 117	$776,036,604

Schedule Page: 256.2 Line No.: 32 Column: c

Original debt expense amortization costs on reacquired bonds are reported in Account 189 on Form 2 page 260.

Schedule Page: 256.2 Line No.: 32 Column: i

Interest costs and income are netted to zero for bonds outstanding and held in FERC Account 222.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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)	1,401,692,694
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions In Aid of Construction	211,430,959
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	120,346,409
11	Provision for State Income Taxes	-49,835,168
12	Balancing Accounts	-780,580,238
13	Per attached schedule (See page 261-1)	1,446,854,571
14	Income Recorded on Books Not Included in Return	
15	AFUDC - Equity and debt	163,835,603
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Per attached schedule (See page 261-1)	2,692,202,315
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-506,128,691
28	Show Computation of Tax:	
29	Federal Tax Net Income as above $	
30	Tax at 35% for Electric, Non-Utility, and Gas	-177,145,042
31	Other	
32	Add: Tax on FIN 48 Interest	49,511
33	Less: Research & Development Credits	-4,500,000
34	Less: Motor Vehicle Credit	-1,000,000
35	Less: Refundable Fuel Credit	-162,050
36	Specified Liability Loss	-105,273,856
37	Other Adjustments	471,802
38	Reclass tax loss to Deferred	182,645,047
39		
40	Subtotal Tax	-104,914,588
41	FIN 48 Tax Adjustments (Net to Gross)	2,550,000
42	Total Tax	-102,364,588
43		
44	Federal Income Tax Accrual	-102,364,588

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

Annual Report of PACIFIC GAS AND ELECTRIC COMPANY
Year Ended December 31, 2016

Deductions recorded on books not deducted on return:		Tax addback
Executive Compensation		3,038,885
Loss on Reacquired Debt		20,298,595
Compensation Related Adjustments		60,209,253
Bad Debts	$	4,538,286
Meals & Entertainment & Lobbying		14,500,000
Capitalized Interest		81,738,393
Nuclear Fuel expense		125,349,148
GHG Allowances		354,149,011
Property Tax & State Income Tax		119,625,348
Fossil Decommissioning		13,112,538
Penalties		32,337,651
Frement Lease		16,648,217
DOE Settlement		34,063,241
Plant Disallowance		536,649,909
Injuries & Damages		29,905,751
Other		690,343
Total	$	1,446,854,571

Deductions on return not charged against book income:		Tax deduct
Computer Software		(100,089,324)
Cost of removal		(225,834,181)
Reversal of bute Fire Reserve		0
Depreciation adjustment		(774,529,936)
Earnings of Subsidiaries		(98,365)
Section 263A MSCM		(153,039,197)
Repairs		(1,270,371,332)
Environmental Cleanup		(84,961,729)
Gas Hedge Amortization		(7,243,148)
Dividends Paid Deduction		(3,540,000)
Nuclear Decom Trust Book Expense		(72,495,103)
Total	$	(2,692,202,315)

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

See footnote in row 13, column (b)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal - FICA	15,219,561		106,152,622	108,692,746	77,361
2	Federal - Taxes on Income	-47,723,949		-102,364,588	-93,070,446	102,845,511
3	Federal - Unemployment	1,217,650		6,048,787	3,858,442	
4	Federal - Decommisioning			18,444,372	18,444,372	
5						
6	SUBTOTAL FEDERAL	-31,286,738		28,281,193	37,925,114	102,922,872
7						
8	State - Taxes on Income	61,258,569		-38,067,958	-95,986,605	-36,292,795
9	State - Unemployment	-8,080		10,505,044	10,331,576	
10						
11	SUBTOTAL STATE TAXES	61,250,489		-27,562,914	-85,655,029	-36,292,795
12						
13	Ad Valorem property	1,103		380,146,155	399,371,825	19,225,670
14	Other	2,461,129		16,814,019	17,295,234	
15						
16	SUBTOTAL OTHER TAXES	2,462,232		396,960,174	416,667,059	19,225,670
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	32,425,983		397,678,453	368,937,144	85,855,747

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)	
12,756,798		74,098,848			32,053,774	1
45,827,420		-103,711,101			1,346,513	2
3,407,995		4,357,546			1,691,241	3
		18,444,372				4
						5
61,992,213		-6,810,335			35,091,528	6
						7
82,884,420		81,990,553			-120,058,511	8
165,388		7,567,834			2,937,210	9
						10
83,049,808		89,558,387			-117,121,301	11
						12
1,103		284,488,837			95,657,318	13
1,979,914		12,112,819			4,701,200	14
						15
1,981,017		296,601,656			100,358,518	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
147,023,038		379,349,708			18,328,745	41

Schedule Page: 262 Line No.: 1 Column: f

Adjustment reflects a portion of FICA taxes paid on construction work in progress. The amount charged during the year was reduced by the amount capitalized.

Schedule Page: 262 Line No.: 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	32,053,774	0	32,053,774
Federal - Taxes on Income	1,297,002	49,511	1,346,513
Federal - Unemployment	1,691,241	0	1,691,241
Total Federal taxes	35,042,017	49,511	35,091,528
State - Taxes on Income	-101,633,919	-18,424,592	-120,058,511
State - Unemployment	2,937,210	0	2,937,210
Total State	-98,696,709	-18,424,592	-117,121,301
Ad Valorem property	95,305,334	351,984	95,657,318
Other	4,701,200	0	4,701,200
Total Other	100,006,534	351,984	100,358,518

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	108,499,537			411.5	1,647,992	
6							
7							
8	TOTAL	108,499,537				1,647,992	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	10%	22,455,294			411.5	895,000	
12							
13	TOTAL	22,455,294				895,000	
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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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	03/31/2017	End of 2016/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
106,851,545	18		5
			6
			7
106,851,545			8
			9
			10
21,560,294	22		11
			12
21,560,294			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
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			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	165,507,625	143,146,456	125,766,695	105,992,322	145,733,252
2						
3	Deferred Cr - Electric Reserves	41,531,849	182,232,926		1,441,900	42,973,749
4						
5						
6	Deferred Rent	767,414	101	767,413	14,537,652	14,537,653
7						
8	Other	22,615,267	Various	47,813,293	34,208,901	9,010,875
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
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33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	230,422,155		174,347,401	156,180,775	212,255,529

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.: 6 Column: a

FY15 end of year balance ($767,414) previously disclosed within the "Other" line item. End of year 2016 balance exceeds the 5% of ending balance threshold ($10,612,776) for other items. As such, deferred rent is being disclosed separately in 2016.

Schedule Page: 269 Line No.: 8 Column: a

"Other" consists of various other deferred credit amounts with balances of less than 5% of the year end balance. (< 212,255,529 * 5% = 10,612,776)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6	Settlement Regulatory Asset	307		
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	307		
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	307		
18	Classification of TOTAL			
19	Federal Income Tax	307		
20	State Income Tax			
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	8,794,037,209	170,249,493	-53,350,221
3	Gas	2,449,063,624	-10,168,978	-237,890,477
4	Nonutility	223,463,820		
5	TOTAL (Enter Total of lines 2 thru 4)	11,466,564,653	160,080,515	-291,240,698
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	11,466,564,653	160,080,515	-291,240,698
10	Classification of TOTAL			
11	Federal Income Tax	8,978,849,749	125,350,437	-228,054,919
12	State Income Tax	2,487,714,904	34,730,078	-63,185,779
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
					481,250,633	9,498,887,556	2
			24,075,967		265,413,119	2,918,122,275	3
20,922,032	222,049,156				78,478,613	100,815,309	4
20,922,032	222,049,156		24,075,967		825,142,365	12,517,825,140	5
							6
							7
							8
20,922,032	222,049,156		24,075,967		825,142,365	12,517,825,140	9
							10
16,382,917	173,874,745		18,852,594		646,124,581	9,802,035,264	11
4,539,115	48,174,411		5,223,373		179,017,780	2,715,789,872	12
							13

NOTES (Continued)

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

FERC Form 1 Pages 274-275
12/31/16
Detail of Adjustments

	(457,181,666)	SFAS 109 adjustment - account 182.3
	(24,068,967)	Reclass FERC Line of business within account 282
<A>	(481,250,633)	
<B>	($265,413,115)	SFAS 109 adjustment - account 182.3
<D>	(78,478,613)	SFAS 109 adjustment - account 182.3

Schedule Page: 274   Line No.: 5   Column: h

FERC Form 1 Pages 274-275
12/31/16
Detail of Adjustments

<C>	$24,075,967	Reclass FERC Line of business within account 282

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Loss on Reacquired Debt	56,001,889	-5,781,925	-235,841
4	Balancing Accounts	163,804,335	71,252,400	-99,691,321
5	Other	2,071,822	4,759	-5,266,911
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	221,878,046	65,475,234	-105,194,073
10	Gas			
11	Loss on Reacquired Debt	26,546,268	-1,462,254	-158,648
12	Balancing Accounts	252,924,958	-34,176,032	-111,381,473
13				
14	Other	-2,421,918		
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	277,049,308	-35,638,286	-111,540,121
18	OTHER	-194,378,809		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	304,548,545	29,836,948	-216,734,194
20	Classification of TOTAL			
21	Federal Income Tax	281,015,874	23,363,708	-169,712,885
22	State Income Tax	23,532,671	6,473,240	-47,021,309
23	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	03/31/2017	End of 2016/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						50,455,805	3
					-301,314	334,446,742	4
			-301,314			7,644,806	5
							6
							7
							8
			-301,314		-301,314	392,547,353	9
							10
						25,242,662	11
						330,130,399	12
							13
						-2,421,918	14
							15
							16
						352,951,143	17
227	-160,809,419					-33,569,163	18
227	-160,809,419		-301,314		-301,314	711,929,333	19
							20
178	-125,921,203		-235,943		-235,943	600,013,848	21
49	-34,888,216		-65,371		-65,371	111,915,485	22
							23

NOTES (Continued)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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	Affiliate Transaction Fee Memo Account-Current Bt	857,050	182.3	1,351,701	1,777,128	1,282,477
2	(amortization: <12 months)					
3	Affiliate Transfer Fees Account	167,426	182.3	360,548	690,875	497,753
4	(amortization: <12 months)					
5	California Solar Initiative	67,768,490	400	62,351,746	105,334,356	110,751,100
6	(amortization: 5 years)					
7	Demand Response Expenditures Balancing Account	28,275,866	400	44,140,731	65,358,729	49,493,864
8	DREBA Operations Balancing Account - Current	75,826,917	400	71,626,179	34,276	4,235,014
9	Electric Price Risk Management - Current	93,621,115	555	351,164,137	332,206,767	74,663,745
10	Electric Price Risk Management - NonCurrent	168,665,707	555	619,305,989	586,618,806	135,978,524
11	Electric Program Investment Charge Balancing Acct	173,516,004	400	141,874,828	89,808,910	121,450,086
12	Engineering Critical Assessment Bal NC		400	24,030,205	51,800,589	27,770,384
13	(amortization: >12 months)					
14	FAS 143 Regulatory Liability - Nuclear	(999,999,999)	Various			-999,999,999
15	FAS 143 Regulatory Liability - Nuclear	(396,898,660)		410,298,776	321,332,456	-485,864,980
16	FAS 143 Regulatory Liability - Fossil	(122,139,112)	Various	3,122,395		-125,261,507
17	FAS 143 Regulatory Liability - Fossil Decomm	156,230,902	228.4	4,203,130	36,085,000	188,112,772
18	FAS 143 Regulatory Liability-Nuclear Decomm	2,469,600,242	128	359,306,552	496,203,488	2,606,497,178
19	FIN 47 Regulatory Liability	(475,829,525)	Various	171,565,830	89,791,274	-557,604,081
20	Gas PPP Surcharge-RDD	(1,188,555)	400	11,762,808	12,268,324	-683,039
21	(amortization: <12 months)					
22	Gas Price Risk Management - Current	203,629	807	16,968,825	23,309,898	6,544,702
23	GHGRBA - Greenhouse Gas Revenue Subaccount	65,193,887	400	404,651,811	304,274,416	-35,183,508
24	(amortization: <12 months)					
25	GHGRBA - Low Carbon Fuels Stnd Rev Subaccount		400	1,532,404	9,395,124	7,862,720
26	(amortization: <12 months)					
27	GPBA - Greenhouse Gas Revenue Subaccount	58,813,397	400		71,171,794	129,985,191
28	(amortization: <12 months)					
29	GPBA - Low Carbon Fuels Stnd Rev Subaccount		400	305,856	1,662,511	1,356,655
30	(amortization: <12 months)					
31	HSM Insurance Recoveries Reg	1,288,783	Various	19,058,540	20,431,953	2,662,196
32	Miscellaneous Electric Reg Liab - Current	177,959,044	449	157,093,905	173,023,471	193,888,610
33	(amortization: <12 months)					
34	Miscellaneous Electric Reg Liab - NonCurrent	42,515,168	549	2,423,978	9,315,275	49,406,465
35	Miscellaneous Gas Reg Liab - Current	400,000,000	495	420,982,247	26,319,165	5,336,918
36	(amortization: <12 months)					
37	Miscellaneous Gas Reg Liab - NonCurrent	30,356,376	549	2,869,554	1,364,902	28,851,724
38	(amortization: 2 years)					
39	Non Current Reg Liab-CC8 Settlement	51,478,518	108	2,361,833		49,116,685
40	(amortization: 25 Years)					
41	TOTAL	2,606,485,396		4,393,950,376	4,015,252,386	2,227,787,406

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	Non-Tariffed Products and Svcs BA-Electric	156,571	182.3	1,312,046	1,404,324	248,849
2	(amortization: < 12 months)					
3	Non-Tariffed Products and Svcs BA-Gas	128,041	182.3	173,145	248,608	203,504
4	(amortization: < 12 months)					
5	On Bill Financing Balancing Electric	32,761,190	930.2	3,387,619	9,858,260	39,231,831
6	On Bill Financing Balancing Gas	7,191,390	930.2	743,624	2,164,008	8,611,774
7	PPP (PPPLIBA)-Electric	113,949,003	400	60,753,938	96,753,529	149,948,594
8	(amortization: <12 months)					
9	PPP (PPPLIBA)-Gas	11,067,375	400	47,789,213	69,814,786	33,092,948
10	(amortization: <12 months)					
11	PPP Energy Efficiency-Gas	20,964,202	400	10,974,842	240,071	10,229,431
12	PPP Surcharge Energy Efficiency - Gas	(22,589,014)	400	81,014,270	100,712,097	-2,891,187
13	(amortization: <12 months)					
14	PPP Surcharge Low Income - Gas	(17,566,377)	400	70,951,505	79,788,535	-8,729,347
15	(amortization: <12 months)					
16	PPP Surcharge RDD - Current	4,373,013	182.3	11,565,781	11,133,155	3,940,387
17	(amortization: <12 months)					
18	Procurement Energy Efficiency	94,844,116	400	49,997,848	1,090,395	45,936,663
19	Procurement Energy Efficiency Bal Acct Current		400	337,035,815	359,270,964	22,235,149
20	(amortization: <12 months)					
21	Publ Purp Prog Energy Efficiency Bal Acct Current		400	73,679,646	78,871,213	5,191,567
22	(amortization: <12 months)					
23	PVPMA - Current	47,506,545	182.3	47,691,934	27,409,551	27,224,162
24	(amortization: < 12 months)					
25	Reg Liability Gas Risk MGMT - Noncurrent	952,100	807	6,528,446	9,811,663	4,235,317
26	Regulatory Liability Retirement	146,441,390	520	6,995,333	54,628,359	194,074,416
27	(amortization: indefinite)					
28	Self Generation Program - Electric	143,666,285	400	26,166,579	30,481,188	147,980,894
29	Self Generation Program-Gas	27,027,689	400	5,743,883	6,668,737	27,952,543
30	Smart Grid Pilot Deployment Bal Acct Current		400	29,813,309	24,473,328	-5,339,981
31	(amortization: < 12 months)					
32	SW Marketing, Education and Outreach Program BA	3,751,318	400	11,772,672	12,922,865	4,901,511
33	SW Marketing, Education and Outreach Program BA	685,972	400	1,301,642	1,430,224	814,554
34	TAMA - Electric	(12,722,771)	182.3			-12,722,771
35	(amortization: 2 Years)					
36	TAMA - Gas	(59,765,309)	182.3			-59,765,309
37	(amortization: 2 Years)					
38						
39	Miscellanous minor items	(2,620,003)	Various	203,842,778	206,497,039	34,258
40						
41	TOTAL	2,606,485,396		4,393,950,376	4,015,252,386	2,227,787,406

Schedule Page: 278 Line No.: 14 Column: b

The FERC software will not allow the entire beginning balance of FAS 143 Regulatory Liability of ($1,396,898,659) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 14:	($999,999,999)
Line 15:	($396,898,660)
Total	($1,396,898,659)

Schedule Page: 278 Line No.: 14 Column: c

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

Schedule Page: 278 Line No.: 14 Column: f

The FERC software will not allow the ending balance of FAS 143 Regulatory Liability of ($1,485,864,979) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 14:	($999,999,999)
Line 15:	($485,864,980)
Total	($1,485,864,979)

Schedule Page: 278 Line No.: 16 Column: c

Offset to account 108 - Accumulated Depreciation, 182.3 - Other Regulatory Asset, and 230 - ARO - Liability.

Schedule Page: 278 Line No.: 19 Column: c

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

Schedule Page: 278.1 Line No.: 39 Column: c

Primarily Vegetation Manaagement balance account, 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	03/31/2017	End of 2016/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	5,408,907,591	5,031,641,589
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	6,622,244,360	6,511,220,329
5	Large (or Ind.) (See Instr. 4)	1,525,023,120	1,554,743,090
6	(444) Public Street and Highway Lighting	71,522,984	69,774,393
7	(445) Other Sales to Public Authorities	2,630,081	3,097,792
8	(446) Sales to Railroads and Railways	5,980,830	9,747,183
9	(448) Interdepartmental Sales	44,898,176	42,247,495
10	TOTAL Sales to Ultimate Consumers	13,681,207,142	13,222,471,871
11	(447) Sales for Resale	2,996,529	18,093,440
12	TOTAL Sales of Electricity	13,684,203,671	13,240,565,311
13	(Less) (449.1) Provision for Rate Refunds	107,912,349	87,833,615
14	TOTAL Revenues Net of Prov. for Refunds	13,576,291,322	13,152,731,696
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,872,964	6,954,221
17	(451) Miscellaneous Service Revenues	7,485,433	7,974,162
18	(453) Sales of Water and Water Power	3,433,187	3,038,309
19	(454) Rent from Electric Property	87,415,601	95,486,423
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-103,012,106	-138,450,611
22	(456.1) Revenues from Transmission of Electricity of Others	6,593,382	8,453,438
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(400) Balancing Accounts	296,968,335	559,692,075
26	TOTAL Other Operating Revenues	305,756,796	543,148,017
27	TOTAL Electric Operating Revenues	13,882,048,118	13,695,879,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
28,660,730	29,278,920	4,760,209	4,749,484	2
				3
38,213,377	39,848,490	632,578	632,081	4
15,402,877	15,974,630	1,326	1,448	5
351,762	372,243	34,237	34,107	6
17,131	20,371	15	15	7
372,171	365,799	25	25	8
308,929	306,967			9
83,326,977	86,167,420	5,428,390	5,417,160	10
1,740,435	1,813,603		3	11
85,067,412	87,981,023	5,428,390	5,417,163	12
				13
85,067,412	87,981,023	5,428,390	5,417,163	14

Line 12, column (b) includes $ 0 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 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 412,205,699 which was deducted from Line 21 below.

Schedule Page: 300 Line No.: 10 Column: c

Column (c) includes California Department of Water Resources ("DWR") revenues of 284,107,411 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	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.: 17 Column: c

This consists of :

NSF fees and rent charges to customers' refundable deposits	2,614,367
MLX billings to electric residential customers	2,898,025
Reimbursable third-party labor requested on behalf of customers	1,371,275
MLX billings to electric non-residential customers	1,089,031
Miscellaneous (items under $250,000)	1,464
Total	7,974,162

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

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.

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

This consists of :

DWR	(284,107,411)
Reimbursement to the Utility for costs spent on customer projects	61,868,882
Other electric revenues not classified elsewhere	56,755,877
Transition Cost Revenue Account for non-bypassable charges	26,738,172
Reimbursement fees paid to the CPUC based on sales	(20,606,508)
Revenue assigned - base	(17,622,683)
Pass-through franchise fees and uncollectible revenue	17,622,683
Unbilled revenues	13,853,427
Other revenue-damage claim	1,704,044
Fees for customer billing for third party service providers	1,661,466
Recreational Facilities Revenue	1,349,934
MCI rights of way	864,577
Fees for utility energy service contracts	544,704
Reimbursement to the Utility for costs spent on customer billing	442,012
Employee transfer fees	430,880
Miscellaneous (items under $250,000)	49,335
Total	(138,450,611)

The DWR revenues of 284,107,411 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	NOT APPLICABLE				
2					
3					
4					
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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	03/31/2017	End of 2016/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	19,392,978	4,146,790,859	3,374,840	5,746	0.2138
3	EL1 Residential Care Program S	7,076,578	870,521,349	1,174,453	6,025	0.1230
4	E6 Residential Time-of-Use Servic	426,374	86,241,636	92,355	4,617	0.2023
5	EL6 Residential Care Time-of-U	34,662	4,217,578	5,664	6,120	0.1217
6	E7 Time-of-Use	230,086	41,229,446	27,140	8,478	0.1792
7	EL7 Residential Care Program T	23,121	2,627,825	2,596	8,906	0.1137
8	E8 Seasonal Service Option	90,980	16,996,485	6,075	14,976	0.1868
9	EL8 Residential Seasonal Care	13,437	1,401,802	872	15,409	0.1043
10	ETOUA Residential Time-of-Use Ser	133,552	31,314,139	16,194	8,247	0.2345
11	EL-TOUA Residential Care Time-of-	14,805	2,016,301	1,704	8,688	0.1362
12	ETOUB Residential Time-of-Use Ser	50,448	11,310,908	3,764	13,403	0.2242
13	EL-TOUB Residential Care Time-of-	5,282	716,950	393	13,440	0.1357
14	ETOUP Residential Time-of-Use Ser	37,455	6,995,420	6,715	5,578	0.1868
15	EA9 Experimental TOU Service for	6	874	1	6,000	0.1457
16	EB9 Experimental TOU Service for		61			
17	ECLSD		1,924			
18	EVA Residential TOU Service for P	406,412	71,684,962	26,954	15,078	0.1764
19	EVB Residential TOU Service for P	1,222	173,969	399	3,063	0.1424
20	EM Master-Metered Multi-family Se	227,712	45,582,321	16,732	13,609	0.2002
21	EML Multifamily CARE Program - Ma	24,333	2,808,302	166	146,584	0.1154
22	EMTOU Residential Time of Use Ser	1,725	294,629	59	29,237	0.1708
23	ES Multi-family Service	26,641	4,326,883	279	95,487	0.1624
24	ESL Multifamily CARE Program Serv	29,138	4,168,861	318	91,629	0.1431
25	ESR RV Park and Residential Marin	2,306	375,601	26	88,692	0.1629
26	ESRL RV Park and Residential Mari	7,812	1,173,518	77	101,455	0.1502
27	ET Mobilehome Park Service	14,947	2,359,040	246	60,760	0.1578
28	ETL Low-Income Mobile Home	385,681	53,014,191	2,163	178,308	0.1375
29	MIS-RS		-582			
30	SE1 Standby - Individually Metere	8	2,072	2	4,000	0.2590
31	SEM1 Standby - Master-Metered Mul	2,970	519,115	9	330,000	0.1748
32	STOUS INDV Standby - TOU		41,152	12		
33	UNCLASSIFIED	59				
34	Total Residential	28,660,730	5,408,907,591	4,760,208	6,021	0.1887
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	85,067,412	13,684,203,671	5,428,389	15,671	0.1609
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	85,067,412	13,684,203,671	5,428,389	15,671	0.1609

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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	442 Commercial and Industrial Sal					
2	A1 Small General Service	1,224,956	241,847,661	54,301	22,559	0.1974
3	A1F Small General Service	71,778	16,652,431	17,590	4,081	0.2320
4	A1X Small General Service	5,477,603	1,193,824,328	357,298	15,331	0.2179
5	A15 Small General Service	489	277,850	422	1,159	0.5682
6	A6 Time-of-Use	1,305,863	261,167,993	26,084	50,064	0.2000
7	A10 Medium General	8,944,552	1,641,770,344	45,269	197,587	0.1835
8	E19 500 to 999 Kw Demand	13,652,260	1,942,136,659	25,825	528,645	0.1423
9	E20 1000 Kw Demand or More	13,831,222	1,333,346,499	1,012	13,667,215	0.0964
10	E37 1000 Kw Demand or More	532,952	59,266,998	434	1,228,000	0.1112
11	ECLSD		12,121			
12	MIS-RS		-10,359			
13	AG1 Agricultural Power	111,438	32,648,838	6,191	18,000	0.2930
14	AG4 TOU Agricultural Power	1,092,547	290,486,968	52,294	20,892	0.2659
15	AG5 Large TOU Agricultural Power	5,213,886	851,266,590	25,530	204,226	0.1633
16	AGICE Agricultural Internal Combu	265,309	31,483,466	1,708	155,333	0.1187
17	AGR Split-Wk TOU Agricultural Pow	43,882	11,659,673	2,274	19,297	0.2657
18	AGV Short-Pk TOU Agricultural Pow	33,123	8,508,503	1,547	21,411	0.2569
19	OL1 Outdoor Area Lighting Serv	10,710	3,163,235	15,314	699	0.2954
20	SA1 Standby & General Service	50	11,691	6	8,333	0.2338
21	SA6 Standby & Small TOU	9,493	1,414,791	16	593,313	0.1490
22	SA10 Standby & Alt. Rate for Med-	16,825	2,540,777	29	580,172	0.1510
23	SE19 Standby & 500 to 999 Kw	90,020	14,655,015	61	1,475,738	0.1628
24	SE20 Standby & 1000 Kw Demand	1,183,299	141,018,702	93	12,723,645	0.1192
25	SE37 Standby - Med Gen	86,647	10,364,977	5	17,329,400	0.1196
26	STOUP Standby - TOU Primary	11,036	8,451,667	205	53,834	0.7658
27	STOUT Standby - TOU Transformer	405,141	47,653,422	255	1,588,788	0.1176
28	STOUS INDV Standby - TOU	1,166	1,466,851	141	8,270	1.2580
29	TC1 Traffic Control Service					
30	UNCLASSIFIED	7	179,789			25.6841
31	Total Commercial and Industrial	53,616,254	8,147,267,480	633,904	84,581	0.1520
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	85,067,412	13,684,203,671	5,428,389	15,671	0.1609
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	85,067,412	13,684,203,671	5,428,389	15,671	0.1609

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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.
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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	22,442	8,381,645	4,027	5,573	0.3735
3	LS1-B Utility-Owned Street & High	28	7,033	7	4,000	0.2512
4	LS1-C Utility-Owned Street & High	6,902	2,723,955	567	12,173	0.3947
5	LS1-D Utility-Owned Street & High	7,337	2,986,639	982	7,471	0.4071
6	LS1-E Utility-Owned Street & High	16,229	7,572,013	1,690	9,603	0.4666
7	LS1-F Utility-Owned Street & High	7,311	2,675,552	1,629	4,488	0.3660
8	LS2-A Customer-Owned Street & Hig	234,821	35,742,079	9,254	25,375	0.1522
9	LS2-C Customer-Owned Street & Hig	4,290	959,322	483	8,882	0.2236
10	LS3 Cust-Owned Street & Highway L	8,952	1,438,151	1,372	6,525	0.1607
11	LS3F Cust-Owned Street & Highway	4,076	775,069	2,198	1,854	0.1902
12	TC1 Traffic Control Service	38,166	7,979,330	11,444	3,335	0.2091
13	TC1F Traffic Control Service	1,208	282,196	584	2,068	0.2336
14	UNCLASSIFIED					
15	Total Public Street and Highway	351,762	71,522,984	34,237	10,274	0.2033
16						
17	445 Other Sales to Public Authori					
18	Special Contracts	17,131	2,630,081	15	1,142,067	0.1535
19	Total Other Sales to Public Aut	17,131	2,630,081	15	1,142,067	0.1535
20						
21	446 Sales to Railroads and Railwa					
22	Special Contracts	372,171	5,980,830	25	14,886,840	0.0161
23	Total Sales to Railroads and Ra	372,171	5,980,830	25	14,886,840	0.0161
24						
25	448 Interdepartmental Sales	308,929	44,898,176			0.1453
26	Total Interdepartmental Sales	308,929	44,898,176			0.1453
27						
28	Total Sales to					
29	Ultimate Consumers					
30						
31	447 Sales for Resale					
32	Special Contracts	1,740,435	2,996,529			0.0017
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	85,067,412	13,684,203,671	5,428,389	15,671	0.1609
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	85,067,412	13,684,203,671	5,428,389	15,671	0.1609

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 will end December 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	03/31/2017	End of 2016/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RQ Sales:					
2	Silicon Valley Power	RQ	SA 20	0.3	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**

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
1,382	792	32,316		33,108	2
					3
1,739,053		2,960,386	3,035	2,963,421	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
1,740,435	792	2,992,702	3,035	2,996,529	
0	0	0	0	0	
1,740,435	**792**	**2,992,702**	**3,035**	**2,996,529**	

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

Sales represent the Grizzly Power Sale.

Silicon Valley Power was formally the City of Santa Clara.

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

The ETC between PG&E and CCSF terminated on July 1, 2015, pursuant to Section 9.26.2 of the CCSF Interconnection Agreement (IA), Rate Schedule FERC No. 114.

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.

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		
5	(501) Fuel	152,252,947	189,655,735
6	(502) Steam Expenses	108,753	340,423
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	353,868	39,269
11	(507) Rents		
12	(509) Allowances	34,794,578	70,147,327
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	187,510,146	260,182,754
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		7,410
17	(512) Maintenance of Boiler Plant	3,241,313	4,189,830
18	(513) Maintenance of Electric Plant	3,368,157	5,937,595
19	(514) Maintenance of Miscellaneous Steam Plant	9,146,456	2,185,250
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	15,755,926	12,320,085
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	203,266,072	272,502,839
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	3,243,338	
25	(518) Fuel	127,864,758	126,705,233
26	(519) Coolants and Water	26,180,362	31,444,865
27	(520) Steam Expenses	35,905,219	44,671,316
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	1,904,738	2,199,280
31	(524) Miscellaneous Nuclear Power Expenses	190,442,620	155,982,651
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	385,541,035	361,003,345
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	2,436,114	
36	(529) Maintenance of Structures	1,601,877	2,228,588
37	(530) Maintenance of Reactor Plant Equipment	25,149,916	34,566,278
38	(531) Maintenance of Electric Plant	39,946,858	41,314,819
39	(532) Maintenance of Miscellaneous Nuclear Plant	69,409,840	64,002,629
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	138,544,605	142,112,314
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	524,085,640	503,115,659
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	790,683	
45	(536) Water for Power	2,204,783	2,307,985
46	(537) Hydraulic Expenses	1,485,978	1,706,362
47	(538) Electric Expenses	31,172,630	40,092,844
48	(539) Miscellaneous Hydraulic Power Generation Expenses	49,639,261	45,990,538
49	(540) Rents	728,620	805,764
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	86,021,955	90,903,493
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,778,009	
54	(542) Maintenance of Structures	4,666,823	6,735,118
55	(543) Maintenance of Reservoirs, Dams, and Waterways	29,729,070	24,694,303
56	(544) Maintenance of Electric Plant	22,231,376	25,838,644
57	(545) Maintenance of Miscellaneous Hydraulic Plant	8,823,703	11,087,571
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	68,228,981	68,355,636
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	154,250,936	159,259,129

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	294,482	
63	(547) Fuel		
64	(548) Generation Expenses	11,800,149	12,392,031
65	(549) Miscellaneous Other Power Generation Expenses	61,046,007	8,651,839
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	73,140,638	21,043,870
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	96,389	
70	(552) Maintenance of Structures	3,177,937	3,129,265
71	(553) Maintenance of Generating and Electric Plant	16,386,615	8,939,220
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,564,147	26,394,822
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	21,225,088	38,463,307
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	94,365,726	59,507,177
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	4,130,065,916	4,419,716,817
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	357,421,813	329,047,197
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,487,487,729	4,748,764,014
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,463,456,103	5,743,148,818
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,980,822	
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	30,795,325	31,486,251
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	27,257,867	27,818,335
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	10,727,010	10,931,830
93	(562) Station Expenses	5,857,460	7,310,475
94	(563) Overhead Lines Expenses	6,730,256	9,269,289
95	(564) Underground Lines Expenses	1,511,260	2,390,838
96	(565) Transmission of Electricity by Others	15,605,261	15,673,592
97	(566) Miscellaneous Transmission Expenses	87,489,750	71,008,557
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	187,955,011	175,889,167
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,142,072	
102	(569) Maintenance of Structures	702,061	1,279,293
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	22,132,051	35,483,435
108	(571) Maintenance of Overhead Lines	82,198,554	71,803,748
109	(572) Maintenance of Underground Lines	1,055,835	778,027
110	(573) Maintenance of Miscellaneous Transmission Plant	929,615	1,478,822
111	TOTAL Maintenance (Total of lines 101 thru 110)	108,160,188	110,823,325
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	296,115,199	286,712,492

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	15,270,198	15,719,229
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	15,270,198	15,719,229
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)	15,270,198	15,719,229
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	7,084,062	
135	(581) Load Dispatching		
136	(582) Station Expenses	1,811,479	4,320,249
137	(583) Overhead Line Expenses	17,401,186	29,620,496
138	(584) Underground Line Expenses	34,532,949	49,642,215
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	2,306,171	3,964,078
141	(587) Customer Installations Expenses	15,676,650	26,571,529
142	(588) Miscellaneous Expenses	364,723,350	182,496,269
143	(589) Rents		
144	TOTAL Operation (Enter Total of lines 134 thru 143)	443,535,847	296,614,836
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	6,939,456	
147	(591) Maintenance of Structures	5,863,236	4,581,922
148	(592) Maintenance of Station Equipment	24,642,816	33,825,137
149	(593) Maintenance of Overhead Lines	402,984,686	424,992,315
150	(594) Maintenance of Underground Lines	35,303,282	41,800,787
151	(595) Maintenance of Line Transformers	2,132,866	2,949,552
152	(596) Maintenance of Street Lighting and Signal Systems	2,940,424	6,300,405
153	(597) Maintenance of Meters	8,342,960	17,033,078
154	(598) Maintenance of Miscellaneous Distribution Plant	645,145	1,596,466
155	TOTAL Maintenance (Total of lines 146 thru 154)	489,794,871	533,079,662
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	933,330,718	829,694,498
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	6,659,804	
160	(902) Meter Reading Expenses	7,203,896	11,698,199
161	(903) Customer Records and Collection Expenses	153,268,507	173,828,400
162	(904) Uncollectible Accounts	39,526,738	35,171,408
163	(905) Miscellaneous Customer Accounts Expenses	5,647,599	2,095,555
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	212,306,544	222,793,562

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	603,279,583	629,052,968
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	7,869,456	2,470,361
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	611,149,039	631,523,329
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	2,273,279	2,978,856
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	2,273,279	2,978,856
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	358,307,049	313,969,948
182	(921) Office Supplies and Expenses	68,132,813	23,245,746
183	(Less) (922) Administrative Expenses Transferred-Credit	27,399,104	53,445,415
184	(923) Outside Services Employed	205,063,792	200,125,233
185	(924) Property Insurance	15,451,679	16,144,030
186	(925) Injuries and Damages	223,742,232	84,806,973
187	(926) Employee Pensions and Benefits	360,500,184	350,134,384
188	(927) Franchise Requirements	103,106,815	97,921,794
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	8,647	
192	(930.2) Miscellaneous General Expenses	11,392,165	10,058,156
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	1,318,306,272	1,042,960,849
195	Maintenance		
196	(935) Maintenance of General Plant	10,958,561	9,774,832
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	1,329,264,833	1,052,735,681
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	8,863,165,913	8,785,306,465

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

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

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

Of the year end balance, $85,614 relate 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, $7,093 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: b

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

Schedule Page: 320 Line No.: 136 Column: c

Of the end of year balance, $176 relate to energy storage operation per FERC Order 784.

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

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

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

Of the year end balance, $1,000,995 relate to energy storage operation per FERC Order 784.

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

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

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

Of the year end balance, $310,050 relate to energy storage operation per FERC Order 784.

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

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

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

Of the year end balance, $79,709 relate to energy storage operation per FERC Order 784.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	QUALIFYING FACILITIES (QF's)			0.00000	0.00000	
2	RENEWABLES:			0.00000	0.00000	
3	BIOGAS-CITY OF WATSONVILLE	LU		0.00000	0.06710	N/A
4	GAS RECEOVERY SYS. (AMERIAN CYN)	LU		0.00000	0.00000	N/A
5	MONTEREY REGIONAL WATER	LU		0.00000	0.41190	N/A
6	WASTE MANAGEMENT RENEWABLE	LU		0.00000	5.94880	N/A
7	BIOMASS-BURNEY FOREST PRODUCTS	LU		24.00000	29.75740	N/A
8	COLLINS PINE	LU		0.00000	3.21450	N/A
9	DG FAIRHAVEN	LU		16.00000	12.23930	N/A
10	HL POWER	LU		20.00000	25.16370	N/A
11	HUMBOLDT REDWOOD COMPANY	LU		0.00000	19.53630	N/A
12	PACIFIC-ULTRAPOWER CHINESE	LU		19.80000	15.77870	N/A
13	RIO BRAVO FRESNO	LU		23.50000	24.92810	N/A
14	RIO BRAVO ROCKLIN	LU		22.00000	24.84000	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	THERMAL ENERGY DEV. CORP.	LU		0.00000	0.00000	N/A
2	WHEELABRATOR SHASTA	LU		49.68000	43.54920	N/A
3	GEOTHERMAL-AMEDEE GEOTHERMAL	IU		0.00000	0.00000	N/A
4	HYDRO-ARBUCKLE MOUNTAIN HYDRO	LU		0.00000	0.00000	N/A
5	CHARCOAL RAVINE	LU		0.00000	0.00010	N/A
6	DAVID O. HARDE	LU		0.00000	0.00000	N/A
7	EAGLE HYDRO	LU		0.00000	0.00000	N/A
8	EIF HAYPRESS LLC LWR	LU		0.00000	3.07150	N/A
9	EIF HAYPRESS LLC MDL	LU		0.00000	3.31470	N/A
10	EL DORADO MONTGOMERY CREEK	LU		0.00000	2.11920	N/A
11	ERIC AND DEBBIE WATTENBURG	LU		0.00000	0.08720	N/A
12	FAR WEST POWER CORPORATION	LU		0.00000	0.00000	N/A
13	FIVE BEARS HYDROELECTRIC	LU		0.00000	0.37610	N/A
14	HAT CREEK HEREFORD RANCH	LU		0.00000	0.01010	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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	HUMBOLDT BAY MWD	LU		0.00000	0.90070	N/A
2	HYDRO PARTNERS CLOVER CREEK	IU		0.00000	0.65360	N/A
3	HYDRO SIERRA DEADWOOD CREEK	LU		0.00000	0.90450	N/A
4	HYPOWER INC.	LU		0.00000	9.76680	N/A
5	INDIAN VALLEY	IU		0.00000	1.24970	N/A
6	JAMES B. PETER	LU		0.00000	0.01360	N/A
7	JAMES CRANE HYDRO	LU		0.00000	0.00060	N/A
8	JOHN NEERHOUT JR.	LU		0.00000	0.00710	N/A
9	KINGS RIVER HYDRO	LU		0.00000	0.34020	N/A
10	LASSEN STATION HYDRO	LU		0.00000	0.99240	N/A
11	LOFTON RANCH	LU		0.00000	0.09630	N/A
12	MADERA CANAL 1174 + 84	LU		0.00000	0.23960	N/A
13	MADERA CANAL 1923	LU		0.00000	0.24010	N/A
14	MADERA CANAL STATION 1302	LU		0.00000	0.05540	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	03/31/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	MALACHA HYDRO L.P.	LU		0.00000	20.82950	N/A
2	MEGA RENEWABLES BIDWELL DITCH	LU		0.00000	1.31810	N/A
3	MEGA RENEWABLES HATCHET CREEK	LU		0.00000	4.49560	N/A
4	MEGA RENEWABLES ROARING CREEK	LU		0.00000	1.21400	N/A
5	MEGA RENEWABLES SILVER SPRINGS	LU		0.00000	0.22600	N/A
6	NELSON CREEK POWER	LU		0.00000	0.58980	N/A
7	NID BOWMAN HYDROELECTRIC	LU		0.00000	2.51020	N/A
8	OLCESE WATER DISTRICT	LU		0.00000	2.05070	N/A
9	OLSEN POWER PARTNERS	LU		0.00000	2.84400	N/A
10	ORANGE COVE IRRIGATION DISTRICT	LU		0.00000	0.39090	N/A
11	ROBERT W. LEE	LU		0.00000	0.00000	N/A
12	ROCK CREEK HYDRO, LLC	IU		0.00000	0.05000	N/A
13	ROCK CREEK WATER DISTRICT	LU		0.00000	0.15220	N/A
14	SANTA CLARA VALLEY WATER DIST.	LU		0.00000	0.31970	N/A
	Total					

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
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1	SCHAADS HYDRO	LU		0.00000	0.11390	N/A
2	SNOW MOUNTAIN BURNEY CREEK	LU		0.00000	1.77430	N/A
3	SNOW MOUNTAIN COVE	LU		0.00000	3.53880	N/A
4	SNOW MT. PONDEROSA BAILEY CREEK	LU		0.00000	0.94090	N/A
5	STEVE & BONNIE TETRICK	LU		0.00000	0.00000	N/A
6	STS HYDROPOWER LTD KANAKA	LU		0.00000	0.58510	N/A
7	SUTTER'S MILL SHAMROCK	LU		0.00000	0.09150	N/A
8	SWISS AMERICA	LU		0.00000	0.02630	N/A
9	TKO POWER LLC	IU		0.00000	2.77460	N/A
10	TOM BENNINGHOVEN	LU		0.00000	0.00900	N/A
11	TRI-DAM PWR AUTHORITY	LU		15.00000	12.69920	N/A
12	WRIGHT RANCH HYDROELECTRIC	LU		0.00000	0.00000	N/A
13	YUBA COUNTY WATER AGENCY (FISH	LU		0.13000	0.14600	N/A
14	SOLAR-VILLA SORRISO SOLAR	LU		0.00000	0.00050	N/A
	Total					

PURCHASED POWER (Account 555) (Including power exchanges)

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1	WIND-ALTAMONT POWER LLC (3-4)	LU		0.00000	0.00000	N/A
2	DONALD R. CHENOWETH	LU		0.00000	0.00140	N/A
3	EDF RENEWABLE WINDFARM V, INC (10	LU		0.00000	9.15550	N/A
4	EDF RENEWABLE WINDFARM V, INC (70	LU		0.00000	0.00000	N/A
5	EDF RENEWABLE WINDFARM V, INC (70	LU		0.00000	2.79980	N/A
6	EDF RENEWABLE WINDFARM V, INC (70	LU		0.00000	0.00000	N/A
7	INTERNATIONAL TURBINE RESEARCH	LU		0.00000	12.95270	N/A
8	THERMAL:			0.00000	0.00000	
9	COGEN-1080 CHESTNUT CORP.	LU		0.00000	0.00230	N/A
10	AIRPORT CLUB	LU		0.00000	0.00150	N/A
11	ARDEN WOOD BENEVOLENT ASSOC.	LU		0.00000	0.00020	N/A
12	CALPINE KING CITY COGEN	LU		111.00000	121.12800	N/A
13	CHEVRON RICHMOND REFINERY	LU		0.00000	9.92470	N/A
14	CITY OF MILPITAS	LU		0.00000	0.00290	N/A
	Total					

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1	CROCKETT COGEN	LU		240.00000	238.76100	N/A
2	ECO SERVICES OPERATIONS LLC	LU		0.00000	0.62680	N/A
3	FRESNO COGENERATION PARTNERS, LP	LU		33.00000	22.78400	N/A
4	FRITO-LAY COGEN	LU		0.00000	0.69260	N/A
5	GREATER VALLEJO RECREATION DIST.	LU		0.00000	0.01140	N/A
6	GREENLEAF UNIT 1	LU		49.20000	45.58460	N/A
7	GREENLEAF UNIT 2	LU		49.20000	48.27580	N/A
8	HAYWARD AREA RECREATION AND PARK	LU		0.00000	0.04710	N/A
9	NIHONMACHI TERRACE	LU		0.00000	0.00470	N/A
10	ORINDA SENIOR VILLAGE	LU		0.00000	0.00000	N/A
11	PE KES KINGSBURG LLC	LU		34.50000	28.80080	N/A
12	PE BERKELEY INC	LU		22.47000	25.63920	N/A
13	PHILLIPS 66	LU		0.00000	9.66620	N/A
14	SANGER POWER LLC	LU		38.00000	42.82240	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	SANTA CRUZ COUNTY WATER ST. JAIL	LU		0.00000	0.00020	N/A
2	SATELLITE SENIOR HOMES	LU		0.00000	0.00100	N/A
3	SRI INTERNATIONAL	LU		0.00000	1.93160	N/A
4	STANFORD ENERGY GROUP	LU		0.00000	0.00000	N/A
5	YUBA CITY COGEN	LU		46.00000	46.70820	N/A
6	YUBA CITY RACQUET CLUB	LU		0.00000	0.00280	N/A
7	EOR-AERA ENERGY LLC COALINGA	LU		0.00000	2.91880	N/A
8	AERA ENERGY SOUTH BELRIDGE	LU		0.00000	1.06130	N/A
9	BERRY PETROLEUM CO - TANNEHILL	LU		0.00000	12.22930	N/A
10	CHEVRON MCKITTRICK	LU		0.00000	4.32770	N/A
11	CHEVRON USA COALINGA	LU		0.00000	3.65470	N/A
12	CHEVRON USA CYMRIC	LU		0.00000	6.04210	N/A
13	CHEVRON USA INC EASTRIDGE	LU		0.00000	17.85600	N/A
14	CHEVRON USA INC SE KERN RIVER	LU		0.00000	8.65440	N/A
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1	CHEVRON USA TAFT/CADET	LU		0.00000	2.50130	N/A
2	COALINGA COGENERATION	LU		37.70000	37.10550	N/A
3	FREEPORT MCMORAN DOME	LU		0.00000	1.94570	N/A
4	MIDSET COGEN CHP	LU		34.70000	37.22500	N/A
5	SALINAS RIVER COGEN CHP	LU		34.70000	38.05450	N/A
6	SARGENT CANYON COGEN	LU		33.50000	37.12200	N/A
7	WESTERN POWER & STEAM INC	LU		17.75000	18.58230	N/A
8						
9						
10						
11						
12	BILATERALS			0.00000	0.00000	
13	2041 ALVARES PRISTINE SUN			0.00000	0.00000	
14	2056 JARDINE PRISTINE SUN LLC			0.00000	0.00000	
	Total					

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(Including power exchanges)

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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	2065 ROGERS PRISTINE SUN FUND 5 LLC			0.00000	0.00000	
2	2094 BUZZELLE PRISTINE SUN LLC			0.00000	0.00000	
3	2096 COTTON PRISTINE SUN LLC			0.00000	0.00000	
4	2097 HELTON PRISTINE SUN, LLC			0.00000	0.00000	
5	2102 CHRISTENSEN PRISTINE SUN			0.00000	0.00000	
6	2103 HILL PRISTINE SUN LLC			0.00000	0.00000	
7	2113 FITZJARRELL PRISTINE SUN			0.00000	0.00000	
8	2125 JARVIS PRISTINE SUN			0.00000	0.00000	
9	2127 HARRIS PRISTINE SUN LLC			0.00000	0.00000	
10	2158 STROING PRISTINE SUN FUND 5 LLC			0.00000	0.00000	
11	2184 GRUBER (ENERPARC)			0.00000	0.00000	
12	2192 RAMIREZ (Oroville Solar)			0.00000	0.00000	
13	2192 RAMIREZ PRISTINE SUN 6			0.00000	0.00000	
14	ABEC BIDART OLD RIVER			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	03/31/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	ABEC BIDART-STOCKDALE LLC			0.00000	0.00000	
2	AGUA CALIENTE SOLAR, LLC			0.00000	0.00000	
3	ALAMO SOLAR			0.00000	0.00000	
4	ALAVI			0.00000	0.00000	
5	ALGONQUIN SKIC 20 SOLAR, LLC			0.00000	0.00000	
6	ALPAUGH 50, LLC			0.00000	0.00000	
7	ALPAUGH NORTH, LLC			0.00000	0.00000	
8	APEX 646-460			0.00000	0.00000	
9	ARLINGTON WIND POWER PROJECT			0.00000	0.00000	
10	ATWELL ISLAND			0.00000	0.00000	
11	AV SOLAR RANCH ONE			0.00000	0.00000	
12	BADGER CREEK LIMITED CHP RFO-2			0.00000	0.00000	
13	BAKER CREEK HYDROELECTRIC			0.00000	0.00000	
14	BAKERSFIELD 111 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	03/31/2017	End of 2016/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	BAP POWER GROUP			0.00000	0.00000	
2	BEAR CREEK SOLAR LLC			0.00000	0.00000	
3	BEAR MOUNTAIN LIMITED (2013 CHP			0.00000	0.00000	
4	BIG CREEK WATER WORKS, LTD.			0.00000	0.00000	
5	BLACKSPRING RIDGE 1A			0.00000	0.00000	
6	BLACKSPRING RIDGE 1B			0.00000	0.00000	
7	BLAKE'S LANDING FARMS, INC			0.00000	0.00000	
8	BONNEVILLE POWER ADMINSTRATION			0.00000	0.00000	
9	BPA TRANSMISSION			0.00000	0.00000	
10	BROWNS VALLEY IRRIGATION DISTRICT			0.00000	0.00000	
11	BUCKEYE HYDROELECTRIC PROJECT			0.00000	0.00000	
12	BUCKEYE HYDROELECTRIC PROJECT			0.00000	0.00000	
13	BUENA VISTA ENERGY, LLC			0.00000	0.00000	
14	CALAVERAS PUBLIC UTILI. DIST. 1			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	CALAVERAS PUBLIC UTILI. DIST. 2			0.00000	0.00000	
2	CALAVERAS PUBLIC UTILI. DIST. 3			0.00000	0.00000	
3	CALPINE DELTA ENERGY CENTER			0.00000	0.00000	
4	CALPINE ENERGY - AGNEWS, INC			0.00000	0.00000	
5	Calpine Energy - EEI			0.00000	0.00000	
6	Calpine Energy - WSPP			0.00000	0.00000	
7	Calpine Energy Services, LP			0.00000	0.00000	
8	CALPINE GEYSERS (200/425 MW)			0.00000	0.00000	
9	CALPINE GEYSERS RETAINED ASSET			0.00000	0.00000	
10	CALPINE LOS ESTEROS UPGRADE			0.00000	0.00000	
11	CALPINE PEAKERS			0.00000	0.00000	
12	CALPINE RUSSELL CITY - COD JUNE 2010			0.00000	0.00000	
13	CALRENEW-1 LLC			0.00000	0.00000	
14	CAMS-DOUBLE C LIMITED			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	03/31/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	CAMS-HIGH SIERRA LIMITED			0.00000	0.00000	
2	CAMS-KERN FRONT LIMITED			0.00000	0.00000	
3	CASTELANELLI BROS BIOGAS			0.00000	0.00000	
4	CASTOR SOLAR PROJECT			0.00000	0.00000	
5	CED LOST HILLS SOLAR			0.00000	0.00000	
6	CED WHITE RIVER SOLAR 2, LLC			0.00000	0.00000	
7	CED WHITE RIVER SOLAR, LLC			0.00000	0.00000	
8	CEDAR FLAT (Shamrock Utilities)			0.00000	0.00000	
9	CHALK CLIFF LIMITED (2013 CGO FRO-2)			0.00000	0.00000	
10	CHALK CLIFF LIMITED (2013 CHP RFO-2)			0.00000	0.00000	
11	CID SOLAR, LLC			0.00000	0.00000	
12	CLARKSVILLE ENERGY			0.00000	0.00000	
13	CLOVER FLAT LFG			0.00000	0.00000	
14	CLOVER LEAF (Shamrock Utilities)			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	CLOVERDALE SOLAR 1, LLC			0.00000	0.00000	
2	COLUMBIA SOLAR ENERGY, LLC			0.00000	0.00000	
3	COPPER MOUNTAIN 10			0.00000	0.00000	
4	COPPER MOUNTAIN SOLAR 2 (SEMPRA)			0.00000	0.00000	
5	COPPER MOUNTAIN SOLAR 48			0.00000	0.00000	
6	CORAM BRODIE WIND			0.00000	0.00000	
7	CORCORAN SOLAR			0.00000	0.00000	
8	DESERT CENTER SOLAR FARM			0.00000	0.00000	
9	DIGGER CREEK HYDRO			0.00000	0.00000	
10	DTE STOCKTON			0.00000	0.00000	
11	Dynegy Moss Landing			0.00000	0.00000	
12	ECOS ENERGY LLC KETTLEMAN SOLAR			0.00000	0.00000	
13	EIF PANOCHE (FIREBAUGH)			0.00000	0.00000	
14	EL DORADO IRRIGATION			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	03/31/2017	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Elk Hills Power LLC			0.00000	0.00000	
2	ENERPARC CA1, LLC			0.00000	0.00000	
3	Eqqus Energy Group			0.00000	0.00000	
4	EURUS (AVENAL PARK, LLC)			0.00000	0.00000	
5	EURUS (SAND DRAG, LLC)			0.00000	0.00000	
6	EURUS (SUN CITY PROJECT, LLC)			0.00000	0.00000	
7	Exelon			0.00000	0.00000	
8	EXELON GENERATION			0.00000	0.00000	
9	EXELON REC SALE 2016			0.00000	0.00000	
10	FALL RIVER MILLS A (ACHOMAWI)			0.00000	0.00000	
11	FALL RIVER MILLS B (AHJUMAWI)			0.00000	0.00000	
12	FPLE DIABLO WINDS			0.00000	0.00000	
13	FRESH AIR ENERGY IV, LLC-SONORA 1			0.00000	0.00000	
14	FRESNO SOLAR SOUTH			0.00000	0.00000	
	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	FRESNO SOLAR WEST			0.00000	0.00000	
2	GASNA			0.00000	0.00000	
3	GAS TRANSPORT ASSOC WITH PANOCHE			0.00000	0.00000	
4	GAS TRANSPORT ASSOC. WITH MARSH			0.00000	0.00000	
5	GENESIS SOLAR, LLC			0.00000	0.00000	
6	Genon Energy, Inc			0.00000	0.00000	
7	GENON- PITTS 5,6,7 (2011-2015)			0.00000	0.00000	
8	GLOBAL AMPERSAND, CHOWCHILLA			0.00000	0.00000	
9	GLOBAL AMPERSAND, EL NIDO			0.00000	0.00000	
10	GOOSE VALLEY HYDRO			0.00000	0.00000	
11	GREEN LIGHT ENERGY - SIRUIS SOLAR			0.00000	0.00000	
12	GREEN LIGHT PEACOCK SOLAR PROJ			0.00000	0.00000	
13	GREEN LIGHT SIRIUS SOLAR			0.00000	0.00000	
14	GWF HANFORD 2013-2022			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	03/31/2017	End of 2016/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	GWF HENRIETTA 2013-2022			0.00000	0.00000	
2	GWF TRACY REPOWERING PPA			0.00000	0.00000	
3	HALKIRK I WIND PROJECT			0.00000	0.00000	
4	HATCHET RIDGE WIND LLC			0.00000	0.00000	
5	HENRIETTA SOLAR			0.00000	0.00000	
6	HIGH PLAINS RANCH II			0.00000	0.00000	
7	HIGH PLAINS RANCH III			0.00000	0.00000	
8	HOLLISTER SOLAR ECOS ENERGY			0.00000	0.00000	
9	IBERDROLA KLONDIKE (AKA PPM			0.00000	0.00000	
10	IBERDROLA RENEWABLES (AKA PPM			0.00000	0.00000	
11	ICE			0.00000	0.00000	
12	IMMODO LEMOORE			0.00000	0.00000	
13	JACKSON VALLEY IRRIGATION DIST			0.00000	0.00000	
14	JR SIMPLOT			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	03/31/2017	End of 2016/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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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	KEKAWAKA CREEK (STS)			0.00000	0.00000	
2	KENT SOUTH - PV 2			0.00000	0.00000	
3	KERN RIVER COGEN (KRCC)			0.00000	0.00000	
4	KINGSBURG 1 TULARE PV II LLC			0.00000	0.00000	
5	KINGSBURG 2 TULARE PV II LLC			0.00000	0.00000	
6	KINGSBURG 3 TULARE PV II LLC			0.00000	0.00000	
7	KLONDIKE WIND IIIA POWER			0.00000	0.00000	
8	LA JOYA DEL SOL #1 (GASNA 16P, LLC)			0.00000	0.00000	
9	LASSEN STATION			0.00000	0.00000	
10	LIVE OAK LIMITED (2013 CHP FRO-2)			0.00000	0.00000	
11	LOST CREEK 1			0.00000	0.00000	
12	LOST CREEK 2			0.00000	0.00000	
13	Macquarie			0.00000	0.00000	
14	MADERA CHOWCHILLA SITE 1174			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	MADERA CHOWCHILLA SITE 1302			0.00000	0.00000	
2	MADERA CHOWCHILLA SITE 1923			0.00000	0.00000	
3	MADERA CHOWCHILLA SITE 980			0.00000	0.00000	
4	MAMMOTH G1 (ORMAT) - RAM 2			0.00000	0.00000	
5	MAMMOTH G3 (M3 ORMAT) - RAM 1			0.00000	0.00000	
6	MARIPOSA ENERGY, LLC			0.00000	0.00000	
7	MARSH LANDING			0.00000	0.00000	
8	MARTINEZ COGEN LP (TESORO)			0.00000	0.00000	
9	MCCALL			0.00000	0.00000	
10	MCFADDEN HYDROELECTRIC FACILITY			0.00000	0.00000	
11	MCKITTRICK LIMITED (2013 CHP FRO-2)			0.00000	0.00000	
12	MERCED IRRIGATION DISTRICT			0.00000	0.00000	
13	MERCED SOLAR ECOS ENERGY			0.00000	0.00000	
14	MESQUITE SOLAR			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	MIDWAY SUNSET COGENERATION			0.00000	0.00000	
2	MILL SULPHUR CREEK PROJECT			0.00000	0.00000	
3	MISSION SOLAR ECOS ENERGY			0.00000	0.00000	
4	MOJAVE SOLAR			0.00000	0.00000	
5	MONTEZUMA WIND II (NEXTERA)			0.00000	0.00000	
6	MORELOS SOLAR LLC - RAM 3			0.00000	0.00000	
7	Morgan Stanley			0.00000	0.00000	
8	MT. POSO (RED HAWK)			0.00000	0.00000	
9	NDP1 (SUN HARVEST SOLAR, LLC)			0.00000	0.00000	
10	NEVADA IRRIGATION DISTRICT NORTH			0.00000	0.00000	
11	NEVADA IRRIGATION DISTRICT SCOTTS			0.00000	0.00000	
12	NEVADA IRRIGATION DISTRICT SOUTH			0.00000	0.00000	
13	NEVP - NORTH DELIVERY - BU			0.00000	0.00000	
14	NEXTERA DIABLO WINDS			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	NEXTERA MONTEZUMA WIND			0.00000	0.00000	
2	NICKEL 1 (NLH1 SOLAR, LLC)			0.00000	0.00000	
3	NID NORTH COMBIE FIT			0.00000	0.00000	
4	NID SCOTTS FLAT			0.00000	0.00000	
5	NID SOUTH COMBIE FIT			0.00000	0.00000	
6	NID-CHICAGO PARK			0.00000	0.00000	
7	NID-DUTCH FLATS, ROLLINS			0.00000	0.00000	
8	NNN LAND & ENERGY, LLC			0.00000	0.00000	
9	NOBLE AMERICAS			0.00000	0.00000	
10	NORTH SKY RIVER ENERGY CENTER			0.00000	0.00000	
11	NORTH STAR SOLAR			0.00000	0.00000	
12	NRG ALPINE SOLAR			0.00000	0.00000	
13	NRG SOLAR KANSAS SOUTH			0.00000	0.00000	
14	OAK LEAF SOLAR			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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 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	OAKLEY EXECUTIVE LLC			0.00000	0.00000	
2	OAKLEY EXECUTIVE RV AND BOAT			0.00000	0.00000	
3	OLD RIVER ONE LLC - RAM 3			0.00000	0.00000	
4	ORION SOLAR I, LLC			0.00000	0.00000	
5	OROVILLE COGEN			0.00000	0.00000	
6	ORTIGALITA POWER COMPANY LLC			0.00000	0.00000	
7	PACIFICORP TSA			0.00000	0.00000	
8	PCWA - LINCOLN HYDROELECTRIC			0.00000	0.00000	
9	PLACER COUNTY WATER AGENCY			0.00000	0.00000	
10	POTRERO HILLS ENERGY PRODUCERS,			0.00000	0.00000	
11	Powerex Corporation			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	03/31/2017	End of 2016/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)	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	RIVAL POWER			0.00000	0.00000	
5	SALMON CREEK HYDROELECTRIC			0.00000	0.00000	
6	SAN JOSE WATER COMPANY-COX AVE			0.00000	0.00000	
7	SANTA MARIA II LFG POWER PLANT			0.00000	0.00000	
8	Sempra Generation			0.00000	0.00000	
9	SHAFTER SOLAR LLC			0.00000	0.00000	
10	Shell Energy North America (US) LP			0.00000	0.00000	
11	SHILOH I WIND PROJECT LLC			0.00000	0.00000	
12	SHILOH II WIND (AKA ENXCO)			0.00000	0.00000	
13	SHILOH III (ENXCO)			0.00000	0.00000	
14	SHILOH IV			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	03/31/2017	End of 2016/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	SIERRA GREEN ENERGY LLC			0.00000	0.00000	
2	SIERRA PACIFIC INDUSTRIES			0.00000	0.00000	
3	SIERRA PACIFIC INDUSTRIES REC PSA			0.00000	0.00000	
4	SIERRA PACIFIC POWER COMPANY TSA			0.00000	0.00000	
5	SO CAL EDISON			0.00000	0.00000	
6	SOLAR PARTNERS II (IVANPAH UNIT 1)			0.00000	0.00000	
7	SOLAR PARTNERS VIII (IVANPAH UNIT 3)			0.00000	0.00000	
8	SONOMA CLEAN POWER			0.00000	0.00000	
9	SONOMA CLEAN POWER AUTHORITY			0.00000	0.00000	
10	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
11	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
12	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
13	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
14	SOUTH SUTTER WATER DISTRICT			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	03/31/2017	End of 2016/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	STARWOOD POWER MIDWAY, LLC			0.00000	0.00000	
2	SUN HARVEST SOLAR, LLC (NDP1)			0.00000	0.00000	
3	Sunrise Power Company, LLC			0.00000	0.00000	
4	SUNSHINE GAS LANDFILL			0.00000	0.00000	
5	THREE FORKS			0.00000	0.00000	
6	TOPAZ SOLAR FARM			0.00000	0.00000	
7	TORO SLO LANDFILL			0.00000	0.00000	
8	Transalta			0.00000	0.00000	
9	TRANSALTA ENERGY MARKETING US			0.00000	0.00000	
10	TUNNEL HILL HYDRO			0.00000	0.00000	
11	TUNNEL HILL HYDROELECTRIC PROJECT			0.00000	0.00000	
12	TWIN VALLEY HYDRO			0.00000	0.00000	
13	VANTAGE WIND (POWEREX S&F)			0.00000	0.00000	
14	VANTAGE WIND ENERGY LLC			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	VASCO WINDS (NEXTERA)			0.00000	0.00000	
2	VECINO VINEYARDS LLC			0.00000	0.00000	
3	VINTNER SOLAR PROJECT			0.00000	0.00000	
4	WADHAM ENERGY LTD. PART.			0.00000	0.00000	
5	WATER WHEEL RANCH			0.00000	0.00000	
6	WEST ANTELOPE - RAM 1			0.00000	0.00000	
7	WESTERN ANTELOPE BLUE SKY RANCH			0.00000	0.00000	
8	WESTERN ELECTRICITY COORDINATING			0.00000	0.00000	
9	WESTLANDS SOLAR FARMS LLC			0.00000	0.00000	
10	WIND RESOURCE 1 (CALWIND) - RAM 1			0.00000	0.00000	
11	WIND RESOURCE II (CALWIND) - RAM 2			0.00000	0.00000	
12	WOLFSEN BYPASS (AMERICAN ENERGY)			0.00000	0.00000	
13	WOLFSEN BYPASS (CCID)			0.00000	0.00000	
14	WOODLAND BIOMASS			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) 03/31/2017	Year/Period of Report End of 2016/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	WOODMERE SOLAR FARM			0.00000	0.00000	
2	YCWA MINI HYDRO			0.00000	0.00000	
3	YOLO COUNTY GRASSLAND #3			0.00000	0.00000	
4	YOLO COUNTY GRASSLAND #4			0.00000	0.00000	
5						
6	AMP charges			0.00000	0.00000	
7	CP Power			0.00000	0.00000	
8	Energy Connect			0.00000	0.00000	
9	EnerNoc Inc			0.00000	0.00000	
10						
11	Pipeline charges			0.00000	0.00000	
12	Core gas supply			0.00000	0.00000	
13	GTN LLC			0.00000	0.00000	
14	RUBY PIPELINE			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	03/31/2017	End of 2016/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.

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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.

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	WILLIAMS FIELD SERVICES -			0.00000	0.00000	
2	SOUTHERN CA GAS - BU			0.00000	0.00000	
3						
4	Other charges			0.00000	0.00000	
5	Irrigation districts			0.00000	0.00000	
6	Liberty Utilities			0.00000	0.00000	
7	ISO charges for storage cost			0.00000	0.00000	
8	ISO charges (net of storage cost but			0.00000	0.00000	
9	Gas purchases, storage cost & forex			0.00000	0.00000	
10	CARB fees			0.00000	0.00000	
11	Consultancy fees			0.00000	0.00000	
12	Gas Hedges & brokers fees			0.00000	0.00000	
13	RECS from customers			0.00000	0.00000	
14	rounding to tie to SAP system					
	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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
							2
34			989	54		1,043	3
							4
1,174			11,505	3,301		14,806	5
38,255			1,224,264	198,175		1,422,439	6
206,906			13,070,729	5,453,313		18,524,042	7
1,256			71,059			71,059	8
68,707			5,012,851	1,869,137		6,881,988	9
110,136			7,529,271	3,180,048		10,709,319	10
78,355			3,529,379	370,088		3,899,467	11
111,912			9,945,427	2,851,788		12,797,215	12
182,459			11,708,355	5,029,476		16,737,831	13
170,646			15,520,760	5,036,440		20,557,200	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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
331,110			10,089,640	6,063,153		16,152,793	2
							3
							4
1			19	3		22	5
							6
							7
11,623			674,179	176,264		850,443	8
13,187			764,678	211,945		976,623	9
9,661			562,483	107,979		670,462	10
223			12,960	990		13,950	11
							12
536			30,980	3,579		34,559	13
64			1,593	247		1,840	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
6,108			166,408	21,451		187,859	1
3,454			93,405	16,559		109,964	2
3,217			84,522	31,172		115,694	3
51,550			1,405,099	470,729		1,875,828	4
1,998			59,362	18,568		77,930	5
98			2,059	132		2,191	6
5			124	10		134	7
57			2,137	71		2,208	8
1,758			101,953	55,109		157,062	9
2,983			73,888	34,495		108,383	10
657			16,951	4,037		20,988	11
193			11,304	1,725		13,029	12
2			103	36		139	13
26			1,538	255		1,793	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
88,585			5,399,234	2,045,547		7,444,781	1
10,096			274,886	174,468		449,354	2
18,165			445,802	192,673		638,475	3
6,667			164,142	71,159		235,301	4
1,504			38,712	28,311		67,023	5
2,426			64,444	28,832		93,276	6
12,775			433,865	244,141		678,006	7
12,211			707,290	90,884		798,174	8
11,886			312,603	106,220		418,823	9
3,151			90,841	69,476		160,317	10
							11
1,281			74,915	11,076		85,991	12
566			32,891	4,515		37,406	13
1,431			42,541			42,541	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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 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.
546			14,310	2,110		16,420	1
7,188			418,275	61,303		479,578	2
14,444			842,988	149,056		992,044	3
3,519			202,208	57,432		259,640	4
							5
1,307			75,803	10,463		86,266	6
603			35,003	2,996		37,999	7
175			5,059	1,351		6,410	8
3,446			91,014	10,297		101,311	9
67			2,086	225		2,311	10
93,558			2,630,248	2,594,008		5,224,256	11
							12
726			19,228	12,025		31,253	13
4			130	16		146	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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 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.
							1
11			313	36		349	2
21,127			588,532	291,273		879,805	3
							4
6,193			202,097	168,639		370,736	5
							6
22,345			1,287,354	589,048		1,876,402	7
							8
13			416	32		448	9
8			237	26		263	10
2			52	5		57	11
417,734			13,154,200	25,077,168		38,231,368	12
35,463			1,052,624	132,535		1,185,159	13
2			52	3		55	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
1,402,628			42,010,645	50,963,962		92,974,607	1
283			8,562	831		9,393	2
2,937			125,493	7,291,641		7,417,134	3
670			17,513	2,513		20,026	4
135			3,964	284		4,248	5
41,889			1,932,293	9,450,632		11,382,925	6
236,046			6,727,848	9,875,326		16,603,174	7
283			8,074	839		8,913	8
39			1,183	142		1,325	9
							10
25,497			1,036,841	8,913,940		9,950,781	11
195,018			5,785,653	4,649,745		10,435,398	12
26,537			786,656	67,791		854,447	13
120,311			4,149,923	8,392,226		12,542,149	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours 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			3	1
1			13			13	2
7,743			226,853	16,254		243,107	3
							4
13,907			471,802	10,231,062		10,702,864	5
36			985	53		1,038	6
13,094			370,487	66,000		436,487	7
2,965			80,748	12,082		92,830	8
84,972			2,493,819	651,791		3,145,610	9
26,214			1,299,526			1,299,526	10
12,171			353,200	79,289		432,489	11
27,132			786,680	142,971		929,651	12
32,629			963,430	167,172		1,130,602	13
16,141			498,882	98,646		597,528	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
7,344			215,170	48,617		263,787	1
253,933			9,363,503	2,309,669		11,673,172	2
12,093			347,608	70,534		418,142	3
269,879			9,639,968	2,851,859		12,491,827	4
287,547			10,261,948	3,117,713		13,379,661	5
284,522			10,176,715	3,047,572		13,224,287	6
144,033			4,435,185	1,549,701		5,984,886	7
							8
							9
							10
							11
							12
606				90,863		90,863	13
2,669				384,415		384,415	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
605				94,858		94,858	1
1,279				190,562		190,562	2
2,063				311,063		311,063	3
4,085				606,129		606,129	4
2,366				348,001		348,001	5
536				91,316		91,316	6
536				80,851		80,851	7
542				83,848		83,848	8
2,978				417,932		417,932	9
999				147,599		147,599	10
2,947				292,126		292,126	11
36				3,603		3,603	12
687				100,866		100,866	13
10,922				1,613,002		1,613,002	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
485				87,911		87,911	1
748,660				129,723,238		129,723,238	2
52,831				4,552,715		4,552,715	3
					-42,000	-42,000	4
46,058				4,106,775		4,106,775	5
135,225				21,406,492		21,406,492	6
53,119				7,969,182		7,969,182	7
1,920				250,972		250,972	8
207,704				21,288,298		21,288,298	9
41,273				6,487,790		6,487,790	10
620,911				95,792,754		95,792,754	11
3,366			3,903,454	26,810	8,716	3,938,980	12
4,171				370,529		370,529	13
3,467				452,231		452,231	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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)	
					-35,000	-35,000	1
3,766				551,928		551,928	2
8,070			3,903,454	100,112	17,305	4,020,871	3
5,707				522,797		522,797	4
				10,208,616	8,194,529	18,403,145	5
				11,012,308	8,935,654	19,947,962	6
182				14,710		14,710	7
				548,510	-1,071	547,439	8
					6,853	6,853	9
2,215				189,380		189,380	10
168				16,449		16,449	11
1,532				145,064		145,064	12
99,558				5,511,976		5,511,976	13
193				17,447		17,447	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
248				25,197		25,197	1
130				11,930		11,930	2
				328,033		328,033	3
17,027			5,984,566	204,254		6,188,820	4
			1,449,000			1,449,000	5
			1,124,805			1,124,805	6
			15,482,980			15,482,980	7
3,548,414			19,176,000	237,878,881		257,054,881	8
					9,384	9,384	9
139,369			67,220,179	2,075,611		69,295,790	10
142,494			47,121,571	3,495,445		50,617,016	11
789,950			142,847,935	6,066,018		148,913,953	12
9,122				2,278,966		2,278,966	13
10,484			5,116,608	93,823		5,210,431	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
10,662			5,113,562	105,994		5,219,556	1
38,577			5,001,666	349,639		5,351,305	2
1,200				120,825		120,825	3
1,462				192,677		192,677	4
					-3,600,000	-3,600,000	5
53,689				5,159,375		5,159,375	6
53,725				7,915,530		7,915,530	7
1,342				117,972		117,972	8
312			1,158,066	-3,170		1,154,896	9
3,100			2,737,668	5,177	8,750	2,751,595	10
53,484				5,472,576		5,472,576	11
					-45,000	-45,000	12
5,570				496,567	-23,627	472,940	13
753				66,380		66,380	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,260				342,606		342,606	1
41,091				4,050,873		4,050,873	2
19,597				3,148,814		3,148,814	3
373,089				48,477,770		48,477,770	4
100,803				16,462,612		16,462,612	5
289,600				33,057,122		33,057,122	6
51,770				7,497,950		7,497,950	7
683,350				110,461,564		110,461,564	8
3,288				290,891		290,891	9
350,347				48,961,853		48,961,853	10
			972,750			972,750	11
2,526				370,652		370,652	12
375,084			55,880,571	3,012,351		58,892,922	13
61,438				6,233,110		6,233,110	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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 Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
			84,049			84,049	1
3,584				532,290		532,290	2
					4,896	4,896	3
12,783				3,179,998		3,179,998	4
40,294				10,048,168		10,048,168	5
41,996				10,502,789		10,502,789	6
128,295					4,117,818	4,117,818	7
					291	291	8
-79,338				-1,884,509	-640,374	-2,524,883	9
3,844				577,243		577,243	10
3,871				579,186		579,186	11
20,133				1,346,934		1,346,934	12
3,832				539,238		539,238	13
3,231				415,771		415,771	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
3,340				427,407		427,407	1
					-80,000	-80,000	2
				548,415		548,415	3
				133,781		133,781	4
627,256				134,290,161		134,290,161	5
			34,770,000			34,770,000	6
				-2,592		-2,592	7
69,407				7,951,226		7,951,226	8
75,103				8,545,759		8,545,759	9
353				31,991		31,991	10
219				22,046	-30,000	-7,954	11
178				23,044		23,044	12
1				139		139	13
25,541			8,147,186	648,189		8,795,375	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
32,712			8,054,908	766,433		8,821,341	1
312,750			67,532,461	4,057,606		71,590,067	2
				8,759,571	9,277,858	18,037,429	3
293,309				31,400,660		31,400,660	4
43,088				3,442,898		3,442,898	5
566,136				71,124,311		71,124,311	6
109,480				14,780,900		14,780,900	7
3,792				506,183		506,183	8
214,344				12,539,118		12,539,118	9
				4,981,922		4,981,922	10
					100,950	100,950	11
3,925				538,695		538,695	12
799				73,182		73,182	13
574				10,360		10,360	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
12,882				883,796		883,796	1
53,745				4,686,229		4,686,229	2
661,393			22,484,978	18,339,697	310,187	41,134,862	3
3,016				420,534		420,534	4
3,048				425,039		425,039	5
1,478				206,298		206,298	6
219,404				17,853,508		17,853,508	7
3,140				408,610		408,610	8
836				75,838		75,838	9
10,305			3,889,922	64,154	26,707	3,980,783	10
4,083				406,514		406,514	11
2,111				211,619		211,619	12
					3,222	3,222	13
119				10,900		10,900	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
126				11,582		11,582	1
125				11,465		11,465	2
3,828				340,121		340,121	3
59,434				5,149,313		5,149,313	4
86,880				7,829,953		7,829,953	5
85,022			29,348,618	729,500		30,078,118	6
75,312			118,136,729	2,234,520	5,177	120,376,426	7
127,066			537,371	3,634,446		4,171,817	8
					-10,000	-10,000	9
90				8,016		8,016	10
7,027			3,903,454	-222,495	8,598	3,689,557	11
167,045				6,928,367		6,928,367	12
3,642				472,754		472,754	13
414,747				66,536,069		66,536,069	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
836,490			14,485,539	-1,456,186	320,578	13,349,931	1
2,114				187,111		187,111	2
3,601				470,060		470,060	3
628,895				125,820,189		125,820,189	4
11,476				1,172,064		1,172,064	5
40,698				3,523,154		3,523,154	6
41,304					1,187,026	1,187,026	7
263,431				33,800,304		33,800,304	8
4				376		376	9
1,560				166,590		166,590	10
3,503				327,415		327,415	11
5,405				511,591		511,591	12
					2,085	2,085	13
33,490				1,947,477		1,947,477	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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)	
274,926				27,991,807		27,991,807	1
3,028				403,820		403,820	2
354				34,613		34,613	3
352				26,916		26,916	4
1,972				186,383		186,383	5
160,796				9,823,094		9,823,094	6
165,299				10,497,105		10,497,105	7
					-10,000	-10,000	8
3,493				237,215		237,215	9
459,396				39,936,226		39,936,226	10
151,907				18,629,318		18,629,318	11
175,505				24,423,337		24,423,337	12
52,620				5,328,780		5,328,780	13
					-60,000	-60,000	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
184				19,560		19,560	1
2,341				345,047		345,047	2
51,094				4,397,040		4,397,040	3
30,917				3,950,300		3,950,300	4
138			1,039,989	11,580		1,051,569	5
5				823		823	6
					13,910	13,910	7
1,118				119,858		119,858	8
985,124				41,506,132		41,506,132	9
42,618				5,455,607		5,455,607	10
			711,000			711,000	11
1,057				162,607		162,607	12
549				82,782		82,782	13
2,706				393,916		393,916	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,819				519,148		519,148	1
10,891			8,059,800	162,313		8,222,113	2
59,297				3,528,565		3,528,565	3
					-40,000	-40,000	4
2,758				243,116		243,116	5
208				24,031		24,031	6
4,965				488,856		488,856	7
20,000			22,830		729,717	752,547	8
51,735				4,986,049		4,986,049	9
			147,500			147,500	10
190,480				10,572,856		10,572,856	11
389,026				33,691,387		33,691,387	12
261,593				30,017,765		30,017,765	13
284,097				25,577,070		25,577,070	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours 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)	
107				13,387		13,387	1
303,153				30,471,546		30,471,546	2
					231,600	231,600	3
					19,341	19,341	4
			-30,000			-30,000	5
267,534				42,896,246	50,244	42,946,490	6
259,317				41,733,413	-54,609	41,678,804	7
			6,740,500			6,740,500	8
			-1,000,000			-1,000,000	9
333,551			2,562,906	8,760,595		11,323,501	10
9,188			121,176	280,911		402,087	11
27,722			232,991	901,121		1,134,112	12
99,438			1,314,400	2,656,335	-420,000	3,550,735	13
156				16,631		16,631	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
41,210			13,412,487	738,796	45,372	14,196,655	1
3,937				344,229		344,229	2
			13,126,400			13,126,400	3
129,862				15,403,132		15,403,132	4
7,398				723,549		723,549	5
1,282,093				221,044,238		221,044,238	6
10,662				1,168,137		1,168,137	7
-800					30,123	30,123	8
236,845					8,057,981	8,057,981	9
292				28,673		28,673	10
2,086				207,120		207,120	11
1,816				213,445		213,445	12
				10,415,725		10,415,725	13
250,833				24,588,856		24,588,856	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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)	
232,656				25,107,713		25,107,713	1
68				6,524		6,524	2
4,367				641,192		641,192	3
170,883				17,456,546		17,456,546	4
3,310				291,708		291,708	5
62,046				4,977,489		4,977,489	6
52,606				3,393,103		3,393,103	7
				113,706	9,292	122,998	8
45,751				6,015,012		6,015,012	9
15,776				1,125,367		1,125,367	10
49,499				3,594,346		3,594,346	11
1,074				111,523		111,523	12
33				2,704		2,704	13
191,910				19,420,183		19,420,183	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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.
39,256				2,474,985		2,474,985	1
318				28,731		28,731	2
2,303				283,998		283,998	3
2,296				286,152		286,152	4
							5
							6
			1,477,609	31,992		1,509,601	7
			-382,016			-382,016	8
			3,079,034	98,062		3,177,096	9
							10
							11
							12
					1,883	1,883	13
					10,485,248	10,485,248	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

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)	
					4,432	4,432	1
					2,763	2,763	2
							3
							4
403,604					10,237,060	10,237,060	5
4,526					886,624	886,624	6
					-87,363	-87,363	7
13,115,389					504,954,179	504,954,179	8
					48,643,225	48,643,225	9
					369,269	369,269	10
					324,903	324,903	11
					50,367,586	50,367,586	12
					8,642	8,642	13
					-795	-795	14
43,020,145			971,272,198	2,495,953,579	662,840,139	4,130,065,916	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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	WESTERN AREA POWER			
3	ADMINISTRATION (WAPA)	WAPA	Various	LFP
4	CONTRACT 2207A			
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			

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
227	Various	Various	3	10,259	10,259	3
						4
						5
						6
						7
						8
12	COTP Terminus/Tracy	Various	65	382,673	371,767	9
						10
						11
						12
143	Midway	Various	233	423,686	415,673	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			301	**816,618**	**797,699**	

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
9,469	3,419		12,888	3
				4
				5
				6
				7
				8
4,242,209		-1,000	4,241,209	9
				10
				11
				12
	2,132,285	207,000	2,339,285	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
4,251,678	**2,135,704**	**206,000**	**6,593,382**	

Schedule Page: 328 Line No.: 2 Column: a

Revenue data represent transmission only.

WAPA acts as its own Scheduling Coordinator and, as such, is charged losses by the California Independent System Operator ("CAISO"). The Utility does not have access to the loss data under the CAISO. Further, WAPA is not obligated to provide the Utility with individual schedules. Without these schedules, the Utility cannot determine the revenue or energy attributable to each delivery point.

Billing demand for WAPA and BART is an average of twelve monthly demands.

Other charges represent booking estimate adjustments.

WAPA's contract expired on March 31, 2016.

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

Transmission is provided under the Open Access Tariff,(FERC Electric Tariff Volume No.12), most recently filed in Docket ER13-616-000.

Billing demand for WAPA and BART is an average of twelve monthly demands.

Other charges represent booking estimate adjustments.

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	03/31/2017	End of 2016/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	NOT APPLICABLE				
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	03/31/2017	End of 2016/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					292,849	292,849
3	Pacificorp	OS			14,500,000		289,185	14,789,185
4	Sacramento Municipal							
5	Utility District	OS			7,450			7,450
6	Western Area Power							
7	Administration	OS			2,028			2,028
8	California-Oregon							
9	Intertie	OS					513,749	513,749
10	Other	OS						
11								
12								
13								
14								
15								
16								
	TOTAL				14,509,478		1,095,783	15,605,261

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.: 5 Column: e
Represents payments for lease of transmission capacity.
Schedule Page: 332 Line No.: 7 Column: e
Represents payments for lease of transmission capacity.
Schedule Page: 332 Line No.: 9 Column: g
Represents payments for administrative costs of scheduling services provided by the California Independent Systems Operator (CAISO).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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 / Cost Adjustments	-337,350
7	MCI-PG&E Exchange Rights	691,661
8	Intervenor Compensation	2,187,929
9	Bank Service Fees	3,876,004
10	Write off from miscellaneous reconciliations	17,182
11	Consulting Services, Outside Attorn. Fees, Contracts	6,934,915
12	Union Negotiation Adjustment	-1,581,372
13	Misc. cash receipt (recovery of unclaimed funds)	-43,569
14	Other Tax Adjustments / Settlements / Refunds	-405,553
15	Gift Cards for Fire Relief	114,688
16	Non-PO Credit Memo's	-55,845
17	Other miscellaneous adjustments	-6,525
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	11,392,165

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			2,609,766		2,609,766
2	Steam Production Plant	61,343,727				61,343,727
3	Nuclear Production Plant	243,922,669			38,731,572	282,654,241
4	Hydraulic Production Plant-Conventional	56,671,066			4,752,000	61,423,066
5	Hydraulic Production Plant-Pumped Storage	5,211,992			3,372,000	8,583,992
6	Other Production Plant	41,888,316				41,888,316
7	Transmission Plant	255,044,603				255,044,603
8	Distribution Plant	1,014,504,586				1,014,504,586
9	Regional Transmission and Market Operation					
10	General Plant	16,907,582				16,907,582
11	Common Plant-Electric	149,240,876		210,992,543		360,233,419
12	TOTAL	1,844,735,417		213,602,309	46,855,572	2,105,193,298

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 2014 GRC authorized rates.

The rates used to compute amortization charges for 'Intangible Plant – Electric' (Account 404) are as follows:
EIP30201 Intangible Plant: Franchise 2.17%
EIP30301 Intangible Plant: USBR 0%
EIP30303 Intangible Plant: Software 9%

The rates used to compute amortization charges for 'Common Plant – Electric' (Account 404) are as follows:
CMP30302 Intangible Plant: Software 24.62%
CMP30304 Intangible Plant: Software 6.58%

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 67.54%.

Amortization of the Other Electric Plant (Account 405) - These amortization amounts represent the 2014 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

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		2.17	SQ	23.60
14	303	2,671	3.00			SQ	-13.50
15	Subtotal	116,607					
16							
17	Steam Prod - Fossil						
18	311	112,611	75.00		3.63	L0	20.70
19	312	274,353	50.00		3.70	R1	20.50
20	333						
21	314	256,401	40.00		3.58	R2.5	21.20
22	315	51,279	30.00		3.51	R4	21.60
23	316	28,296	40.00		3.76	L0.5	20.00
24	Subtotal	722,940					
25							
26	Hydraulic Production						
27	331	475,690	100.00	-1.00	1.01	S2.5	12.70
28	332	2,017,137	100.00	-2.00	1.29	S2.5	15.30
29	333	872,985	51.00	-6.00	2.21	R1.5	14.90
30	334	266,682	50.00	-9.00	3.23	R1.5	12.50
31	335	92,563	40.00	-14.00	3.78	R2	12.30
32	336	79,512	65.00	-3.00	2.54	R1.5	10.30
33	Subtotal	3,804,569					
34							
35	Nuclear Prod - Diablo						
36	321	1,048,760	100.00	-1.00	1.02	R1	5.50
37	322	3,491,803	60.00	-1.00	2.60	R1	7.70
38	323	1,167,598	40.00	-1.00	1.44	R3	6.70
39	324	815,101	75.00	-1.00	1.21	R1.5	6.50
40	325	1,121,820	40.00	-2.00	4.76	R4	7.80
41	Subtotal	7,645,082					
42							
43	Other Production						
44	341	210,376	55.00		3.72	R5,R1	21.20
45	342	11,271	50.00		3.73	R5,R1	20.60
46	343	226,089	40.00		3.59	R5,R2.5	21.30
47	344	353,570	27.00		4.27	R5,R2.5,SQ	20.40
48	345	211,827	35.00		3.76	R5,R2.5	21.10
49	346	97,426	26.00		4.12	R5,S0.5,SQ	11.30
50	Subtotal	1,110,559					

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	Transmission						
13	350	255,772	40.00		3.91	R4	19.60
14	352	487,645	65.00	-20.00	1.80	R3	56.20
15	353	5,752,739	45.00	-19.00	2.64	R1.5,S0,R2	35.10
16	354	834,805	75.00	-65.00	2.25	R4,R5	54.20
17	355	1,028,522	52.00	-65.00	2.99	R1.5	41.40
18	356	1,456,558	65.00	-70.00	2.56	R2,R3	48.80
19	357	498,485	65.00		1.52	R4	55.50
20	358	262,449	55.00	-10.00	1.99	R3	43.30
21	359	72,058	60.00	-10.00	1.91	R1.5	49.60
22	Subtotal	10,649,033					
23							
24	Transmission - Diablo						
25	352.01	5,498	61.00	-20.00	1.42	R3,R5	33.00
26	353.01	89,665	43.00	-4.00	2.96	R1.5,R5	26.80
27	Subtotal	95,163					
28							
29	Distribution						
30	361	323,875	55.00	-20.00	2.25	S5	38.40
31	362	3,194,027	40.00	-21.00	2.93	R2.5	26.90
32	363	33,100	1.00		6.63	R2	-3.50
33	364	3,931,993	42.00	-105.00	5.03	R1.5	27.80
34	365	4,492,052	42.00	-108.00	5.21	R2	27.70
35	366	2,760,582	54.00	-40.00	2.91	R4	36.30
36	367	4,320,222	42.00	-43.00	3.08	R3	26.10
37	368	3,164,607	31.00	-7.00	3.56	R2.5,R3	20.10
38	369	3,128,726	45.00	-57.00	3.38	R3,R4	26.20
39	370	1,119,012	20.00	-9.00	5.75	R1.5	14.60
40	371	27,314	40.00			S1	6.70
41	372	895	16.00			S1	-24.50
42	373	220,709	25.00	-23.00	3.99	R0.5,S6,L0,L3	6.50
43	Subtotal	26,717,114					
44							
45	General Plant						
46	390	11,255	40.00	-10.00	2.08	R3	21.60
47	391	12,435	20.00		7.20	SQ	11.00
48	394	118,936	25.00		3.66	SQ	17.60
49	395	14,445	20.00		9.49	SQ	13.70
50	396	271	20.00		6.34	SQ	1.50

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	397	216,837	15.00		5.04	SQ	13.60
13	398	6,632	20.00		13.75	SQ	5.40
14	Subtotal	380,811					
15							
16	General Plant Diablo						
17	391.01	3,890	20.00		5.13	SQ	17.60
18	398.01	11,735	20.00		5.13	SQ	16.80
19	Subtotal	15,625					
20							
21	Total	51,257,503					
22							
23							
24							
25							
26							
27							
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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	03/31/2017	End of 2016/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	5,375,030		5,375,030	
4	Docket# 05000323	3,205,922		3,205,922	
5	General Accrual	-688,800		-688,800	
6					
7	Fees paid for Diablo Canyon Power Plant				
8	for inspection, license renewal, operator				
9	examination in accordance with Part 170				
10	Docket# 05000275	1,868,289		1,868,289	
11	Docket# 05000323	1,549,644		1,549,644	
12	General Accrual	970,200		970,200	
13					
14	Annual fees paid for Diablo Canyon Power Plant				
15	in accordance with Part 171				
16	Docket# 05000275	392,578		392,578	
17	Docket# 05000323	651,470		651,470	
18	General Accrual	-333,900		-333,900	
19					
20	Fees paid for Diablo Canyon Power Plant				
21	for inspection, license renewal, operator				
22	examination in accordance with Part 170				
23	Docket# 05000275	522,747		522,747	
24	Docket# 05000323	430,397		430,397	
25	General Accrual				
26					
27	Fees paid for Diablo Canyon Power Plant				
28	for inspection, license renewal, operator				
29	examination in accordance with Part 170				
30	Docket# 05000275	1,276,758		1,276,758	
31	Docket# 05000323	1,191,269		1,191,269	
32	Docket# 07200026	58,759		58,759	
33	General Accrual	-809,200		-809,200	
34					
35	Fees paid for Diablo Canyon Power Plant				
36	for inspection, license renewal, operator				
37	examination in accordance with Part 170				
38	Docket# 05000275	77,312		77,312	
39	Docket# 05000323	72,474		72,474	
40	General Accrual	345,900		345,900	
41					
42	Annual fees paid for Humbolt Bay Power Plant				
43	in accordance with Part 171 (Docket# 05000133)	190,500		190,500	
44					
45	*All paid to US Nuclear Regulatory Commission				
46	TOTAL	16,347,349		16,347,349	

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
Electric	524	5,375,030					3
Electric	524	3,205,922					4
Electric	524	-688,800					5
							6
							7
							8
							9
Electric	524	1,868,289					10
Electric	524	1,549,644					11
Electric	524	970,200					12
							13
							14
							15
Electric	532	392,578					16
Electric	532	651,470					17
Electric	532	-333,900					18
							19
							20
							21
							22
Electric	532	522,747					23
Electric	532	430,397					24
	532						25
							26
							27
							28
							29
Electric	107	1,276,758					30
Electric	107	1,191,269					31
Electric	107	58,759					32
Electric	107	-809,200					33
							34
							35
							36
							37
Electric	101	77,312					38
Electric	101	72,474					39
Electric	101	345,900					40
							41
							42
Electric	524	190,500					43
							44
							45
		16,347,349					46

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		
7	A2, A3	Customer Energy Services -
8		Cyber Security and Grid Integration
9		
10		
11	A1(e)	Customer Energy Services -
12		California Solar Initiative
13		
14		
15		
16	A3, A1(e)	SmartGrid
17		
18		
19		
20		
21		
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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	03/31/2017	End of 2016/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
142,997,780		408	310,623		1
		456	-170,643		2
		588	136,969,367		3
		926	919,015		4
		908	4,969,418		5
					6
5,028,586		408	16,175		7
		588	4,967,935		8
		926	44,477		9
					10
3,590,580		408	199		11
		456	-2,500,797		12
		908	6,090,592		13
		926	586		14
					15
11,260,711		408	126,718		16
		549	224,253		17
		588	10,540,450		18
		926	369,295		19
		930	-5		20
					21
					22
					23
					24
					25
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					37
					38

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	227,863,553		
4	Transmission	71,425,168		
5	Regional Market			
6	Distribution	128,333,126		
7	Customer Accounts	111,743,802		
8	Customer Service and Informational	77,406,475		
9	Sales	1,355,927		
10	Administrative and General	326,833,790		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	944,961,841		
12	Maintenance			
13	Production	96,301,001		
14	Transmission	23,871,418		
15	Regional Market			
16	Distribution	151,897,417		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	272,069,836		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	324,164,554		
21	Transmission (Enter Total of lines 4 and 14)	95,296,586		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	280,230,543		
24	Customer Accounts (Transcribe from line 7)	111,743,802		
25	Customer Service and Informational (Transcribe from line 8)	77,406,475		
26	Sales (Transcribe from line 9)	1,355,927		
27	Administrative and General (Enter Total of lines 10 and 17)	326,833,790		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,217,031,677		1,217,031,677
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	3,716,809		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	2,462,771		
35	Transmission	76,189,951		
36	Distribution	144,836,458		
37	Customer Accounts	80,688,282		
38	Customer Service and Informational	21,720,113		
39	Sales	4,687,166		
40	Administrative and General	127,012,772		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	461,314,322		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)	74,499		
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	2,127,389		
47	Transmission	67,132,172		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	67,940,140		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	137,274,200		
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,	3,791,308		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	4,590,160		
56	Transmission (Lines 35 and 47)	143,322,123		
57	Distribution (Lines 36 and 48)	212,776,598		
58	Customer Accounts (Line 37)	80,688,282		
59	Customer Service and Informational (Line 38)	21,720,113		
60	Sales (Line 39)	4,687,166		
61	Administrative and General (Lines 40 and 49)	127,012,772		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	598,588,522		598,588,522
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	1,815,620,199		1,815,620,199
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	796,313,890		796,313,890
69	Gas Plant	332,733,155		332,733,155
70	Other (provide details in footnote):	194,201,591		194,201,591
71	TOTAL Construction (Total of lines 68 thru 70)	1,323,248,636		1,323,248,636
72	Plant Removal (By Utility Departments)			
73	Electric Plant	46,774,650		46,774,650
74	Gas Plant	11,630,127		11,630,127
75	Other (provide details in footnote):	210,008		210,008
76	TOTAL Plant Removal (Total of lines 73 thru 75)	58,614,785		58,614,785
77	Other Accounts (Specify, provide details in footnote):			
78	Other Balance Sheet Salaries and Wages	10,215,303		10,215,303
79	Other Non-Operating Salaries and Wages	8,865,230		8,865,230
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	19,080,533		19,080,533
96	TOTAL SALARIES AND WAGES	3,216,564,153		3,216,564,153

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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.
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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.

COMMON UTILITY PLANT IN SERVICE

Acct No.	Description	Balance Beginning of Year	Additions	Retirements	Transfers and Adjustments	Balance End of Year
301	Organization	229,463	5,332,065	0	-3,993,627	1,567,901
302	Franchises/Consents	214,735	0	0	0	214,735
303	Intangible Plant	1,768,491,873	203,377,682	-235,303,170	2,870,380	1,739,436,765
	Total Intangible Plant	1,768,936,071	208,709,747	-235,303,170	-1,123,247	1,741,219,401
389	Land and Land Rights	84,058,695	315,268	0	-1,126,064	83,247,899
390	Structures and Improvements	1,424,057,954	70,641,330	-7,803,310	757,482	1,487,653,456
391	Personal Computer Hardware	114,163,999	10,807,029	-18,868,684	714,431	106,816,775
391	Office Machines	354,853,823	70,997,207	-40,877,242	254,129	385,227,917
391	Office Furniture and Equipment	107,177,209	8,067,929	-6,864,926	38,425	108,418,637
392	Transportation Equipment	955,190,962	182,637,155	-59,207,074	7,896,400	1,086,517,443
393	Stores Equipment	8,301,786	761,499	-389,069	0	8,674,216
394	Tools, Shop, and Garage Equipment	67,165,009	1,184,811	0	0	68,349,820
395	Laboratory Equipment	11,098,342	132	-251,466	0	10,847,008
396	Power Operated Equipment	141,360,984	27,523,811	-2,821,088	0	166,063,707
397	Communication Equipment	1,089,869,134	109,453,425	-45,150,862	-25,253,605	1,128,918,092
398	Miscellaneous Equipment	23,342,793	5,111,644	-1,326,701	0	27,127,736(a)
399	Other Tangible Property	38,425	679	0	-38,425	679
	Total Non-Landed	4,296,620,420	487,186,651	-183,560,422	-15,631,163	4,584,615,486
	Total	6,149,615,186	696,211,666	-418,863,592	-17,880,474	6,409,082,786

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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101 Property Under Capital Leases	18,836,255	0	0	-605,534	18,230,721
101 Plant Purchased/Sold	432,678	0	0	9,830	442,508
Total Common Utility Plant in Service	6,168,884,119	696,211,666	-418,863,592	-18,476,178	6,427,756,015
107 Construction Work in Progress - Common Utility Plt.	276,603,475	-16,391,971	0	59,776,272	319,987,776
Total Common Utility Plant	6,445,487,594	679,819,695	-418,863,592	41,300,094	6,747,743,791

NOTES:
(a) Included in the 12/31/16 FERC account 398 plant balance is $10,821,533 of 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)	6,427,756,015	4,341,461,283	2,086,294,732
Accumulated Provision for Depreciation (a)	2,521,494,357	1,692,679,162	828,815,195

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)	379,794,172	284,488,837	95,305,335

COMMON UTILITY PLANT AND EXPENSES

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Common Utility Plant (a) included in above amount	28,801,093	19,452,952	9,348,141

NOTES:

(a) 2016 allocations are based on the methodology of unbundling Common Plant as approved in the cost separation filing and adopted in the 2014 General Rate Case (GRC).

	Electric	Gas
Common Plant in Service Allocation Factors	67.54%	32.46%
Common Plant Accumulated Depreciation Allocation Factors	67.13%	32.87%

(b) Amounts are based on direct charges. Not included in the total was $351,983 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	222,316,216	149,240,876	73,075,340
Amortization	404	314,304,400	210,992,544	103,311,856
Total		536,620,616	360,233,420	176,387,196

ALLOCATION OF MAINTENANCE EXPENSES OF COMMON UTILITY PLANT BASED ON THE COST SEPARATION ADOPTED BY THE CPUC

Amount Charged	Account 935

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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Description	During Year	Electric	Gas
Maintenance of General Plant	15,211,771	10,958,560	4,253,211

Note: Operation expense data was not available.

CONSTRUCTION WORK IN PROGRESS (CWIP) - COMMON (ACCOUNT 107)

Description of Project		Amount
70027370	SAP DR	17,841,872
7087512	Auburn Regional Consolidation	15,781,092
70029189	CC&B Infrastructure Hardware	12,573,051
7088326	Auburn Regional Consolidation_B	12,235,081
70026300	CC&B DR & 2.4 Upgrade	9,250,763
7087386	VCOC - New Facility	8,681,231
70025382	Estimating Work Management (Cap) - ED	8,553,813
7087687	77 Beale GO - Elec Upgrd (Dist. Sys.)	8,439,227
7085045	215 Market GO - Window Repl	7,901,958
7087505	San Ramon TC - Upgrades	6,411,262
7084411	Concord SC- Repl Pavement & UG Utilities	6,050,533
70031424	Asset Inspection (GD) - CAP	4,549,966
7086705	Verint - Capital	4,471,798
7088705	System: CSO Teller Line Repl Program	4,103,313
7088525	77 Beale GO - Balanced Workplace (9&10)	4,049,224
7090505	Corp Security-Replacement of Legacy CCTV	3,639,444
70028040	Asset Health Solution -Phase 1	3,562,396
7085688	Oakland SC - Asphalt Replacement	3,370,469
70027581	DC Internet Upgrade	3,079,928
70027205	SRM Technical/Functional Upgrade (OASIS)	2,984,290
70030288	Endur P2 Wave 2 RPS SO Tolling	2,962,275
7084408	77 Beale GO - Mech Upgrd (Pumps 1-4)	2,861,380
70030600	Mobility RFP - Cap	2,642,724
7085486	Fresno Thorne Yard - New Facility	2,499,982
70030681	IM:SAP BW Modernization upgrade v7.4 Cap	2,441,385
7087688	Fresno MDC - Upgrades (Racking)	2,404,652
70030464	Online Pipeline Simulator (Cap)	2,394,740
7088967	San Ramon CfC - Wayfinding/Technology	2,394,595
70032004	GT GIS Upgrade - (Cap)	2,233,916
70028024	Remaining EDMS Libraries	2,219,315
70030275	Enterprise Corrective Action Capital	2,196,337

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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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7084485	45 Beale GO - Mech Upgrd (AHU S2/S3)	2,124,947
70026867	Estimating Work Management (Cap) - GD	2,115,405
70029343	Integra Fiber Replace-North Tower to San	2,014,313
70032262	COC ED&M Rel 4 CAP	1,949,043
70030661	Mobile MRAD Platform (GD) Cap	1,915,815
7082866	San Carlos SC - Upgrades (HVAC/Roof)	1,890,121
70031801	CCA Expansion- PHASE 2 Cap	1,880,054
7089806	SFGO - Balanced Workplace	1,846,510
7090825	Corp Security-SIS Replacement-Capital	1,833,490
70032527	Asset Inspection (ED) - CAP	1,804,527
70030383	New IVR Initiatives CAP	1,781,897
70028741	PGEN Linear Asset Management -Capital	1,733,248
70026660	Pole Loading Tool Upgrade with Industry	1,723,030
7089345	Electric Load Forecast	1,717,981
70026620	IT PM Tools Improvement Release 3 - Prim	1,660,759
70029480	EGI SAP Infrastructure ENOS (ph 4) (Cap)	1,656,756
70030841	Windows 10 Upgrade Ph 1 (CAP)	1,617,042
70030766	ODMS P3/P4	1,588,077
70025042	Estimating Work Management (Cap) - GD	1,561,097
70027401	ESOMS Upgrade CAP	1,527,253
7089765	15067-MEMO-AB802-CAP-IT-CHIN	1,417,828
70021400	MobileConnect for ET Compliance	1,396,813
7087511	Antioch SC - New Facility and Upgrades	1,386,210
70030224	SEMS Safety R6 - EO Event Reporting CAP	1,377,928
70030802	ERIM SAP Migration CAP	1,372,383
70032440	HP OM Agent Rollout Business	1,308,002
70029487	2015 Oracle DB_Audit Rem & Data Sec Enh	1,307,859
70028761	RTAC CAP	1,294,667
70031423	Asset Inspection (ET) - CAP	1,290,636
7087531	San Francisco SC - Upgrades (EMAP)	1,250,433
70030481	Customer Care Mainframe Transition - cap	1,246,055
70030942	iSAP 2.0 (Part 1) CAP	1,205,561
70028100	Los Banos Sub Fiber Install-C	1,202,597
70030695	Tufin Upgrade	1,184,872
70028383	CyberSecu-Monitor Security - GTS	1,182,025
70030222	Strategic Absence Management CAP	1,175,739
7087426	Lemoore SC / Coalinga SC - Consolidatn	1,165,826
7088126	SFGO - Repl Carpet (4 Floors)	1,127,121
70030404	Rate Engine Ph2 - Cap	1,125,599
70029481	EGI SAP Infrastructure ENOS (ph 4) (Cap)	1,079,855
70030327	DCPP Replace plant Radio Systems - cap	1,052,336
70028384	CyberSecu-Asset Change Mgmt-Gas Trans C	1,023,300
7083846	Level 3 Lateral Builds	985,914
70030329	DCPP Replace EDMS/RMS/Filenet -cap	949,509
7089865	VCOC-Bldg 5 Gas Operations Back-Up	948,200
70030740	Enterprise Mobile 2016 - CAP	943,368

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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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7090285	Business Applications - FLISR Dashboard	942,455
70031241	Mobile MRAD Platform (ET) CAP	935,226
70031286	Bentley Hardware Upgrade to Tier 2 (Cap)	932,265
7088932	Bill Impact Analysis	928,434
70027221	Replace REMS with OpenEMS	921,017
70031245	Mobile MRAD Platform (GTS) Cap	919,906
70031882	OMAR Work Stream #3 - Phases 1 and 2	902,873
70032528	Mobile MRAD Platform (ED) - CAP	895,455
70030301	Gas Ops Radio System Phase 4	877,985
70029302	Bandwidth Enhancements - Feather	875,782
7086328	Merced SC - New Site/Facility	869,219
7084987	Modesto SC Fiber Build	821,113
7085005	SFGO - Elec Upgrd (Repl 7 ATS)	818,949
70029444	Personnel Risk Assessment Technology	817,618
70030521	FAN Use Case -SCADA #1	812,206
7085907	Webcast Studio	806,939
70027387	LAN Switch Lifecycle Project	796,735
7081328	Replace ISO Metering Stations Routers/Fi	765,033
70031142	IM:AO DBSVR OEM Enhancements CAPITAL	763,624
70031780	AdvApps for Dist Systm Ops (Cap)	762,484
70029346	Wesley Fiber Install	756,271
70031143	IM:AO DBSVR Security Enhancements CAPITA	751,902
7088933	Bill Forecast and Volatility Models	751,044
70022520	Bentley-SAP Integration CAP ET	742,438
70027389	DCPP Unit 2 Power Board Replacement	737,318
7074466	Tracy Sub to Bethany Cmprsr Stn Fbr Bld	735,903
70029809	IO - DWDM Replacement Phase 3 (Northern	717,709
7088089	VCOC - New Facility (IT Infra)_I	687,340
7086212	77 Beale GO - Mech Upgrd(Fans 6-7-11-12)	660,317
7088763	Electric Storage Containers	654,821
70032762	Partner Peering Network (CAP)	649,281
70029807	Taitnet Node Controller Enhancement	648,630
7089247	Brava SW	638,352
70029190	CC&B Infrastructure Labor	632,747
7090331	System - SC Fencing Program	625,012
7085346	77 Beale GO - Upgrades (Lobby)	616,566
70030884	Stockton SC to L3 Access Pt Fiber Build	608,222
7087827	Systemwide: Strong Motion Instrument'n	596,939
7090645	System ETI - Trailer Upgrade Program_C	579,419
70026860	Table Mtn Sub Fiber Install	568,945
7090426	Node Controller	563,683
70029181	CC&B Analysis and Development	563,059
70030561	Data Center Network Consolidation Servic	560,634
70029347	Brentwood MW to Whiskey Slough to SSA to	560,355
7088446	Fresno Thorne Yard - New Facility_S	554,151
70032264	Calculation and Controls Migration - CAP	546,664

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	03/31/2017	End of 2016/Q4

COMMON UTILITY PLANT AND EXPENSES

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7090085	Stockton Regional Ofc - Upgrades (PH2)	545,866
7090065	CI: GRC & Rate Reform Analysis Enhanceme	533,717
70031521	CCA Expansion- PHASE 1 Cap	533,212
70030586	FAN Use Case -SCADA #2	512,907
70029186	CC&B RSS/CDW	503,560
7084985	Templeton SC-Sub Fiber Build	499,527
70032081	ST-Tools - Security Analytics-Infra Ph3	491,784
7088929	Gas Load Forecast and Integration	466,937
70030723	SONET Ring Upgrade A5R6, 9 Network Eleme	461,829
70029808	2016 Fall Release Omar Replacement	455,591
7084473	Vacaville SC - Upgrades (Generator)	455,506
70027582	IO-Datacenter Network Consolidation	449,250
70030460	Bandwidth Capacity Imp - Salinas SC - Me	448,835
70028907	DR - IT Core: SMTP UDN	445,486
7088934	Mainframe Retirement Electric	444,731
7083729	TO Radio System Expansion - Gato Ridge	437,906
70033146	ST - IAM - Priority Apps Integration	429,125
70027383	GRC SCADA Radio	428,938
7090447	SFGO - Upgrades (Lighting)	428,920
7086009	Radio Reliability - Boonville	416,406
70029345	Table Mtn Microwave	406,787
70029122	TO Radio System Crestview	402,570
70030963	IO - TO Radio - VCOC repeater	400,133
70031621	MDS to MDR conversion	392,804
70029407	Radio Reliability - Alcade ET	383,791
7089106	Dublin Ctr - Upgrades	383,309
7084548	Radio Reliability - Point Sur	376,523
70029720	PIT-VoIP	370,009
70030686	FIP - Ukiah	365,383
70029020	ES Cyber Enhance Network Segmentation-H	364,837
70031840	ST- Core Lifecycle -OIM Migration to One	350,985
70030885	Cinnabar SC Fiber Build	348,591
70029187	CC&B Testing	347,504
70032320	CIP011-WP04-A-Titus Class Suite Enforce	346,904
70029184	CC&B Integration	346,613
70032450	Position Description and Attributes	334,671
7088936	CI: Infrastructure Governance & Standard	330,857
70030800	2016 SCADA TELEPROTECTION	328,158
70030721	SONET Ring Upgrade Ring A2R8, 17 Network	328,003
70031260	2016 CISCO ODN lifecycle	327,026
70030588	FAN Use Case - Hydro FAN #2	313,025
70030980	AO Database Security Vulnerability Remed	307,529
7089766	15067-MEMO-AB802-CAP-BUS	293,319
70031024	X2N Satellite Pilot and Production Proje	293,285
70032201	Hitachi Data System Settlement	293,263
7088928	Bill Determinant Forecast and Analytics	292,449

COMMON UTILITY PLANT AND EXPENSES

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7089525 Bill Determinant FCST & Analyt Long Term       290,181
7089129 Reg Proceedings Mgmt- Business Support         288,239
7088931 Time of Use Models                             284,329
70030693    SONET Ring Upgrade A2R15, 11 Network Ele       273,978
70029804    Adtran Tracer MW Radio MW Replacement          273,929
70033349    COC ED&M Rel 5 CAP                             271,806
70031325    Vacaville Fiber Cable Reliability              271,285
70029581    EMS SMP Server Replacement                     268,848
70032660    VGCC-Sacramento Fiber Install                  268,529
70029880    2016 SCADA Terminal Server                     260,431
7086008 Radio Reliability - Rocks Road                 258,387
70030724    2016 NEC MW Radio Lifecycle                    258,266
70031425    Asset Inspection (GTS) - CAP                   258,127
70029409    Radio Reliability - Round Mt                   251,347



                                                     -------------

Subtotal - Projects with more than $250,000
  in actual costs in CWIP, excluding Research,
  Development, & Demonstration jobs                $297,793,096

Aggregate total of projects with less than $250,000 in actual
  costs in Construction Work in Progress, including credits
  representing preliminary billings.

                                                    $22,194,680
                                                   --------------

        TOTAL CWIP - COMMON                        $319,987,776
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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	03/31/2017	End of 2016/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)	86,826,421	118,497,329	177,286,813	530,114,470
3	Net Sales (Account 447)	(3,558,465)	1,574,407	(5,338,030)	(2,960,386)
4	Transmission Rights				
5	Ancillary Services	2,041,553	1,749,584	913,879	5,885,038
6	Other Items (list separately)				
7	Grid Management Charges	12,634,533	13,260,783	15,210,865	53,553,678
8	FERC Fees	1,532,580	1,138,828	1,467,195	5,274,138
9	ISO Congestion				
10	Unaccounted for Energy	(953,451)	5,453,218	2,971,092	12,364,305
11	Congestion Revenue Rights-Hedge	(8,647,028)	(11,396,454)	(10,716,155)	(30,603,399)
12	Congestion Revenue Rights-Auction	647,896	167,578	(2,263,195)	(2,456,598)
13	Convergence Bidding	(571,795)	(669,893)	(475,703)	(1,625,061)
14	Other ISO-related charges:				
15	Minimum Load				
16	Neutrality	2,365,305	(2,226,322)	(15,176)	(47,328)
17	Voltage Support				
18	Other	(907,926)	(574,783)	2,306,736	4,578,642
19	Cost Recovery	(249,449)	120,657	3,684,709	(1,366,548)
20	Inter Day Ahead SC Trade				
21	Inter Real Time SC Trade				
22	Interest	84,415	48,129	28,385	197,591
23	Capacity - Other	(17,043)	506,442	(898,052)	2,185,007
24	DA IFM Credit Allocation	(8,367,556)	(10,423,413)	(14,619,298)	(43,943,537)
25	RT Offset/Allocation	6,919,379	10,907,725	6,696,503	23,081,327
26	Net Purchases for Energy Storage	(14,698)	(104,724)	22,513	(88,379)
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	89,764,671	128,029,091	176,263,081	554,142,960

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year: Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year: Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch					N/A	246,000
2	Reactive Supply and Voltage				848,044	kW-Month	173,849
3	Regulation and Frequency Response				821,813	kW-Month	32,873
4	Energy Imbalance				2,018,489	kWh	201,849
5	Operating Reserve - Spinning				821,813	kW-Month	177,758
6	Operating Reserve - Supplement				821,813	kW-Month	176,320
7	Other		Various	10,305,757		Various	4,420,720
8	Total (Lines 1 thru 7)			10,305,757	5,331,972		5,429,369

Schedule Page: 398 Line No.: 1 Column: b

With the exception of the Utility's contracts with BART and Minnesota Methane (OAT Tarriff) that are 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						
Regulation Service Charge	-	-	-		Flat Charge	0
ISO related AS activities						
Retail/BART ISO Purchases and Sales and Existing Transmission Contracts (ETC) (a)	-	Various	10,305,757	-	Various	4,420,720
Total			10,305,757			4,420,720

(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	03/31/2017	End of 2016/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	13,855	8	1900	10,005	68		70		3,712
2	February	13,519	1	1900	10,252	68		21		3,178
3	March	13,271	10	1900	9,746	63		22		3,441
4	Total for Quarter 1				30,003	199		113		10,331
5	April	13,406	6	2100	9,612	50				3,744
6	May	17,312	31	1900	13,338	70		72		3,832
7	June	18,927	27	1900	14,796	67		70		3,994
8	Total for Quarter 2				37,746	187		142		11,570
9	July	19,823	27	1800	15,451	72		71		4,229
10	August	17,841	17	1800	13,599	68		50		4,124
11	September	18,189	19	1800	13,664	69		70		4,386
12	Total for Quarter 3				42,714	209		191		12,739
13	October	13,939	10	2000	9,554	54		92		3,693
14	November	13,396	28	1900	9,639	69		95		3,593
15	December	13,816	7	1900	10,307	68		94		3,347
16	Total for Quarter 4				29,500	191		281		10,633
17	Total Year to Date/Year				139,963	786		727		45,273

Schedule Page: 400 Line No.: 11 Column: e

Entry was estimated in prior period and is now updated to refelct actuals.

Schedule Page: 400 Line No.: 11 Column: f

Entry was estimated in prior period and is now updated to reflect actuals.

Schedule Page: 400 Line No.: 11 Column: j

Entry was estimated in prior period and is now updated to reflect actuals.

Schedule Page: 400 Line No.: 15 Column: f

Actual data is not available at time of filing. Entry reflects estimated data.

Schedule Page: 400 Line No.: 16 Column: f

Entries here represent Open Access Transmission Tariff Network Service to the Bay Area Rapid Transit District.

Schedule Page: 400 Line No.: 16 Column: g

Entries here represent transmission service to the following Existing Transmission Contract customers:

California Department of Water Resources
City and County of San Francisco
Transmission Agency of Northern California
Western Area Power Administration ("WAPA")

Schedule Page: 400 Line No.: 16 Column: h

Entries here represent transmission service to the following Existing Transmission Contract customers:

California Department of Water Resources
City and County of San Francisco
Transmission Agency of Northern California
Western Area Power Administration ("WAPA")

Schedule Page: 400 Line No.: 16 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	03/31/2017	End of 2016/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: NOT APPLICABLE

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	03/31/2017	End of 2016/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	83,326,977
3	Steam	5,345,268			
4	Nuclear	18,906,954	23	Requirements Sales for Resale (See instruction 4, page 311.)	1,740,435
5	Hydro-Conventional	8,514,128			
6	Hydro-Pumped Storage	860,672	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
7	Other	695,332			
8	Less Energy for Pumping	1,359,241	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	32,963,113	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	43,020,145	27	Total Energy Losses	-9,065,232
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	76,002,180
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	816,618			
17	Delivered	797,699			
18	Net Transmission for Other (Line 16 minus line 17)	18,919			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	76,002,177			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	6,525,070		12,376	8	1900
30	February	5,936,627		12,141	1	1900
31	March	6,333,341		11,802	10	1900
32	April	6,095,725		12,460	6	2100
33	May	6,822,251		16,022	31	1900
34	June	7,630,853		17,406	28	1900
35	July	8,176,793		18,236	27	1800
36	August	8,018,477		16,268	17	1800
37	September	7,210,839		16,657	19	1800
38	October	7,088,100		12,860	10	2000
39	November	6,751,867		12,860	28	1900
40	December	7,235,597		13,261	7	1900
41	TOTAL	83,825,540				

Schedule Page: 401 Line No.: 3 Column: b

This line includes combined cycle plants only. It does not include internal combustion reciprocating engines, which are included on Line 7.

Schedule Page: 401 Line No.: 7 Column: b

This line includes internal combustion reciprocating engines, photo voltaic and Fuel Cells. This includes photo voltaic generation of 505 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") of 14,197,289 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 revenues amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers, priced at the related CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Statement of Income.

Schedule Page: 401 Line No.: 22 Column: b

This includes MWH sales for DWR and DA as discussed in the footnote to Line 10, column b.

Schedule Page: 401 Line No.: 26 Column: b

Data for energy used by the electric department is not separately available but is included on Line 22.

Schedule Page: 401 Line No.: 36 Column: f

This is a revision of the preliminary data previously submitted.

Schedule Page: 401 Line No.: 37 Column: f

This is a revision of the preliminary data previously submitted.

Schedule Page: 401 Line No.: 40 Column: f

Based on preliminary data at time of filing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *DIABLO CANYON 1 & 2* (b)			Plant Name: *Colusa Gen Station* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Outdoor		
3	Year Originally Constructed	1968			2010		
4	Year Last Unit was Installed	1986			2010		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2323.00			711.50		
6	Net Peak Demand on Plant - MW (60 minutes)	2240			657		
7	Plant Hours Connected to Load	8784			6630		
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	1397			25		
12	Net Generation, Exclusive of Plant Use - KWh	18906953877			2909317		
13	Cost of Plant: Land and Land Rights	22726560			7889274		
14	Structures and Improvements	1047639381			114976388		
15	Equipment Costs	6597215246			540073442		
16	Asset Retirement Costs	1646806164			3912557		
17	Total Cost	9314387351			666851661		
18	Cost per KW of Installed Capacity (line 17/5) Including	4009.6373			937.2476		
19	Production Expenses: Oper, Supv, & Engr	3243338			127658		
20	Fuel	127864758			34974777		
21	Coolants and Water (Nuclear Plants Only)	26180362			0		
22	Steam Expenses	35905219			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1904738			4163252		
26	Misc Steam (or Nuclear) Power Expenses	175270493			802992		
27	Rents	0			0		
28	Allowances	0			13900097		
29	Maintenance Supervision and Engineering	2436113			41785		
30	Maintenance of Structures	1601877			1834723		
31	Maintenance of Boiler (or reactor) Plant	25149916			1712707		
32	Maintenance of Electric Plant	39946858			3461959		
33	Maintenance of Misc Steam (or Nuclear) Plant	69409840			1489765		
34	Total Production Expenses	508913512			62509715		
35	Expenses per Net KWh	0.0269			21.4860		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MWH			Mcf		
38	Quantity (Units) of Fuel Burned	2364513	0	0	20103259	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1035250	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	3.410	0.000	0.000
41	Average Cost of Fuel per Unit Burned	53.833	0.000	0.000	3.530	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.657	0.000	0.000	3.410	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.007	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	10241.374	0.000	0.000	7163.000	0.000	0.000

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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
6008			8766			0			7
0			0			0			8
0			0			0			9
0			0			0			10
20			16			0			11
2435951			367743			0			12
5040000			161399			0			13
72348661			67112250			0			14
381397259			149659404			0			15
3004029			1925852			0			16
461789949			218858905			0			17
745.1831			1345.1684			0			18
127658			39166			0			19
28416729			5893561			0			20
0			0			0			21
100732			0			0			22
0			0			0			23
0			0			0			24
3820511			3816386			0			25
1045869			1034931			0			26
0			0			0			27
11938606			2090011			0			28
41785			12819			0			29
194362			305625			0			30
1476492			52121			0			31
26568064			4182946			0			32
4888601			472			0			33
78619409			17428038			0			34
32.2746			47.3919			0.0000			35
Gas			Oil	Gas					36
Mcf			Bbl	Mcf					37
16995443	0	0	2806	3201553	0	0	0	0	38
1037000	0	0	5955928	1036167	0	0	0	0	39
3.440	0.000	0.000	78.160	3.340	0.000	0.000	0.000	0.000	40
3.570	0.000	0.000	78.650	4.030	0.000	0.000	0.000	0.000	41
3.440	0.000	0.000	13.200	3.890	0.000	0.000	0.000	0.000	42
0.030	0.000	0.000	0.120	0.040	0.000	0.000	0.000	0.000	43
7235.000	0.000	0.000	9205.000	9174.000	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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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

									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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(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	03/31/2017	End of 2016/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	03/31/2017	End of 2016/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

(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

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	03/31/2017	End of 2016/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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 1 (b)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1927	1958
4	Year Last Unit was Installed	1927	1958
5	Total installed cap (Gen name plate Rating in MW)	31.00	97.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	105
7	Plant Hours Connect to Load	7,725	7,689
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	132,481,748	331,768,957
13	Cost of Plant		
14	Land and Land Rights	8,352	2,643
15	Structures and Improvements	332,436	3,652,215
16	Reservoirs, Dams, and Waterways	9,541,350	7,023,737
17	Equipment Costs	9,800,966	37,433,363
18	Roads, Railroads, and Bridges	1,122,380	1,015,448
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	20,805,484	49,127,406
21	Cost per KW of Installed Capacity (line 20 / 5)	671.1446	505.4260
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	6,819	17,607
25	Hydraulic Expenses	35,615	70,291
26	Electric Expenses	256,059	446,909
27	Misc Hydraulic Power Generation Expenses	198,916	464,310
28	Rents	8,350	25,768
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	217,794	659,872
31	Maintenance of Reservoirs, Dams, and Waterways	112,167	250,678
32	Maintenance of Electric Plant	179,155	430,427
33	Maintenance of Misc Hydraulic Plant	53,514	51,303
34	Total Production Expenses (total 23 thru 33)	1,068,389	2,417,165
35	Expenses per net KWh	0.0081	0.0073

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 2105 Plant Name: BUTT VALLEY (b)	FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1921
4	Year Last Unit was Installed	1958	1924
5	Total installed cap (Gen name plate Rating in MW)	40.00	73.85
6	Net Peak Demand on Plant-Megawatts (60 minutes)	41	75
7	Plant Hours Connect to Load	8,504	6,664
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	6
12	Net Generation, Exclusive of Plant Use - Kwh	69,224,900	83,007,608
13	Cost of Plant		
14	Land and Land Rights	489,809	367,338
15	Structures and Improvements	3,292,791	5,068,148
16	Reservoirs, Dams, and Waterways	37,425,453	28,830,042
17	Equipment Costs	15,570,370	25,547,189
18	Roads, Railroads, and Bridges	617,106	488,450
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	57,395,529	60,301,167
21	Cost per KW of Installed Capacity (line 20 / 5)	1,434.8882	816.5358
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	20,642	24,767
25	Hydraulic Expenses	21,910	30,932
26	Electric Expenses	325,373	1,068,788
27	Misc Hydraulic Power Generation Expenses	307,090	496,203
28	Rents	1,858	3,389
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	34,514	307,754
31	Maintenance of Reservoirs, Dams, and Waterways	154,783	234,516
32	Maintenance of Electric Plant	152,039	313,495
33	Maintenance of Misc Hydraulic Plant	77,522	186,782
34	Total Production Expenses (total 23 thru 33)	1,095,731	2,666,626
35	Expenses per net KWh	0.0158	0.0321

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 803 Plant Name: DE SABLA (b)	FERC Licensed Project No. 2310 Plant Name: DRUM NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1963	1913
4	Year Last Unit was Installed	1963	1928
5	Total installed cap (Gen name plate Rating in MW)	18.45	49.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	19	54
7	Plant Hours Connect to Load	7,068	4,674
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	6
12	Net Generation, Exclusive of Plant Use - Kwh	49,391,930	154,271,055
13	Cost of Plant		
14	Land and Land Rights	147,468	1,579,742
15	Structures and Improvements	3,098,380	5,436,995
16	Reservoirs, Dams, and Waterways	39,625,676	39,417,982
17	Equipment Costs	5,874,523	17,703,505
18	Roads, Railroads, and Bridges	2,564,160	1,423,750
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	51,310,207	65,561,974
21	Cost per KW of Installed Capacity (line 20 / 5)	2,781.0410	1,332.5604
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	7,891	19,914
25	Hydraulic Expenses	45,038	2,337
26	Electric Expenses	534,794	941,645
27	Misc Hydraulic Power Generation Expenses	548,480	369,052
28	Rents	3,655	17,724
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	81,140	139,199
31	Maintenance of Reservoirs, Dams, and Waterways	827,698	322,782
32	Maintenance of Electric Plant	77,371	300,137
33	Maintenance of Misc Hydraulic Plant	181,941	63,559
34	Total Production Expenses (total 23 thru 33)	2,308,008	2,176,349
35	Expenses per net KWh	0.0467	0.0141

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 1988 Plant Name: HAAS (b)	FERC Licensed Project No. 2130 Plant Name: HALSEY (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1958	1916
4	Year Last Unit was Installed	1958	1916
5	Total installed cap (Gen name plate Rating in MW)	135.00	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	144	11
7	Plant Hours Connect to Load	8,012	5,768
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	344,570,153	29,402,301
13	Cost of Plant		
14	Land and Land Rights	27,369	955,366
15	Structures and Improvements	10,563,329	2,197,723
16	Reservoirs, Dams, and Waterways	28,219,647	26,279,436
17	Equipment Costs	23,489,915	7,904,677
18	Roads, Railroads, and Bridges	735,042	247,708
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	63,035,302	37,584,910
21	Cost per KW of Installed Capacity (line 20 / 5)	466.9282	2,763.5963
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	23,345	4,637
25	Hydraulic Expenses	86,594	603
26	Electric Expenses	577,765	403,468
27	Misc Hydraulic Power Generation Expenses	622,931	133,986
28	Rents	145,660	4,127
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	120,846	24,640
31	Maintenance of Reservoirs, Dams, and Waterways	211,246	597,193
32	Maintenance of Electric Plant	728,340	235,165
33	Maintenance of Misc Hydraulic Plant	98,711	56,703
34	Total Production Expenses (total 23 thru 33)	2,615,438	1,460,522
35	Expenses per net KWh	0.0076	0.0497

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 2 (b)	FERC Licensed Project No. 1988 Plant Name: KINGS RIVER (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Underground	Semi-Outdoor
3	Year Originally Constructed	1983	1962
4	Year Last Unit was Installed	1983	1962
5	Total installed cap (Gen name plate Rating in MW)	139.50	48.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	155	52
7	Plant Hours Connect to Load	5,991	5,572
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	302,593,158	122,309,763
13	Cost of Plant		
14	Land and Land Rights	585,503	18,318
15	Structures and Improvements	38,111,605	4,985,122
16	Reservoirs, Dams, and Waterways	88,351,051	21,478,684
17	Equipment Costs	49,545,821	11,434,547
18	Roads, Railroads, and Bridges	7,535,238	417,065
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	184,129,218	38,333,736
21	Cost per KW of Installed Capacity (line 20 / 5)	1,319.9227	788.7600
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	202,111	9,467
25	Hydraulic Expenses	84,148	71,248
26	Electric Expenses	470,450	268,755
27	Misc Hydraulic Power Generation Expenses	551,482	257,708
28	Rents	21,862	52,600
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	59,146	38,084
31	Maintenance of Reservoirs, Dams, and Waterways	250,010	102,775
32	Maintenance of Electric Plant	1,353,457	266,181
33	Maintenance of Misc Hydraulic Plant	347,732	39,544
34	Total Production Expenses (total 23 thru 33)	3,340,398	1,106,362
35	Expenses per net KWh	0.0110	0.0090

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 233 Plant Name: PIT NO. 3 (b)	FERC Licensed Project No. 233 Plant Name: PIT NO. 4 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1955
4	Year Last Unit was Installed	1925	1955
5	Total installed cap (Gen name plate Rating in MW)	80.19	103.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	70	95
7	Plant Hours Connect to Load	8,742	8,683
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	6	0
12	Net Generation, Exclusive of Plant Use - Kwh	297,988,466	388,013,968
13	Cost of Plant		
14	Land and Land Rights	3,814,210	298,899
15	Structures and Improvements	6,710,905	2,343,819
16	Reservoirs, Dams, and Waterways	67,266,564	40,489,275
17	Equipment Costs	23,239,596	22,968,426
18	Roads, Railroads, and Bridges	7,421,658	3,739,401
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	108,452,933	69,839,820
21	Cost per KW of Installed Capacity (line 20 / 5)	1,352.4496	674.7809
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	43,049	50,262
25	Hydraulic Expenses	19,833	22,825
26	Electric Expenses	1,318,901	370,962
27	Misc Hydraulic Power Generation Expenses	1,415,462	1,390,306
28	Rents	4,950	4,950
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	99,526	10,282
31	Maintenance of Reservoirs, Dams, and Waterways	323,874	160,654
32	Maintenance of Electric Plant	311,415	712,596
33	Maintenance of Misc Hydraulic Plant	149,464	111,330
34	Total Production Expenses (total 23 thru 33)	3,686,474	2,834,167
35	Expenses per net KWh	0.0124	0.0073

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	FERC Licensed Project No. 2107 Plant Name: POE (b)	FERC Licensed Project No. 1962 Plant Name: ROCK CREEK (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1950
4	Year Last Unit was Installed	1958	1950
5	Total installed cap (Gen name plate Rating in MW)	142.83	125.37
6	Net Peak Demand on Plant-Megawatts (60 minutes)	120	126
7	Plant Hours Connect to Load	7,595	8,173
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	6
12	Net Generation, Exclusive of Plant Use - Kwh	431,097,156	343,268,146
13	Cost of Plant		
14	Land and Land Rights	821,115	1,777,093
15	Structures and Improvements	9,771,028	15,701,598
16	Reservoirs, Dams, and Waterways	43,586,617	44,649,060
17	Equipment Costs	36,888,453	105,607,370
18	Roads, Railroads, and Bridges	1,146,684	353,339
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	92,213,897	168,088,460
21	Cost per KW of Installed Capacity (line 20 / 5)	645.6199	1,340.7391
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	30,226	29,256
25	Hydraulic Expenses	42,873	40,750
26	Electric Expenses	446,653	1,376,204
27	Misc Hydraulic Power Generation Expenses	604,025	1,041,761
28	Rents	8,706	9,560
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	62,391	104,281
31	Maintenance of Reservoirs, Dams, and Waterways	1,487,530	585,288
32	Maintenance of Electric Plant	359,311	457,700
33	Maintenance of Misc Hydraulic Plant	32,437	63,597
34	Total Production Expenses (total 23 thru 33)	3,074,152	3,708,397
35	Expenses per net KWh	0.0071	0.0108

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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	7,737	7,792
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	6
12	Net Generation, Exclusive of Plant Use - Kwh	78,865,788	67,750,721
13	Cost of Plant		
14	Land and Land Rights	148,887	816,018
15	Structures and Improvements	837,188	4,025,705
16	Reservoirs, Dams, and Waterways	5,544,600	16,952,636
17	Equipment Costs	7,386,107	9,224,313
18	Roads, Railroads, and Bridges	131,552	215,643
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	14,048,334	31,234,315
21	Cost per KW of Installed Capacity (line 20 / 5)	1,032.9657	2,296.6408
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	13,018	5,703
25	Hydraulic Expenses	3,010	0
26	Electric Expenses	265,545	1,550,247
27	Misc Hydraulic Power Generation Expenses	253,985	150,379
28	Rents	7,305	5,076
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	32,986	23,303
31	Maintenance of Reservoirs, Dams, and Waterways	250,141	687,343
32	Maintenance of Electric Plant	469,083	157,778
33	Maintenance of Misc Hydraulic Plant	22,388	51,948
34	Total Production Expenses (total 23 thru 33)	1,317,461	2,631,777
35	Expenses per net KWh	0.0167	0.0388

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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
3,272	8,328	8,548	7
			8
125	172	65	9
125	172	53	10
0	0	0	11
181,546,867	587,025,036	259,447,247	12
			13
558,903	642,318	810,592	14
10,873,442	730,647	1,135,023	15
57,177,029	64,873,808	19,667,014	16
44,082,370	17,842,960	22,061,628	17
475,083	2,073,234	3,085,588	18
0	0	0	19
113,166,827	86,162,967	46,759,845	20
959.8543	510.8678	708.4825	21
			22
0	0	0	23
30,833	56,422	40,440	24
44,200	27,871	28,279	25
273,904	386,540	368,603	26
1,070,741	1,178,710	636,637	27
5,641	10,393	20,133	28
0	0	0	29
59,171	29,434	36,129	30
219,719	206,271	168,264	31
523,336	777,439	428,834	32
75,918	148,002	39,310	33
2,303,463	2,821,082	1,766,629	34
0.0127	0.0048	0.0068	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	03/31/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 2 (d)	FERC Licensed Project No. 1121 Plant Name: COLEMAN (e)	FERC Licensed Project No. 1962 Plant Name: CRESTA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1958	1979	1949	3
1958	1979	1950	4
117.90	12.15	73.80	5
120	13	70	6
8,390	7,895	7,697	7
			8
120	13	70	9
119	5	72	10
0	0	0	11
307,107,313	47,514,816	248,701,182	12
			13
324,156	185,376	1,365,404	14
6,092,985	1,687,763	4,511,120	15
30,301,313	23,699,300	21,089,505	16
22,311,844	13,226,312	11,385,553	17
14,485	1,238,001	135,058	18
0	0	0	19
59,044,783	40,036,752	38,486,640	20
500.8039	3,295.2059	521.4992	21
			22
0	0	0	23
30,226	706	24,161	24
42,873	16,383	29,605	25
256,495	152,529	326,412	26
746,499	64,640	680,402	27
5,416	359	5,975	28
0	0	0	29
52,504	21,311	36,069	30
201,005	331,787	127,367	31
339,184	361,924	414,726	32
37,308	65,759	35,208	33
1,711,510	1,015,398	1,679,925	34
0.0056	0.0214	0.0068	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	03/31/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2310 Plant Name: DRUM NO. 2 (d)	FERC Licensed Project No. 2310 Plant Name: DUTCH FLAT (e)	FERC Licensed Project No. 137 Plant Name: ELECTRA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1965	1943	1948	3
1965	1943	1948	4
53.10	22.00	102.50	5
50	22	98	6
6,647	7,725	8,782	7
			8
50	22	98	9
49	23	98	10
0	0	2	11
245,737,225	90,136,172	434,126,702	12
			13
273,466	808,729	753,760	14
688,204	2,094,717	1,953,936	15
8,303,044	19,421,890	26,628,895	16
7,864,666	14,237,202	23,378,266	17
433,483	407,127	895,379	18
0	0	0	19
17,562,863	36,969,665	53,610,236	20
330.7507	1,680.4393	523.0267	21
			22
0	0	0	23
18,315	8,545	165,912	24
3,466	2,727	10,375	25
833,233	379,475	921,599	26
344,463	194,200	1,094,240	27
16,301	7,605	37,585	28
0	0	0	29
35,756	25,546	169,712	30
421,832	228,488	1,153,228	31
130,760	138,637	505,245	32
62,755	47,766	105,943	33
1,866,881	1,032,989	4,163,839	34
0.0076	0.0115	0.0096	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	03/31/2017	End of 2016/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. 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
8,530	7,712	2,929	7
			8
9	9	25	9
4	9	0	10
0	0	0	11
25,538,006	32,621,444	44,863,457	12
			13
816,372	675,163	7,014	14
246,938	279,903	1,567,375	15
2,776,828	1,046,833	3,306,605	16
2,877,010	3,615,498	6,673,517	17
1,183,946	385,170	6,112	18
0	0	0	19
7,901,094	6,002,567	11,560,623	20
790.1094	600.2567	508.8302	21
			22
0	0	0	23
0	0	34,419	24
591	591	28,809	25
235,730	93,778	270,996	26
195,375	195,375	146,806	27
120	120	3,583	28
0	0	0	29
32,321	865	33,706	30
59,707	44,009	179,971	31
44,871	120,561	433,617	32
28,623	22,282	99,034	33
597,338	477,581	1,230,941	34
0.0234	0.0146	0.0274	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	03/31/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1403 Plant Name: NARROWS (d)	FERC Licensed Project No. 2310 Plant Name: NEWCASTLE (e)	FERC Licensed Project No. 2687 Plant Name: PIT NO.1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1942	1986	1922	3
1942	1986	1922	4
10.20	12.70	69.30	5
12	12	61	6
4,130	2,651	8,101	7
			8
12	12	61	9
12	0	61	10
0	0	0	11
41,831,455	16,020,946	191,845,083	12
			13
274,371	2,296,313	1,574,159	14
1,168,566	6,909,882	2,219,681	15
1,362,929	51,701,858	12,462,425	16
5,182,137	8,363,464	30,693,348	17
506,629	3,041,254	1,448,431	18
0	0	0	19
8,494,632	72,312,771	48,398,044	20
832.8071	5,693.9190	698.3845	21
			22
0	0	0	23
142,333	4,815	87,549	24
741	0	19,207	25
145,008	433,807	310,926	26
146,802	136,718	3,976,802	27
0	4,285	0	28
0	0	0	29
16,087	21,856	10,234	30
108,636	655,021	245,492	31
334,738	99,622	251,013	32
6,517	51,271	100,658	33
900,862	1,407,395	5,001,881	34
0.0215	0.0878	0.0261	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	03/31/2017	End of 2016/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 233 Plant Name: PIT NO. 5 (d)	FERC Licensed Project No. 2106 Plant Name: PIT NO. 6 (e)	FERC Licensed Project No. 2106 Plant Name: PIT NO. 7 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Outdoor	Outdoor	2
1944	1965	1965	3
1944	1965	1965	4
141.84	79.20	109.80	5
160	80	112	6
8,775	8,757	8,637	7
			8
160	80	112	9
160	80	112	10
6	0	0	11
587,630,166	312,671,995	422,763,276	12
			13
677,392	302,961	333,453	14
13,029,200	3,143,324	2,703,377	15
42,517,520	22,300,885	31,473,736	16
72,729,291	12,086,924	11,517,547	17
9,008,045	686,970	405,830	18
0	0	0	19
137,961,448	38,521,064	46,433,943	20
972.6554	486.3771	422.8957	21
			22
0	0	0	23
0	56,422	56,422	24
26,093	20,528	22,754	25
1,700,560	363,448	191,891	26
1,486,164	800,942	848,249	27
4,950	10,393	10,393	28
0	0	0	29
19,101	12,696	177,598	30
199,856	135,025	148,516	31
1,084,114	564,033	537,066	32
262,137	82,320	101,500	33
4,782,975	2,045,807	2,094,389	34
0.0081	0.0065	0.0050	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. 137 Plant Name: SALT SPRINGS (d)	FERC Licensed Project No. 2130 Plant Name: STANISLAUS (e)	FERC Licensed Project No. 137 Plant Name: TIGER CREEK (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Outdoor	Conventional	2
1931	1963	1931	3
1953	1963	1931	4
42.03	81.90	52.28	5
44	91	58	6
7,245	7,989	7,512	7
			8
44	91	58	9
34	91	58	10
2	0	6	11
174,852,172	402,164,046	269,349,942	12
			13
246,696	299,542	2,532,946	14
1,897,712	1,114,282	6,639,031	15
32,218,890	35,497,857	48,471,864	16
12,659,156	25,639,520	16,240,484	17
1,076,132	916,372	6,183,000	18
0	0	0	19
48,098,586	63,467,573	80,067,325	20
1,144.3870	774.9398	1,531.5097	21
			22
0	0	0	23
35,728	388,221	41,126	24
7,343	15,492	9,651	25
655,745	687,824	876,479	26
658,913	2,938,732	691,722	27
20,050	46,021	23,080	28
0	0	0	29
100,307	33,729	116,784	30
799,498	1,021,150	901,118	31
470,352	535,626	426,098	32
52,895	124,511	70,972	33
2,800,831	5,791,306	3,157,030	34
0.0160	0.0144	0.0117	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	03/31/2017	End of 2016/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
5,198	0	0	7
			8
20	0	0	9
12	0	0	10
0	0	0	11
34,314,798	0	0	12
			13
969,408	0	0	14
1,429,114	0	0	15
48,605,372	0	0	16
6,048,663	0	0	17
29,366	0	0	18
0	0	0	19
57,081,923	0	0	20
4,459.5252	0.0000	0.0000	21
			22
0	0	0	23
19,100	0	0	24
27,356	0	0	25
229,462	0	0	26
424,067	0	0	27
32,786	0	0	28
0	0	0	29
27,283	0	0	30
253,739	0	0	31
326,726	0	0	32
13,069	0	0	33
1,353,588	0	0	34
0.0394	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	03/31/2017	End of 2016/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

Schedule Page: 406 Line No.: 11 Column: b

Certain FERC Licensed plants have a zero Line 11 (Average Number of Employees) on pages 406 and 407 due to remote operation and headquarters. Refer to the table below for further details for each plant with a zero in Line 11. Each of these plants is attended by roving or relief operators.

PLANT NAME:	REMOTELY OPERATED (Y/N):	HEADQUARTERS:
BLACH NO. 1	Y	Balch Camp
BALCH NO. 2	Y	Balch Camp
BELDEN	Y	Caribou No. 1
JAMES B. BLACK	Y	Pit No. 5
BUCKS CREEK	Y	Rock Creek
BUTT VALLEY	Y	Caribou No. 1
CARIBOU NO. 2	Y	Caribou No. 1
COLEMAN	N	Manton
CRESTA	Y	Rock Creek
DE SABLA	N	Camp 1
DRUM NO. 2	Y	Drum No. 1
DUTCH FLAT	N	Alta Service Center
HAAS	Y	Balch Camp
HALSEY	N	Wise
HAT CREEK NO. 1	N	Burney
HAT CREEK NO. 2	N	Burney
KERCKHOFF NO. 1	N	Auberry
KERCKHOFF NO. 2	N	Auberry
KINGS RIVER	Y	Balch Camp
NARROWS	Y	Wise
NEWCASTLE	Y	Wise
PIT NO. 1	Y	Burney
PIT NO. 4	Y	Burney
PIT NO. 6	Y	Pit No. 5
PIT NO. 7	Y	Pit No. 5
POE	Y	Rock Creek
STANISLAUS	Y	Tiger Creek
WEST POINT	Y	Tiger Creek
A. G. WISHON	N	Auberry

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: (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	3,369
7	Net Plant Capability (in megawatts)	1,212
8	Average Number of Employees	8
9	Generation, Exclusive of Plant Use - Kwh	860,672
10	Energy Used for Pumping	1,359,241
11	Net Output for Load (line 9 - line 10) - Kwh	-498,569
12	Cost of Plant	
13	Land and Land Rights	706,800
14	Structures and Improvements	180,562,654
15	Reservoirs, Dams, and Waterways	440,248,201
16	Water Wheels, Turbines, and Generators	244,938,593
17	Accessory Electric Equipment	57,334,718
18	Miscellaneous Powerplant Equipment	23,840,907
19	Roads, Railroads, and Bridges	8,773,225
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	956,405,098
22	Cost per KW of installed cap (line 21 / 4)	908.2669
23	Production Expenses	
24	Operation Supervision and Engineering	146,862
25	Water for Power	287,653
26	Pumped Storage Expenses	55,515
27	Electric Expenses	3,362,495
28	Misc Pumped Storage Power generation Expenses	4,430,460
29	Rents	43,107
30	Maintenance Supervision and Engineering	795,636
31	Maintenance of Structures	1,011,796
32	Maintenance of Reservoirs, Dams, and Waterways	1,446,953
33	Maintenance of Electric Plant	2,466,961
34	Maintenance of Misc Pumped Storage Plant	1,553,735
35	Production Exp Before Pumping Exp (24 thru 34)	15,601,173
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	15,601,173
38	Expenses per KWh (line 37 / 9)	18.1267

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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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	3,121	13,880,873
3	Centerville FERC No.803	1904	6.40	6.4		17,473,694
4	Chili Bar FERC No.2155	1965	7.02	7.0	32,314	16,798,334
5	Coal Canyon	1907				2,993,963
6	Cow Creek FERC No.606	1907	1.44	1.8	6,803	3,176,611
7	Crane Valley FERC No.1354	1919	0.99	0.9	1,759	19,828,426
8	Deer Creek FERC No.2310	1908	5.50	5.7	15,855	80,547,957
9	Hamilton Branch	1921	5.39	4.8	10,097	8,410,998
10	Inskip FERC No.1121	1979	7.65	8.0	18,803	19,890,064
11	Kern Canyon FERC No. 178	1921	9.54	11.5	33,870	12,687,164
12	Kilarc FERC No.606	1904	3.00	3.2	15,459	4,297,615
13	Lime Saddle	1906	2.00	2.0	3,269	15,440,561
14	Merced Falls FERC No.2467	1930	3.44	3.5	7,949	5,497,360
15	Oak Flat FERC No.2105	1985	1.40	1.3	5,838	8,296,206
16	Phoenix FERC No.1061	1940	1.60	2.0	7,874	13,704,016
17	Potter Valley FERC No.77	1910	9.46	9.2	8,326	46,267,853
18	San Joaquin No. 1-A FERC No.1354	1919	0.42	0.4	520	34,754,988
19	San Joaquin No. 2 FERC No.1354	1917	2.88	3.2	3,389	29,953,990
20	San Joaquin No. 3 FERC No.1354	1923	4.00	4.2	480	31,662,383
21	South FERC No.1121	1979	6.75	7.0	20,390	16,744,748
22	Spaulding No. 1 FERC No.2310	1928	7.04	7.0	16,646	36,774,597
23	Spaulding No. 2 FERC No.2310	1928	3.70	4.4	896	17,023,303
24	Spaulding No. 3 FERC No.2310	1929	6.61	5.8	17,351	16,491,935
25	Spring Gap FERC No.2130	1921	6.00	7.0	34,813	10,229,971
26	Toadtown FERC No.803	1986	1.80	1.5	3,202	6,389,560
27	Tule FERC No.1333	1914	4.50	6.4	12,942	10,288,472
28	Volta No.1 FERC No.1121	1980	8.55	9.0	43,593	17,539,395
29	Volta No.2 FERC No.1121	1981	0.95	0.9	4,783	2,774,343
30	Wise II FERC No.2310	1986	2.87	3.2	-30	14,192,125
31	Miscellaneous Minor					4,224,659
32						
33	Photo Voltaic Generating Plants:					
34	AT&T PARK SOLAR ARRAYS	2007	0.11	0.1	138	1,990,928
35	SF SERVICE CENTER SOLAR ARRAY 1 & 2	2007	0.18	0.2	193	72,959
36	Vaca Dixon Solar Station	2009	2.00	2.0	4,028	10,881,965
37	Five Points - Schindler Solar Station #1	2011	15.00	15.0	29,839	54,573,062
38	Westside - Schindler Solar Station #2	2011	15.00	15.0	30,612	48,086,420
39	Stroud Solar Station	2011	20.00	20.0	38,539	61,716,847
40	Cantua Solar Station	2012	20.00	20.0	43,802	56,287,380
41	Giffen Solar Station	2012	10.00	10.0	20,678	31,336,409
42	Huron Solar Station	2012	20.00	20.0	42,504	61,061,792
43	Gates Solar Station	2013	20.00	20.0	43,717	65,587,410
44	West Gates Solar Station	2013	10.00	10.0	22,441	35,740,846
45	Guernsey Solar Station	2013	20.00	20.0	45,922	77,054,759
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	03/31/2017	End of 2016/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	1,508	8,504,503
3	California State University East Bay	2011	1.40	1.4	3,666	6,582,640
4						
5	INTERNAL COMBUSTION:					
6	(EMERGENCY STANDBY UNITS)					
7	Downieville Diesel Plant	1966	0.75			95,289
8	Grass Valley Mobile Diesel Generator	1971	0.25			38,497
9	Sierra City Mobile Diesel Generator	1972	0.33			49,054
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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
13,880,873	160,308		207,910	Water		2
2,730,265	427,409		348,034	Water		3
2,392,925	395,899		224,938	Water		4
	107,682		228,468	Water		5
2,205,980	86,267		304,597	Water		6
20,028,713	280,862		541,699	Water		7
14,645,083	280,737		791,225	Water		8
1,560,482	299,878		349,882	Water		9
2,600,008	303,643		867,791	Water		10
1,329,891	543,907		350,890	Water		11
1,432,538	126,610		574,801	Water		12
7,720,280	363,375		1,091,028	Water		13
1,598,070	216,012		163,708	Water		14
5,925,861	196,988		124,561	Water		15
8,565,010	476,176		644,107	Water		16
4,890,894	2,478,283		781,641	Water		17
82,749,971	247,366		304,200	Water		18
10,400,691	314,243		423,873	Water		19
7,915,596	408,090		546,946	Water		20
2,480,703	234,643		1,039,658	Water		21
5,223,664	320,957		297,524	Water		22
4,600,893	298,664		98,274	Water		23
2,494,998	227,212		203,983	Water		24
1,704,995	496,778		345,305	Water		25
3,549,756	312,639		196,352	Water		26
2,286,327	477,541		375,415	Water		27
2,051,391	658,199		792,038	Water		28
2,920,361	313,948		187,779	Water		29
4,944,991	429,459		689,775	Water		30
				Water		31
						32
						33
17,936,288			17,262	Solar		34
796,434			17,695	Solar		35
5,440,983	23,923		81,868	Solar		36
3,638,204	65,385		183,710	Solar		37
3,205,761	111,983		119,766	Solar		38
3,085,842	133,341		178,863	Solar		39
2,814,369	71,453		138,033	Solar		40
3,133,641	49,908		145,135	Solar		41
3,053,090	59,179		115,762	Solar		42
3,279,371	32,729		100,178	Solar		43
3,574,085	22,255		82,294	Solar		44
3,852,738	93,530		260,193	Solar		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	03/31/2017	End of 2016/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
5,500,677	209,803		315,832	Natural Gas		2
4,701,886	189,644		272,436	Natural Gas		3
						4
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				Diesel		7
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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.: 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	03/31/2017	End of 2016/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	A.E.C. Windfarm	Pittsburg-Tesla	230.00		T			2
2	(Ralph Tap)	#2						
3	American Canyon	American Canyon-						
4		Sobrante	230.00		T			2
5	American-Canyon	American	230.00		T			2
6	Sobrante	Carquinez						
7		Straits						
8	American-Canyon	Sobrante	230.00		T			2
9	Sobrante	Sub						
10	Arco	Midway	230.00		T			1
11	Balch PP	McCall	230.00		T			1
12	Haas PP	McCall	230.00		T			1
13			230.00		T			1
14	Belden PP	Rock Crk. Jct.	230.00		T			1
15		#1						
16	Belden PP	Butte County						
17		Table Mtn.	230.00		T			1
18	Bellota	Gregg #1	230.00		T			1
19			230.00		T			1
20			230.00		T			1
21			230.00		T			1
22		#2	230.00		T			1
23			230.00		T			1
24			230.00		T			1
25	Bellota	Tesla #1	230.00		T			1
26		#2	230.00		T			1
27			230.00		SSP			1
28			230.00		T			1
29	Black PP	Pit #5 PP	230.00		T			1
30	Bottle Rock PP		230.00		T			1
31	Bucks Crk PP		230.00		T			1
32	Caribou PH #2	Table Mtn.	230.00		T			1
33			230.00		T			1
34			230.00		T			1
35	Castle Rock Jct.	Fulton #1	230.00		SSP			1
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Castle Rock	Fulton #2	230.00		T			
2	Junction							
3			230.00		SSP			1
4	Castle Rock	Lakeville Sub #1	230.00		T			2
5			230.00		T			1
6			230.00		UG			1
7	Castle Rock	Lakeville Sub #2	230.00		T			1
8			230.00		T			1
9								
10	Center of	American Canyon-	230.00		T			2
11	Carquinez Straits	Sobrante						
12								
13	Contra Costa	Contra Costa						
14	PP	Sub #1 & 2	230.00		T			1
15	Contra Costa	Newark #1						
16	PP	and #2	230.00		T			2
17			230.00		T			2
18			230.00		T			2
19	Contra Costa	Newark #3						
20	PP	Research Sub	230.00		SSP			1
21	Contra Costa	Tesla #1	230.00		T			1
22	PP		230.00		T			1
23	Contra Costa	Tesla #2	230.00		T			1
24	Contra Costa							
25	PP		230.00					1
26	Contra Costa	Tesla #2						
27	PP	Windmaster						
28		Sub	230.00		T			1
29	Contra Costa	Brentwood Sub	230.00		T			1
30	PP	Tesla #1 & 2	230.00		T			1
31	Contra Costa	San Mateo	230.00		T			2
32	PP	#1 & #2	230.00		T			2
33			230.00		T			2
34			230.00		T			2
35			230.00		T			2
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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	Contra Costa	San Mateo	230.00		T			2
2	PP	#1 & #2	230.00		T			2
3	Cottonwood	Vaca-Dixon #1	230.00		T			1
4		#2	230.00		T			1
5	Cottonwood	Vac-Dixon #2	230.00		T			1
6	Diablo Cyn PP	Gates	500.00		T			1
7	Diablo Cyn PP	Mesa	230.00		T			1
8	Diablo Cyn PP	Midway	500.00		T			1
9	Diablo Cyn PP	Midway #3	500.00		T			1
10	Diablo Cyn PP #1	D.C. Smith Yard	500.00		T			1
11	Diablo Cyn PP #2	D.C. Switch Yard	500.00		T			1
12	Fulton	Ignacio #1	230.00		T			1
13			230.00		SSP			1
14	Fulton	Ignacio #2	230.00		T			1
15			230.00		SSP			1
16	Gates	Gregg	230.00		T			1
17	Gates	Arco	230.00		T			1
18	Gates	McCall	230.00		T			1
19	Gates	Panoche #1	230.00		T			1
20			230.00		SWP			1
21		#2	230.00		T			1
22	Geysers ll	Castle Rock	230.00		T			2
23	Castle Rock	Jct.- Fulton						
24	Jct. Cir.	Cir. #2						
25	Geysers 20	Geysers 13	230.00		T			1
26		Tap						
27	Geysers 16	NCPA Tap	230.00		T			1
28	Geysers 12 PP	Geysers 14	230.00		T			1
29		Castle Rock						
30	Geysers PP	Castle Rock	230.00		T			2
31	(Unit #14)	Lakeville						
32	Geysers PP	Castle Rock	230.00		T			1
33	(Unit #5 & 6)	Jct.						
34	Geysers PP	Castle Rock	230.00		T			1
35	(Unit ll)	Jct.						
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	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	Geysers PP	Castle Rock	230.00		T			1
2	(Unit 9 & 10)	Jct.						
3	Geysers PP	Geysers PP						
4	(Unit 13)	(Unit (9)						
5		Castle Rock						
6		Jct.	230.00		T			1
7			230.00		UG			1
8	Geysers PP	Occidental						
9	(Unit (9)	Petroleum						
10	Geysers PP	Geothermal						
11	(Unit 13)	PP #1	230.00		T			1
12	Geysers PP	Castle Rock	230.00		T			1
13	(Unit 14)	Jct.	230.00		T			1
14	Geysers PP	Geysers PP						
15	(Unit 17)	(Unit 11)						
16		Castle Rock						
17		Jct.	230.00		T			1
18	Geysers PP	Geysers PP						
19	(Unit 18)	(Unit 14)						
20		Castle Rock						
21		Jct.	230.00		T			1
22	Gregg	Ashlan Av.	230.00		T			1
23		Sub.	230.00		T			1
24	Gregg-Ashlan	Figarden Sub #1						
25	Av. Sub		230.00		UG			1
26	Gregg	Herndon #1	230.00		T			1
27		& #2	230.00					1
28	Helms	Gregg #1	230.00		T			1
29			230.00		T			1
30		#2	230.00		T			1
31			230.00					1
32	Herndon-Ashlan	Figarden Sub #2						
33	Av.		230.00		UG			1
34	Herndon	Ashland Av.	230.00		T			1
35	Herndon	Kearney	230.00		T			1
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Ignacio	American	230.00		T			1
2	Jct.	Canyon Jct.						
3	Ignacio	Ignacio	230.00		T			2
4	Jct.	Sub						
5	Ignacio	Ignacio	230.00		T			2
6	Loop Cir.	Loop Cir.						
7	1 & 2	1 & 2						
8	Indian Springs	Round Mt. Sub.	500.00		T			1
9	Lakeville Sub	Ignacio Jct.	230.00		T			2
10	Lakeville	Ignacio #2	230.00		UG			2
11	Los Banos Sub	Midway Sub						
12		#1	500.00		T			1
13		#2	500.00		T			1
14	Los Banos Sub	Panoche	230.00		T			1
15	Los Banos Sub	San Luis						
16		Pumps #1	230.00		T			1
17		#2	230.00		T			1
18	Martin	Embarcadero						
19		#1 (HZ)	230.00		UG			1
20	Martin	Embarcadero						
21		#2 (HZ)	230.00		UG			1
22	Melones	Warnerville						
23		Jct. #1 & 2	230.00		T			2
24	Metcalf	Monta Vista	230.00		T			2
25	Metcalf	Monta Vista	230.00		SSP			1
26	Metcalf	Monta Vista	230.00		T			1
27	Metcalf	Moss Landg#1&#2	230.00		T			2
28	Metcalf	Newark #1&#2	230.00		T			2
29			230.00		T			2
30	Midddle Fork PP	Gold Hill	230.00		T			1
31			230.00		H			1
32			230.00		T			1
33	Middle Fork PP	Gold Hill	230.00		WH			1
34	Middle Fork-	Orangevale						
35	Gold Hill	Sub (SMUD)	230.00		T			1
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Middle Fork -	Pocket Sub						
2	Gold Hill	(SMUD)	230.00		T			1
3			230.00					1
4								
5	Midway	Kern PP #1	230.00		T			1
6	Midway	Kern PP #2	230.00		T			1
7	Midway	Kern PP #3	230.00		T			1
8	Midway	Kern PP #4	230.00		T			1
9	Midway	Whirlwind	500.00		T			1
10	Midway	Wheeler Ridge						
11		#1	230.00		T			1
12		#2	230.00		T			1
13	Midway-Kern #1	Stockdale Sub						
14		#1	230.00		T			1
15			230.00		T			1
16			230.00		SSP			1
17	Midway -Kern #3	Stockdale Sub						
18		#2	230.00		T			1
19	Midway-Wheeler	Buena Vista						
20	Ridge #1 & 2	Pump Plant						
21		(State DWR)	230.00		T			2
22	Midway-Wheeler	Wheeler Ridge						
23	Ridge #1 & 2	Pump Plant						
24		(State DWR)	230.00		T			2
25	Midway-Wheeler	Wind Gap Pump						
26	Ridge #1 & 2	(State DWR)	230.00		T			2
27	Monta Vista	Jefferson	230.00		T			2
28	Moraga	Newark	230.00		T			
29			230.00		T			
30			230.00		T			
31			230.00		T			
32			230.00		T			
33			230.00		T			
34			230.00		T			
35	Morro Bay PP	Gates	230.00		T			2
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/Q4

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1	Morro Bay PP	Midway	230.00		T			2
2	Morro Bay PP	Mesa	230.00		T			1
3	Morro Bay PP-MESA	Diablo Cyn PP	230.00		T			2
4	Moss Landing PH	Los Banos Sub	230.00		T			1
5	Moss Landing PH	Panoche #1	230.00		T			1
6			230.00		T			2
7	Moss Landing PH	Panoche #2	230.00		T			1
8	Moss Landing	Moss Landing						
9	230KV SW.	115KV SW.	230.00		T			
10	Moss Landing	Los Banos	500.00		T			1
11	Moss Landing	Metcalf	500.00		T			1
12	Newark	San Mateo	230.00		T			2
13			230.00					1
14	NCPA 1&2 Tap Line	CR Collector Line	230.00		T			2
15	Panoche	Kearney	230.00		T			1
16	Panoche-Kearney	McMullin Sub	230.00		T			1
17	Panoche	McCall	230.00		T			1
18	Panoche	McCall	230.00		T			1
19	Pittsburg PP	Moraga #1 & 2	230.00		T			2
20			230.00					2
21	Pittsburg PP	Moraga #3	230.00		T			1
22			230.00		T			1
23			230.00		T			1
24	Pittsburg-Panoche	Los Banos	230.00		T			1
25	Pittsburg PP	Sobrante Sub	230.00		T			2
26	Pittsburg PP	Tesla Sub	230.00		T			2
27	Pittsburg PP	Newark	230.00		T			1
28			230.00		T			1
29			230.00		T			1
30			230.00		T			1
31			230.00		T			1
32			230.00		T			1
33								
34	Pit # 1-	Sierra Pacific						
35	Cottonwood	Industry	230.00		T			1
36					TOTAL	13,746.93	4,391.37	381

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1	Pit # 1 PP	Vaca-Dixon	230.00		T			1
2			230.00		T			1
3								
4	Pit # 1 PP	Vaca-Dixon	230.00		T			1
5			230.00		WH			1
6	Pit # 1 PP	Vaca-Dixon	230.00		T			1
7			230.00		T			1
8			230.00		T			1
9								
10			230.00		T			1
11			230.00		T			1
12			230.00		T			1
13			230.00		T			1
14			230.00		SH			1
15			230.00		T			1
16			230.00		T			1
17	Pit # 4 PP	Round Mtn.	230.00		T			1
18			230.00		WH			1
19			230.00		T			1
20			230.00		WH			1
21			230.00		T			1
22			230.00		WH			1
23	Pit # 5 PP	Mega Renewable-						
24		able Sub	230.00		WH			1
25	Pit # 5 PP	Round Mtn.	230.00		T			1
26			230.00		T			1
27			230.00		WH			1
28			230.00		T			1
29			230.00		T			1
30			230.00		WH			1
31			230.00		WH			1
32	Pit # 5 PP	Round Mtn.	230.00		WH			1
33			230.00		T			1
34	Pit # 5 PP	Roaring Crk.						
35	Round Mtn.	Sub	230.00		WH			1
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1	Pit # 6 PP	Pit # 6 Jct.	230.00		T			1
2			230.00		WH			1
3	Pit # 7 PP	Pit # 7 Jct.	230.00		T			1
4	Pit # 7 PP	Pit # 7 Jct.	230.00		WH			1
5	Pittsburg-	Rossmoor Sub						
6	Moraga #1		230.00		T			1
7	Pittsburg-	Roosmoor Sub						
8	Moraga #2		230.00		T			1
9	Pit-Vaca Dixon	Sierra Pacific						
10		Industry	230.00		T			1
11								
12	Rancho Seco	Bellota Sub						
13	PP (SMUD)		230.00		T			2
14	Rancho Seco	Stagg Sub	230.00		T			1
15	PP (SMUD)	and	230.00		T			1
16		Tesla Sub	230.00		T			2
17	Rio Oso	Bellota #1	230.00		T			2
18		and #2	230.00		T			2
19			230.00		T			1
20			230.00		T			1
21			230.00		T			1
22	Rio Oso Sub	T. 10/44	230.00		T			1
23		(SMUD)	230.00		T			1
24	Rio Oso Sub	Tesla Sub	230.00		T			1
25	Rio Oso-Tesla	Eight Mile	230.00		LST			1
26	T.77/323A	Substation						
27	Rock Creek PP	Riso Oso #1	230.00		T			1
28	Rock Creek PP	Riso Oso #2	230.00		T			1
29	Round Mountain	Cottonwood	230.00		T			1
30			230.00		WH			1
31	Round Mountain	Table Mtn. #1	500.00		T			1
32			500.00		T			1
33	Round Mountain	Table Mtn. #2	500.00		T			1
34			500.00		T			1
35	San Mateo Sub	Martin Sub	230.00		UG			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	Stockdale	Bakersfield						
2		#1	230.00		T			1
3	Stockdale	Bakersfield						
4		#1	230.00		SSP			1
5		#2	230.00		T			1
6			230.00		SSP			1
7	Table Mtn.	Rio Oso #1	230.00		T			1
8	Table Mtn.	Rio Oso #2	230.00		T			1
9	Table Mtn.	Tesla Sub	500.00		T			1
10	Tesla Sub		500.00		T			1
11	Table Mtn.	Vaca-Dixon	500.00		T			1
12	Tesla Sub	Lawrence Lab	230.00		T			1
13			230.00		SSP			1
14	Tesla Sub	Los Banos Sub						
15		#1	500.00		T			1
16		Los Banos Sub						
17		#2	500.00		T			1
18	Tesla Sub	Metcalf Sub	500.00		T			1
19	Tesla	Midway #1	230.00		T			1
20			230.00		T			1
21	Tesla	Midway #2	230.00		T			1
22			230.00		T			1
23			230.00		T			2
24	Tesla	Parker (MID)	230.00		T			1
25			230.00		T			2
26			230.00		T			1
27			230.00		T			1
28	Tesla	USBR Tracy						
29		#1 & 2	230.00		T			2
30	Tesla	Newark #1	230.00		T			1
31	Tesla	Newark #2	230.00		T			1
32	Tiger Creek	Bellota #1	230.00		T			1
33			230.00		T			1
34			230.00		T			1
35			230.00		T			1
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Tiger Creek	Bellota #2	230.00		T			1
2			230.00		T			1
3	Tiger Creek	Bellota #2	230.00		T			2
4			230.00		T			1
5	Tiger Creek	Bellota #2	230.00		T			1
6	U.S. Windpower	Contra Costa-						
7	Sub	Tesla #1	230.00		T			1
8	Vac Dixon	Vac Dixon						
9	Moraga Cir.#1	Moraga Cir. #1	230.00		T			2
10	Vac Dixon	Moraga Sub						
11	Moraga Cir.#2	Bus Structure	230.00		T			2
12	Vac Dixon	Contra Costa						
13		Sub #1	230.00		T			1
14			230.00		T			1
15			230.00		T			1
16			230.00		T			1
17			230.00		T			1
18	Vac Dixon	Contra Costa						
19		Power #2	230.00		T			1
20			230.00		T			1
21			230.00		T			1
22			230.00		T			1
23								
24	Vac Dixon-	Peabody Sub						
25	Contra Costa							
26	#1 and 2		230.00		T			2
27	Vac Dixon	Lakeville	230.00		T			2
28			230.00		T			2
29	Vac Dixon	Moraga #1	230.00		T			2
30			230.00		T			1
31			230.00		T			1
32			230.00		T			1
33	Vac Dixon	Moraga #1	230.00		T			1
34								
35								
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Vac Dixon	Moraga #2	230.00		T			2
2			230.00		T			1
3			230.00		T			1
4			230.00		T			1
5	Vac Dixon	Telsa	500.00		T			1
6			500.00		T			1
7	Walnut (TID)	Los Banos	230.00		T			2
8			230.00		T			2
9			230.00		T			1
10			230.00		T			1
11	Newark	Los Esteros	230.00		P			2
12	Los Esteros	Metcalf	230.00		P			
13	Newark	Los Esteros	230.00		UG Duct Bank			1
14	Los Esteros	Metcalf	230.00		UG Duct Bank			1
15	Cayetano	Vineyard	230.00		UG Duct Bank			2
16	Vineyard	Newark	230.00		UG Duct Bank			2
17	Contra Costa	Cayetano	230.00		UG Duct Bank			2
18	Cayetano	Vineyard	230.00		UG Duct Bank			2
19	North Dublin Substation	North Dublin Transition Sta	230.00		T			2
20	Jefferson	Martin	230.00		P			2
21	Birds Landing Switching Sub	High Winds Sub	230.00		P			1
22	North Dublin Substation	Cayetano	230.00		UG Duct Bank			1
23	North Dublin Substation	Vineyard	230.00		UG Duct Bank			1
24	Shiloh II	Birds Landing Sw Sta	230.00		P			1
25	Panoche Energy Center	Panoche Sub	230.00		P			1
26	Embarcadero GIS Termination	North Transition Manhole	230.00		UG			1
27	N TransitionManhole SpearSt	South Transition Manhole	230.00		UG			1
28	S Transition Manhole 23rdSt	Potrero GIS Termination	230.00		UG			1
29								
30	Sum Lines above Towers		500.00			1,325.89		
31			230.00			3,050.28	1,913.98	
32			115.00			2,024.75	1,544.35	
33			70.00			153.68	51.27	
34			60.00			207.67	253.68	
35	Sum Lines above Poles							
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1			500.00			1.78		
2			230.00			251.64	33.03	
3			115.00			2,197.40	298.07	
4			70.00			1,285.89	42.63	
5			60.00			3,156.19	254.36	
6								
7	Other Undground		230.00			3.33		
8	Transmission Lines		115.00			83.96		
9			70.00					
10			60.00			4.47		
11								
12	Transmission Roads							
13	and Trails							
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	13,746.93	4,391.37	381

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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.
1113AAC								1
								2
								3
2300AL								4
2156SSAC								5
								6
								7
AL2300								8
								9
795ACSR								10
954AL								11
795ACSR								12
954AL								13
795ACSR								14
								15
								16
795ACSR								17
500CU								18
650CU								19
795ACSR								20
1113AL								21
500CU								22
795ACSR								23
1113AL								24
954SSAC								25
954SSAC								26
954SSAC								27
954SSAC								28
795ACSR								29
1113AL								30
795ACSR								31
795ACSR								32
1113AL								33
954AL								34
1113AL								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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	03/31/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1113AL								1
								2
								3
2300AL								4
1113AL								5
3500AL								6
2300AL								7
1113AL								8
								9
2156SSAC								10
								11
								12
								13
795ACSR								14
								15
954ACSR								16
795ACSR								17
1113AL								18
								19
1113AL								20
954ACSR								21
1113AL								22
1113AL								23
								24
954ACSR								25
								26
								27
1113AL								28
1113AL								29
1113AL								30
954ACSR								31
2300AL								32
954ACSR								33
1113AL								34
954ACSR								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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	03/31/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954ACSR								1
954ACSR								2
954ACSR								3
954ACSR								4
1113AL								5
2300AL								6
1113AL								7
2300AL								8
2300AL								9
2300AL								10
2300AL								11
1113AL								12
1113AL								13
1113AL								14
1113AL								15
1113AL								16
795ACSR								17
1113AL								18
795ACSR								19
795ACSR								20
795ACSR								21
1113AL								22
								23
								24
1431AL								25
								26
1113AL								27
1113AL								28
								29
1113AL								30
								31
1113AL								32
								33
1113AL								34
								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1113AL								1
								2
								3
								4
								5
1431AL								6
3500AL								7
								8
								9
								10
1113AL								11
1113AL								12
1113AL								13
								14
								15
								16
1113AL								17
								18
								19
								20
1113AL								21
794ACSR								22
1113AL								23
								24
1250 OFPA								25
Pipe type								26
								27
1113AL								28
1113AL								29
1271ACSR								30
								31
								32
1250 OFPA								33
Pipe type								34
795ACSR								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1113AL								1
								2
1113AL								3
								4
1113AL								5
								6
								7
1113AL								8
1852ACSR								9
3500AL								10
2300AL								11
1113AL								12
1113AL								13
1113AL								14
								15
2500HPCU								16
								17
								18
2500CU								19
								20
2500CU								21
								22
1113AL								23
1113AL								24
1113AL								25
2300AL								26
795ACSR								27
795ACSR								28
1113AL								29
795ACSR								30
795ACSR								31
1113AL								32
1113AL								33
								34
1113AL								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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	03/31/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
1113AL								2
1113AL								3
								4
795ACSR								5
795ACSR								6
1113AL								7
1113AL								8
2300AL								9
								10
1113AL								11
1113AL								12
								13
795ACSR								14
1113AL								15
1113AL								16
								17
1113AL								18
								19
								20
1113AL								21
								22
								23
1113AL								24
								25
1113AL								26
1113AL								27
954ACSR								28
954ACSR								29
1113AL								30
954ACSR								31
795ACSR								32
1113AL								33
1113AL								34
1113AL								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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	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)	
1113ACSS								1
1113AL								2
1113AL								3
2300AL								4
795ACSR								5
2300AL								6
795ACSR								7
								8
2300AL								9
2300AL								10
2300AL								11
1113AL								12
1113AL								13
1113AL								14
1113AL								15
1113ACSS								16
795ACSR								17
1113AL								18
954ACSR								19
954AL								20
954AL								21
954ACSR								22
1113AL								23
1113AL								24
954AL								25
2300AL								26
954AL								27
1113AL								28
1113AL								29
954AL								30
795ACSR								31
1113AL								32
								33
								34
7954CSR								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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	03/31/2017	End of 2016/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.
1113AL								1
954ACSR								2
								3
954AL								4
795ACSR								5
795ACSR								6
643.7CU								7
518ACSR								8
								9
954ACSR								10
954AL								11
795ACSR								12
643.7CU								13
518ACSR								14
518ACSR								15
500CU								16
795ACSR								17
795ACSR								18
380.5CU								19
380.5CU								20
518ACSR								21
1113AL								22
								23
518ACSR								24
795ACSR								25
795ACSR								26
380.5CU								27
380.5CU								28
380.5CU								29
380.5CU								30
1113AL								31
1113AL								32
1113AL								33
								34
1113AL								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	36

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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)	
1113AL								1
1113AL								2
795ACSR								3
795ACSR								4
								5
795ACSR								6
								7
1113AL								8
								9
715.5ACSR								10
								11
								12
2300AL								13
954AL								14
1113AL								15
1113AL								16
795ACSR								17
1113AL								18
1113AL								19
1113AL								20
795ACSR								21
1113AL								22
1113AL								23
1113AL								24
1113								25
								26
795ACSR								27
795ACSR								28
795ACSR								29
795ACSR								30
1825ACSR								31
2300AL								32
1825ACSR								33
2300AL								34
2500HPCU								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	36

TRANSMISSION LINE STATISTICS (Continued)

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								1
1113AL								2
								3
1113AL								4
1113AL								5
1113AL								6
1113AL								7
1113AL								8
2300AL								9
1852ACSR								10
								11
2300AL								12
1113AL								13
								14
2300AL								15
								16
2300AL								17
2300AL								18
1113AL								19
795ACSR								20
1113AL								21
795ACSR								22
795ACSR								23
795ACSR								24
795ACSR								25
954AL								26
954AL								27
								28
954ACSR								29
2300AL								30
2300AL								31
518ACSR								32
795ACSR								33
500CU								34
643.7CU								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	36

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TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
518ACSR								1
518ACSR								2
1113AL								3
500CU								4
643.7CU								5
								6
1113AC								7
								8
1113AL								9
								10
1113AL								11
								12
500CU								13
643.7CU								14
795ACSR								15
954ACSR								16
1113SSAC								17
								18
643.7CU								19
795ACSR								20
954ACSR								21
1113SSAC								22
								23
								24
								25
1113AL								26
1113AL								27
954ACSR								28
1113AL								29
1113AL								30
954ACSR								31
954AL								32
Other								33
								34
								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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	03/31/2017	End of 2016/Q4

TRANSMISSION LINE STATISTICS (Continued)

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1113AL								1
954ACSR								2
954AL								3
Other								4
1855ACSR								5
2300AL								6
795ACSR								7
1113AL								8
954AL								9
954AL								10
2-2300 AL								11
2-2300 AL								12
2-2500 kcmil CU X								13
2-2500 kcmil CU X								14
2000 kcmil CU XLP								15
2000 kcmil CU XLP								16
1000 sq.mm CU								17
1000 sq.mm CU XL								18
954ACSR								19
954ACSR								20
1113AL								21
2000 kcmil CU XLP								22
2000 kcmil CU XLP								23
1431 AAC								24
2-1113 AAC								25
2500XLPE								26
1400XLPE								27
2500XLPE								28
								29
	24,381,459	399,602,220	424,276,857	913,182	6,644,078		7,557,260	30
	64,993,155	1,522,537,727	1,587,530,882	2,779,830	20,225,334		23,005,164	31
	31,205,023	399,271,411	430,476,434	2,122,051	15,439,503		17,561,554	32
	1,669,393	19,324,667	20,994,060	105,449	767,218		872,667	33
	4,570,395	37,833,972	42,404,367	128,807	937,165		1,065,972	34
								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	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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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
	46,059,950	426,086,568	472,146,518	1,749,586	12,729,542		14,479,128	3
	10,704,631	161,050,674	171,755,305	1,015,883	7,391,305		8,407,188	4
	24,341,564	399,730,491	424,072,055	2,603,391	18,941,611		21,545,002	5
								6
	2,790,742	238,509,403	241,300,145	83,680	34,828		118,508	7
	101,945	447,670,146	448,100,535	2,360,123	982,282		3,342,405	8
								9
		18,344,348	18,344,348	120,117	49,993		170,110	10
								11
		72,109,581	72,109,581					12
								13
								14
								15
								16
								17
								18
								19
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								21
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								27
								28
								29
								30
								31
								32
								33
								34
								35
	210,818,257	4,142,071,208	4,353,511,087	13,982,099	84,142,859		98,124,958	36

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: f

The data for this column 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. This detailed data is expected to be available after the report is filed.

Schedule Page: 422 Line No.: 1 Column: g

The data for this column 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. This detailed data is expected to be available after the report is filed.

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

Bundled

Schedule Page: 422 Line No.: 8 Column: i

Bundled

Schedule Page: 422 Line No.: 30 Column: i

Bundled

Schedule Page: 422.1 Line No.: 4 Column: i

Bundled

Schedule Page: 422.1 Line No.: 5 Column: i

Bundled

Schedule Page: 422.1 Line No.: 6 Column: i

Bundled

Schedule Page: 422.1 Line No.: 7 Column: i

Bundled

Schedule Page: 422.1 Line No.: 8 Column: i

Bundled

Schedule Page: 422.3 Line No.: 28 Column: i

Bundled

Schedule Page: 422.3 Line No.: 29 Column: i

Bundled

Schedule Page: 422.3 Line No.: 30 Column: i

Bundled

Schedule Page: 422.3 Line No.: 33 Column: i

Oil Filled

Schedule Page: 422.3 Line No.: 34 Column: i

AL cable

Schedule Page: 422.4 Line No.: 5 Column: f

Idle.

Schedule Page: 422.4 Line No.: 17 Column: i

Bundled

Schedule Page: 422.4 Line No.: 35 Column: f

For 6.53 miles, the #2 position on these towers is occupied by the Sacramento Municipal Utilities District's (SMUD)White Rock-Elverta 230 kV line. SMUD purchased a half interest in these towers.

Schedule Page: 422.5 Line No.: 2 Column: g

Property of Sacramento Municipal Utility District. Excluded from total length on last page of 422.

Schedule Page: 422.5 Line No.: 35 Column: i

Bundled

Schedule Page: 422.6 Line No.: 32 Column: i

Bundled

Schedule Page: 422.8 Line No.: 14 Column: g

Property of Sacramento Municipal Utility District. Excluded from total length on last page of 422.

Schedule Page: 422.8 Line No.: 24 Column: g

Rio Oso-Tesla 230kV Line: For 15.84 miles, the #2 position of these towers is occupied by the Sacramento Municipal Utility District's White Rock-Pocket 230kV line; district purchased half interest in these towers.

Schedule Page: 422.8 Line No.: 35 Column: i

Gas filled

Schedule Page: 422.9 Line No.: 2 Column: i

Pipe type cable

Schedule Page: 422.9 Line No.: 26 Column: g

Poles jointly owned by Modesto Irrigation District (MID) and Turlock Irrigation District (TID). Conductor is property of MID. Excluded from total length on last page of 422.

Schedule Page: 422.9 Line No.: 27 Column: g

Property of MID. Excluded from total length on last page of 422.

Schedule Page: 422.9 Line No.: 30 Column: i

Bundled

Schedule Page: 422.9 Line No.: 31 Column: i

Bundled

Schedule Page: 422.11 Line No.: 10 Column: g

Poles jointly owned by MID and TID. Conductor is property of TID. Excluded from total length on last page of 422.

Schedule Page: 422.12 Line No.: 10 Column: a

Cost and expenses already included in above lines.

Schedule Page: 422.12 Line No.: 13 Column: a

Includes roads and trails for all poles and tower lines.

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	ADDITIONS						
2	UNDERGROUND						
3							
4	Embarcadero GIS	North Transition Manhole	0.32	PVC-HDPE		1	1
5	North Transition Manhole	South Transition Manhole	2.85	Submarine		1	1
6	South Transition Manhole	Potrero GIS Termination	0.16	PVC-HDPE		1	1
7	Job order:#30846024,						
8	#31085843, #30605686,						
9	#30983382, #31085842,						
10	#31085845, #31090928,						
11	#31090930, #31103074,						
12	#31103076, #31085503,						
13	#31085840, #31085841,						
14	#31290909, #31290914						
15							
16	OVERHEAD						
17	Q678 Burford Five Points						
18	Panoche - Excelsior						
19	Structure 2/133	Excelsior Switching Station	0.15	TSP	13.00	2	2
20	Excelsior - Schindler						
21	Structure 28/134	Excelsior Switching Station	0.14	TSP	14.00	2	2
22	Job Order #31063217						
23							
24	Lathrop Irrigaion District 60V						
25	Kasson-Louise						
26	Structure 18/135A	LID Metering Station	0.02	TSP	50.00	1	1
27	Job Order #31101260						
28							
29	Tranquillity Switching Statin						
30	Panoche	Tranquillity Sw Sta #1	0.12	TSP	8.00	1	1
31	Panoche	Tranquillity Sw Sta #2	0.10	TSP	10.00	1	1
32	Tranquillity Sw Sta	Kearny	0.12	TSP	8.00	1	1
33	Tranquillity Sw Sta	Helm	0.10	TSP	10.00	1	1
34	Job Order #31031506						
35							
36	Q643W Mustang T-Line						
37	Gates	Mustang Sw Sta #1	0.11	TSP	9.00	1	1
38	Gates	Mustang Sw Sta #2	0.09	TSP	11.00	1	1
39	Mustang Sw Sta	Gregg	0.07	TSP	14.00	1	1
40	Mustang Sw Sta	McCall	0.08	TSP	13.00	1	1
41	Job Oder #31031500						
42							
43							
44	TOTAL		25.87		416.00	33	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	03/31/2017	End of 2016/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	Cal Flats Sw Sta 230kV						
2	Morro Bay	CAL Flats	0.16	TSP	6.00	1	1
3	CA Flats	Gates	0.15	TSP	7.00	1	1
4	Job Order #31067226						
5							
6	Q581 Henrietta Tline						
7	Leprino Switching Station	Kansas Solar Substation	0.05	TSP	40.00	1	1
8	Job Order #30968847						
9							
10	Q539 FRONTIER SOLAR						
11	3/12	Crow Creek SW STA	0.09	TSP	19.00	1	1
12	Crow Creek SW STA	3/12C	0.09	LDSP	19.00	1	1
13	Job Order #350855188						
14							
15	SILICON VALLEY RAPID						
16	5/42A	Railroad Court Sub	0.03	TSP	7.00	1	1
17	Job Order #30992643,						
18							
19							
20	RECONDUCTOR						
21	OVERHEAD						
22							
23	KERN-OLD RIVER #2 70 KV	21/318	11.10	Wood/lds	16.00	1	1
24	PO# 30848029						
25							
26	KERN-O.R #2 PANAMA SUB	11/138	1.12	Wood/lds	22.00	1	1
27	PO# 31161611						
28							
29	MESA - SISQUOC 115 KV	8/144	4.31	Wood/lds	19.00	1	1
30	PO# 30911535						
31							
32	San Luis #3 Tap 115kV						
33	Structure 122/549	Structure 1/13	0.03	Lattice Steel	5.00	1	1
34	Job Order #31000877						
35							
36	Morro Bay - Gates 230kV						
37	Structure 7/33	Structure 8/34	0.30	Lattice Steel	4.00	1	1
38	Job Order #31067917						
39							
40							
41							
42							
43							
44	TOTAL		25.87		416.00	33	33

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/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	REMOVALS						
2	Brighton - Oleum Junction	Structure 003/032	0.80	Lattice Steel	9.00	1	1
3	Structure 002/026						
4	Job Order #74001260						
5							
6	Johnson Wax Tap	Structure 0/1	0.40	Wood Pole	3.00	1	1
7	Structure 0/18						
8	Job Order #30997722						
9							
10	Modesto Energy Tap	Structure 0/10	0.50	Wood Pole	20.00	1	1
11	Structure 0/0						
12	Job Order #31007370						
13							
14	Mobil South Belridge Tap Idle.	Structure 002/35A	2.00	Wood Pole	17.00	1	1
15	Structure 000/003						
16	Job Order #30993231						
17							
18	Santa maria Cogen Tap	Substation Dead End	0.01	Wood Pole	23.00	1	1
19	Structure 000/005						
20	Job Order #30992080						
21							
22	Woodland Poly Tap	Structure 000/006	0.30	Wood Pole	20.00	1	1
23	Structure 000/001						
24	Job Order #31015019						
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		25.87		416.00	33	33

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
2500 kcmil	Copper	3 cables	230	2,790,742		238,509,403		241,300,145	4
1400 sqmm	Copper	3 cables	230						5
2500 kcmil	Copper	3 cables	230						6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
715	AAC	Vert Single	115		891,425	340,219		1,231,644	19
									20
715	AAC	Vert Single	115						21
									22
									23
									24
			60		737,051	19,989		757,040	25
715.5	AAC	Vertical							26
									27
									28
									29
1113	ACSS	Vert Sing	230		1,134,376	454,200		1,588,576	30
1113	ACSS		230						31
1113	ACSS		230						32
1113	ACSS		230						33
									34
									35
									36
1113	ACSS	Vertical	230		2,021,695	445,748		2,467,443	37
1113	ACSS	Vertical	230						38
1113	ACSS	Vertical	230						39
1113	ACSS	Vertical	230						40
									41
									42
									43
				2,808,848	17,525,734	252,278,690		272,613,272	44

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	Line No.
					928,149	187,421		1,115,570	1
1113	AAC	Vertical Hor	230						2
1113	AAC	Vertical Hor	230						3
									4
									5
									6
1113	AAC	Vert Single	115		920,786	424,751		1,345,537	7
									8
									9
									10
715	AAC	Vert Single	60		519,265	107,561		626,826	11
715	AAC	Vert Single	60						12
									13
									14
									15
397	AAC	Vert Single	115			1,894,205		1,894,205	16
									17
									18
									19
									20
									21
									22
477	ACSS	VERT/115 kV	70		4,264,406	4,268,496		8,532,902	23
									24
									25
477	ACSS	VERT/115 kV	70		627,101	1,823,385		2,450,486	26
									27
									28
1113	AAC	VERT/115 kV	115	18,106	1,173,549	3,472,491		4,664,146	29
									30
									31
									32
397	ACSR	Vert Single	115		224,910			224,910	33
									34
									35
									36
1113	AAC	Vert Single	230		2,621,275			2,621,275	37
									38
									39
									40
									41
									42
									43
				2,808,848	17,525,734	252,278,690		272,613,272	44

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
3/0	Cu	Vert Single	115		877,132			877,132	2
									3
									4
									5
397.5	AAC	Triangular	115		282,207			282,207	6
									7
									8
									9
4/0	AAC	Triangular	115		209,685			209,685	10
									11
									12
									13
4/0	AAC	Triangular	115		64,919	191,692		256,611	14
									15
									16
									17
397	AAC	Triangular	115		4,977	28,086		33,063	18
									19
									20
									21
4/0	AAC	Triangular	115		22,826	111,043		133,869	22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				2,808,848	17,525,734	252,278,690		272,613,272	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	03/31/2017	End of 2016/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	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	ALMADEN SUB, San Jose	Distribution	60.00	12.00	7.20
5	ALPAUGH SUB, Tulare	Distribution	115.00	12.00	
6	ALTO SUB, Mill Valley	Distribution	60.00	12.00	2.40
7	AMES DISTRIBUTION SUB, Mountain View	Distribution	115.00	12.00	7.20
8	ANDERSON SUB, Anderson	Distribution	60.00	12.00	2.40
9	ANGIOLA SUB, Kings	Distribution	70.00	12.00	7.20
10	ANITA SUB, Chico	Distribution	60.00	12.00	2.40
11	ANTELOPE SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
12	ANTLER SUB, Lakehead	Distribution	60.00	12.00	2.40
13	APPLE HILL SUB, Camino	Distribution	115.00	12.00	7.20
14	APPLE HILL SUB, Camino	Distribution	115.00	21.00	7.20
15	ARBUCKLE SUB, ARBUCKLE	Distribution	60.00	12.00	7.20
16	ARCATA SUB, Arcata	Distribution	60.00	12.00	2.40
17	ARCO SUB, Lost Hills	Transmission	230.00	70.00	13.20
18	ARVIN SUB, Arvin	Distribution	70.00	12.00	2.40
19	ASHLAN AVENUE SUB, Fresno	Distribution	230.00	12.00	7.20
20	ATASCADERO SUB, Atascadero	Distribution	115.00	12.00	7.20
21	ATLANTIC SUB, Roseville	Transmission	230.00	60.00	13.20
22	ATLANTIC SUB, Roseville	Transmission	230.00	115.00	13.20
23	ATWATER SUB, Atwater	Distribution	115.00	12.00	7.20
24	AUBERRY SUB, Auberry	Distribution	70.00	12.00	7.20
25	AVENA SUB, Escalon	Distribution	115.00	12.00	
26	AVENAL SUB, Avenal	Distribution	70.00	12.00	
27	BAHIA SUB, Benicia	Distribution	230.00	12.00	7.20
28	BAIR SUB, Redwood City	Transmission	115.00	60.00	13.20
29	BAIR SUB, Redwood City	Transmission	115.00	12.00	7.20
30	BAKERSFIELD SUB, Bakersfield	Distribution	230.00	21.00	7.20
31	BANGOR SUB, Bangor	Distribution	60.00	12.00	7.20
32	BARTON SUB, Fresno	Distribution	115.00	12.00	7.20
33	BASALT SUB, Napa	Distribution	60.00	12.00	2.40
34	BAY MEADOWS SUB, San Mateo	Distribution	115.00	21.00	7.20
35	BAY MEADOWS SUB, San Mateo	Distribution	115.00	12.00	7.20
36	BAYWOOD SUB, Morro Bay	Distribution	70.00	12.00	2.40
37	BEAR VALLEY SUB, Bear Valley	Distribution	70.00	21.00	7.20
38	BELL SUB, Auburn	Distribution	115.00	12.00	7.20
39	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	12.00	2.40
40	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	4.00	2.40

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	BELLEVUE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
2	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
3	BELMONT SUB, Belmont	Distribution	115.00	12.00	7.20
4	BERRENDA A SUB,	Distribution	70.00	4.00	2.40
5	BIG BASIN SUB, Santa Cruz	Distribution	60.00	12.00	
6	BIG MEADOWS SUB, Greenville	Distribution	60.00	44.00	2.40
7	BIOLA SUB, Biola	Distribution	70.00	12.00	2.40
8	BLACKWELL SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
9	BLUE LAKE SUB, Blue Lake	Distribution	60.00	12.00	2.40
10	BOGUE SUB, Yuba City	Distribution	115.00	12.00	7.20
11	BOLINAS SUB, Boninas	Distribution	60.00	12.00	7.20
12	BONITA SUB, Madera	Distribution	70.00	12.00	7.20
13	BORDEN SUB, Madera	Transmission	230.00	70.00	13.20
14	BORDEN SUB, Madera	Transmission	230.00	12.00	7.20
15	BOWLES SUB, Bowles	Distribution	70.00	12.00	2.40
16	BRENTWOOD SUB, Brentwood	Distribution	230.00	21.00	7.20
17	BRIDGEVILLE SUB, Bridgeville	Transmission	115.00	60.00	13.20
18	BRIGHTON SUB, Sacramento	Transmission	230.00	115.00	13.20
19	BRITTON SUB, Sunnyvale	Distribution	115.00	12.00	
20	BRUNSWICK SUB, Grass Valley	Distribution	115.00	12.00	7.20
21	BUELLTON SUB, Buellton /93427	Distribution	115.00	12.00	7.20
22	BUENA VISTA SUB, Salinas	Distribution	60.00	12.00	7.20
23	BULLARD SUB, Fresno	Distribution	115.00	12.00	7.20
24	BULLARD SUB, Fresno	Distribution	115.00	21.00	7.20
25	BURLINGAME SUB, Burlingame	Distribution	115.00	21.00	7.20
26	BUTTE SUB, Chico	Transmission	115.00	60.00	13.00
27	BUTTE SUB, Chico	Transmission	115.00	12.00	7.20
28	CABRILLO SUB, LOMPOC	Distribution	115.00	12.00	7.20
29	CADET SUB, Maricopa	Distribution	70.00	12.00	
30	CAL WATER SUB,	Distribution	115.00	12.00	7.20
31	CALAVERAS CEMENT SUB, San Andreas	Distribution	60.00	12.00	7.20
32	CALFLAX SUB, Huron	Distribution	70.00	12.00	2.40
33	CALIFORNIA AVE SUB, Fresno	Distribution	115.00	12.00	7.20
34	CALISTOGA SUB, Calistoga	Distribution	60.00	12.00	7.20
35	CALPELLA SUB, Calpella	Distribution	115.00	12.00	7.20
36	CAMDEN SUB, Riverdale	Distribution	70.00	12.00	2.40
37	CAMP EVERS SUB, Santa Cruz	Distribution	115.00	21.00	7.20
38	CAMPHORA SUB, Monterey	Distribution	60.00	12.00	7.20
39	CAMPHORA SUB, Monterey	Distribution	60.00	4.00	
40	CANAL SUB, Los Banos	Distribution	70.00	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	03/31/2017	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CANTUA SUB, Cantua Creek	Distribution	115.00	12.00	
2	CAPAY SUB, Orland	Distribution	60.00	12.00	2.40
3	CARBONA SUB, Tracy	Distribution	60.00	12.00	7.20
4	CARNATION SUB, Bakersfield	Distribution	70.00	21.00	7.20
5	CARNERAS SUB, Blackwells Corner	Distribution	70.00	12.00	7.20
6	CAROLANDS SUB, Hillsborough	Distribution	60.00	4.00	
7	CARQUINEZ SUB, Vallejo	Distribution	115.00	12.00	2.40
8	CARUTHERS SUB, Fresno	Distribution	70.00	12.00	2.40
9	CASCADE SUB, Pine Grove	Transmission	115.00	60.00	13.20
10	CASSIDY SUB, Madera	Distribution	70.00	12.00	2.40
11	CASTRO VALLEY SUB, Castro Valley	Distribution	230.00	12.00	
12	CASTROVILLE SUB, Castroville	Distribution	115.00	21.00	7.20
13	CATLETT SUB, Pleasant Grove	Distribution	60.00	12.00	
14	CAWELO B SUB, Famosa	Distribution	70.00	4.00	
15	CAYETANO SUB, Danville	Distribution	230.00	21.00	7.20
16	CAYUCOS SUB, Cayucos	Distribution	70.00	12.00	7.20
17	CHANNEL SUB, Stockton	Distribution	60.00	12.00	
18	CHARCA SUB, Wasco	Distribution	115.00	12.00	7.20
19	CHENEY SUB, Mendota	Distribution	115.00	12.00	7.20
20	CHEROKEE SUB, Stockton	Distribution	60.00	12.00	7.20
21	CHICO A SUB, Chico	Distribution	60.00	12.00	7.20
22	CHICO B SUB, Chico	Distribution	115.00	12.00	7.20
23	CHOLAME SUB, Cholame/93431	Distribution	70.00	12.00	2.40
24	CHOLAME SUB, Cholame/93431	Distribution	70.00	21.00	2.40
25	CHOWCHILLA SUB, Chowchilla	Distribution	115.00	12.00	7.20
26	CHRISTIE SUB, Hercules	Transmission	115.00	60.00	13.20
27	CLARK ROAD SUB, Paradise	Distribution	60.00	12.00	2.40
28	CLARKSVILLE SUB, Clarksville	Distribution	115.00	21.00	7.20
29	CLAY SUB, Ione	Distribution	60.00	12.00	2.40
30	CLAYTON SUB, Concord	Distribution	115.00	21.00	7.20
31	CLAYTON SUB, Concord	Distribution	115.00	12.00	7.20
32	CLEAR LAKE SUB, Finley	Distribution	60.00	12.00	2.40
33	CLOVERDALE SUB, Cloverdale	Distribution	115.00	12.00	7.20
34	CLOVIS SUB, Clovis	Distribution	115.00	12.00	7.20
35	CLOVIS SUB, Clovis	Distribution	115.00	21.00	7.20
36	COALINGA #1 SUB, Coalinga	Distribution	70.00	12.00	7.20
37	COALINGA #2 SUB, Coalinga	Distribution	70.00	12.00	2.40
38	COARSEGOLD SUB, Coursegold	Distribution	115.00	21.00	7.20
39	COBURN SUB, King City	Transmission	230.00	60.00	13.20
40	COLUMBUS SUB, Bakersfield	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	03/31/2017	End of 2016/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	COLUSA JUNCT SUB, Colusa	Distribution	60.00	12.00	7.20
2	COLUSA SUB, Colusa	Distribution	60.00	12.00	
3	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	60.00	13.20
4	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	115.00	13.20
5	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	21.00	7.20
6	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	21.00	6.60
7	COOLEY LANDING SUB, Palo Alto	Transmission	115.00	60.00	13.80
8	COPPERMINE SUB, Clovis	Distribution	70.00	12.00	2.40
9	COPUS SUB, Bakersfield	Distribution	70.00	12.00	
10	CORCORAN SUB, Corcoran	Transmission	115.00	70.00	13.20
11	CORCORAN SUB, Corcoran	Transmission	115.00	12.00	7.20
12	CORDELIA SUB, Cordelia	Distribution	115.00	12.00	7.20
13	CORDELIA SUB, Cordelia	Distribution	60.00	12.00	2.40
14	CORNING SUB, Corning	Distribution	60.00	12.00	2.40
15	CORONA SUB,	Distribution	115.00	12.00	7.20
16	CORRAL SUB, Bellota	Distribution	60.00	12.00	7.20
17	CORTINA SUB, Williams	Transmission	115.00	60.00	13.20
18	CORTINA SUB, Williams	Transmission	230.00	115.00	13.20
19	CORTINA SUB, Williams	Transmission	115.00	12.00	7.20
20	COTATI SUB, Cotati	Distribution	60.00	12.00	
21	COTTLE SUB, Oakdale	Distribution	230.00	17.00	
22	COTTONWOOD SUB, Cottonwood	Transmission	230.00	60.00	13.20
23	COTTONWOOD SUB, Cottonwood	Transmission	230.00	115.00	13.20
24	COTTONWOOD SUB, Cottonwood	Transmission	115.00	12.00	7.20
25	COUNTRY CLUB SUB, Stockton	Distribution	60.00	12.00	
26	COUNTRY CLUB SUB, Stockton	Distribution	60.00	4.00	
27	CRESSEY SUB, Merced	Distribution	115.00	21.00	
28	CURTIS SUB, Sonora	Distribution	115.00	18.00	
29	CUYAMA SUB, Cuyama	Distribution	70.00	12.00	
30	CUYAMA SUB, Cuyama	Distribution	70.00	21.00	7.20
31	CYMRIC SUB, McKitrick	Distribution	115.00	12.00	7.20
32	DAIRYLAND SUB, Chowchilla	Distribution	115.00	12.00	7.20
33	DALY CITY SUB, Daly City	Distribution	115.00	12.00	7.20
34	DAVIS SUB, Davis	Distribution	115.00	12.00	7.20
35	DEEPWATER SUB, W. Sactramento	Distribution	115.00	12.00	7.20
36	DEL MAR SUB, Rocklin	Distribution	60.00	21.00	7.20
37	DEL MAR SUB, Rocklin	Distribution	60.00	12.00	7.20
38	DEL MONTE SUB, Monterey	Transmission	115.00	60.00	13.20
39	DEL MONTE SUB, Monterey	Transmission	115.00	21.00	7.20
40	DERRICK SUB, Kettleman	Distribution	70.00	12.00	2.40

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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	DESCHUTES SUB, Palo Cedro	Distribution	60.00	12.00	7.20
2	DIAMOND SPRINGS SUB, Placerville	Distribution	115.00	12.00	7.20
3	DINUBA SUB, Dinuba	Distribution	70.00	12.00	7.20
4	DIVIDE SUB, Orcutt	Transmission	115.00	70.00	13.20
5	DIVIDE SUB, Orcutt	Transmission	70.00	12.00	2.40
6	DIVIDE SUB, Orcutt	Transmission	115.00	12.00	7.20
7	DIXON LANDING SUB,	Distribution	115.00	21.00	7.20
8	DIXON SUB, Dixon	Distribution	60.00	12.00	
9	DOLAN ROAD SUB, Moss Landing	Distribution	115.00	12.00	
10	DOS PALOS SUB, Dos Palos	Distribution	70.00	12.00	7.20
11	DUMBARTON SUB, Fremont	Distribution	115.00	12.00	
12	DUNBAR SUB, Glen Ellen	Distribution	60.00	12.00	
13	EAGLE ROCK SUB, Geysers	Transmission	115.00	60.00	
14	EAST GRAND SUB, So San Fran.	Distribution	115.00	12.00	7.20
15	EAST MARYSVILLE SUB, Marysville,	Distribution	115.00	12.00	7.20
16	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	60.00	
17	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	12.00	
18	EAST STOCKTON SUB, Stockton	Distribution	60.00	12.00	7.20
19	EAST STOCKTON SUB, Stockton	Distribution	60.00	4.00	
20	EASTSHORE SUB, Hayward	Transmission	230.00	115.00	
21	EDENVALE SUB, San Jose	Distribution	115.00	21.00	7.20
22	EDENVALE SUB, San Jose	Distribution	115.00	12.00	7.20
23	EDES SUB, Oakland	Distribution	115.00	12.00	7.20
24	EEL RIVER SUB, Ferndale	Distribution	60.00	12.00	7.20
25	EIGHT MILE SUB, Stockton	Distribution	230.00	21.00	7.20
26	EL CAPITAN SUB, Snelling	Distribution	115.00	12.00	
27	EL CAPITAN SUB, Snelling	Distribution	115.00	21.00	
28	EL CERRITO G SUB, El Cerrito	Distribution	115.00	12.00	
29	EL NIDO SUB, Merced	Distribution	115.00	12.00	7.20
30	EL PATIO SUB, Campbell	Distribution	115.00	12.00	7.20
31	EL PECO SUB, Madera	Distribution	70.00	12.00	
32	ELECTRA SUB,	Distribution	60.00	12.00	
33	ELK HILLS SUB, Valley Acres	Distribution	70.00	12.00	
34	ELK SUB, Elk	Distribution	60.00	12.00	2.40
35	EUREKA A SUB, Eureka	Distribution	60.00	12.00	7.20
36	EUREKA E SUB, Eureka	Distribution	60.00	12.00	
37	EVERGREEN SUB, San Jose	Transmission	115.00	60.00	13.20
38	EVERGREEN SUB, San Jose	Transmission	115.00	21.00	7.20
39	FAIRHAVEN SUB, Fairhaven	Distribution	60.00	12.00	7.20
40	FAIRVIEW SUB, Martinez	Distribution	115.00	21.00	12.00

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1	FAIRWAY SUB, Santa Maria	Distribution	115.00	12.00	7.20
2	FAMOSO SUB, Famosa	Distribution	115.00	12.00	
3	FELLOWS SUB, Fellows	Distribution	115.00	21.00	
4	FIGARDEN SUB, Fresno	Distribution	230.00	21.00	7.20
5	FIREBAUGH SUB, Firebaugh	Distribution	70.00	12.00	7.20
6	FITCH MOUNTAIN SUB, Healdsburg	Distribution	60.00	12.00	7.20
7	FLINT SUB, Auburn	Distribution	115.00	12.00	7.20
8	FMC SUB, San Jose	Distribution	115.00	12.00	7.20
9	FOOTHILL SUB, SLO	Distribution	115.00	12.00	2.40
10	FORESTHILL SUB, Foresthill,	Distribution	60.00	12.00	7.20
11	FORT BRAGG A SUB, Fort Bragg	Distribution	60.00	12.00	
12	FORT ORD SUB, Fort Ord	Distribution	60.00	21.00	7.20
13	FORT ORD SUB, Fort Ord	Distribution	60.00	12.00	2.40
14	FRANKLIN SUB, Hercules	Distribution	60.00	12.00	7.20
15	FREMONT SUB, Fremont	Distribution	115.00	12.00	7.20
16	FRENCH CAMP SUB, Stockton	Distribution	60.00	12.00	
17	FROGTOWN SUB, Angels Camp	Distribution	115.00	17.00	
18	FRUITVALE SUB, Bakersfield	Distribution	70.00	12.00	2.40
19	FULTON SUB, Fulton	Transmission	115.00	60.00	13.20
20	FULTON SUB, Fulton	Transmission	230.00	115.00	13.20
21	FULTON SUB, Fulton	Transmission	230.00	12.00	7.20
22	GABILAN SUB, Salinas	Distribution	115.00	12.00	7.20
23	GALLO SUB, Livingston	Distribution	115.00	12.00	
24	GANSNER SUB, Quincy	Distribution	60.00	12.00	7.20
25	GANSO SUB, Buttonwillow	Distribution	115.00	12.00	7.20
26	GARBERVILLE SUB, Garberville	Distribution	60.00	12.00	7.20
27	GATES SUB, Huron	Transmission	115.00	70.00	13.20
28	GATES SUB, Huron	Transmission	230.00	115.00	13.20
29	GATES SUB, Huron	Transmission	500.00	230.00	13.20
30	GATES SUB, Huron	Transmission	230.00	12.00	7.20
31	GATES SUB, Huron	Transmission	115.00	12.00	
32	GEYSERVILLE SUB, Geyserville	Distribution	60.00	12.00	2.40
33	GIFFEN SUB, San Joaquin	Distribution	70.00	12.00	2.40
34	GIRVAN SUB, Redding	Distribution	60.00	12.00	7.20
35	GLENN SUB, Orland	Transmission	230.00	60.00	13.20
36	GLENN SUB, Orland	Transmission	60.00	12.00	
37	GLENWOOD SUB, Menlo Park	Distribution	60.00	12.00	7.20
38	GLENWOOD SUB, Menlo Park	Distribution	60.00	4.00	
39	GOLD HILL SUB, Folsom	Transmission	115.00	60.00	13.20
40	GOLD HILL SUB, Folsom	Transmission	230.00	115.00	13.20

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1	GOLDTREE SUB, SLO	Distribution	115.00	12.00	7.20
2	GONZALES SUB, Gonzales	Distribution	60.00	12.00	
3	GOOSE LAKE SUB, Wasco	Distribution	115.00	12.00	7.20
4	GRAND ISLAND SUB, Ryde	Distribution	115.00	21.00	7.20
5	GRANT SUB, San Lorenzo	Distribution	115.00	12.00	7.20
6	GRASS VALLEY SUB, Grass Valley	Distribution	60.00	12.00	
7	GREEN VALLEY SUB, Watsonville	Transmission	115.00	60.00	
8	GREEN VALLEY SUB, Watsonville	Transmission	115.00	21.00	7.20
9	GREENBRAE SUB, Larkspur	Distribution	60.00	12.00	7.20
10	GUALALA SUB, Gualala	Distribution	60.00	12.00	2.40
11	GUERNSEY SUB, Hanford	Distribution	70.00	12.00	
12	GUSTINE SUB, Gustine	Distribution	60.00	12.00	7.20
13	HALF MOON BAY SUB, Half Moon Bay	Distribution	60.00	12.00	2.40
14	HAMMER SUB, Stockton	Distribution	60.00	12.00	7.20
15	HAMMONDS SUB, Fresno	Distribution	115.00	12.00	
16	HARDING SUB, Stockton	Distribution	60.00	4.00	
17	HARDWICK SUB, Layton	Distribution	70.00	12.00	7.20
18	HARRIS SUB, Eureka	Distribution	60.00	12.00	7.20
19	HARTER SUB, Yuba City	Distribution	60.00	12.00	7.20
20	HARTLEY SUB, Lakeport	Distribution	60.00	12.00	7.20
21	HATTON SUB, Carmel Valley	Distribution	60.00	12.00	2.40
22	HELM SUB, San Joaquin	Transmission	230.00	70.00	13.20
23	HENRIETTA SUB, Lamoore	Transmission	230.00	70.00	13.20
24	HENRIETTA SUB, Lamoore	Transmission	230.00	115.00	2.40
25	HENRIETTA SUB, Lamoore	Transmission	70.00	12.00	2.40
26	HERDLYN SUB, Tracy	Transmission	70.00	60.00	2.40
27	HERDLYN SUB, Tracy	Transmission	60.00	12.00	2.40
28	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20
29	HICKS SUB, San Jose	Distribution	230.00	21.00	7.20
30	HICKS SUB, San Jose	Distribution	230.00	12.00	7.20
31	HIGGINS SUB, Higgins Corner	Distribution	115.00	12.00	7.20
32	HIGHLANDS SUB, Clear Lake	Distribution	115.00	12.00	7.20
33	HIGHWAY SUB, Petaluma	Distribution	115.00	12.00	7.20
34	HOLLISTER SUB, Hollister	Distribution	115.00	21.00	7.20
35	HOLLISTER SUB, Hollister	Distribution	60.00	21.00	
36	HONCUT SUB, Honcut	Distribution	115.00	12.00	7.20
37	HOPLAND SUB, Hopland	Transmission	115.00	60.00	13.20
38	HOPLAND SUB, Hopland	Transmission	60.00	12.00	2.40
39	HORSESHOE SUB, Granite Bay	Distribution	115.00	12.00	7.20
40	HOWLAND ROAD SUB, Manteca	Distribution	115.00	12.00	7.20

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	13.80	
2	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	13.80	
3	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	12.00	7.20
4	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	2.00	
5	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	2.00	
6	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
7	HURON SUB, Huron	Distribution	70.00	12.00	2.40
8	IGNACIO SUB, Ignacio	Transmission	115.00	60.00	13.20
9	IGNACIO SUB, Ignacio	Transmission	230.00	115.00	13.20
10	IGNACIO SUB, Ignacio	Transmission	115.00	12.00	
11	IMHOFF SUB, Martinez	Distribution	115.00	12.00	7.20
12	IONE SUB, Ione	Distribution	60.00	12.00	7.20
13	JACINTO SUB, Willows	Distribution	60.00	12.00	7.20
14	JACOBS CORNER SUB, Lemoore	Distribution	70.00	12.00	2.40
15	JAMESON SUB, CORDELIA	Distribution	115.00	12.00	7.20
16	JANES CREEK SUB, Arcata	Distribution	60.00	12.00	7.20
17	JARVIS SUB, Union City	Distribution	115.00	12.00	7.20
18	JEFFERSON SUB, Redwood City	Transmission	230.00	60.00	13.20
19	JESSUP SUB, Anderson	Distribution	115.00	12.00	
20	JOLON SUB, King City	Distribution	60.00	12.00	
21	KASSON SUB, Tracy	Transmission	115.00	60.00	13.20
22	KELSO SUB, Tracy	Distribution	230.00	12.00	
23	KERMAN SUB, Kerman	Distribution	70.00	12.00	7.20
24	KERN OIL SUB, Bakersfield	Distribution	115.00	12.00	7.20
25	KERN PP DIST SUB, Bakersfield	Distribution	115.00	21.00	7.20
26	KERN PP SUB, Bakersfield	Transmission	115.00	70.00	13.20
27	KERN PP SUB, Bakersfield	Transmission	230.00	115.00	13.20
28	KESWICK SUB, Keswick	Distribution	60.00	12.00	2.40
29	KETTLEMAN HILLS SUB, Kettleman	Distribution	70.00	12.00	2.40
30	KING CITY SUB, King City	Distribution	60.00	12.00	
31	KINGSBURG SUB, Kingsburg	Transmission	115.00	70.00	13.80
32	KINGSBURG SUB, Kingsburg	Transmission	115.00	12.00	7.20
33	KIRKER SUB, Pittsburg	Distribution	115.00	21.00	7.20
34	KONOCTI SUB, Clear Lake	Distribution	60.00	12.00	2.40
35	LAKEVIEW SUB, Bakersfield	Distribution	70.00	12.00	2.40
36	LAKEVILLE SUB, Petaluma	Transmission	230.00	60.00	13.20
37	LAKEVILLE SUB, Petaluma	Transmission	230.00	115.00	13.20
38	LAKEVILLE SUB, Petaluma	Transmission	115.00	12.00	7.20
39	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	21.00	7.20
40	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	12.00	7.20

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1	LAMMERS SUB, TRACY	Distribution	115.00	12.00	7.20
2	LAMONT SUB, Bakersfield	Distribution	115.00	12.00	
3	LAS GALLINAS A SUB, Las Gallinas	Distribution	115.00	12.00	7.20
4	LAS PALMAS SUB, Fresno	Distribution	115.00	12.00	7.20
5	LAS POSITAS SUB, Livermore	Transmission	230.00	60.00	13.20
6	LAS POSITAS SUB, Livermore	Transmission	230.00	21.00	7.20
7	LAS PULGAS SUB, Redwood City	Distribution	60.00	4.00	2.40
8	LAWRENCE SUB, Sunnyvale	Distribution	115.00	12.00	7.20
9	LE GRAND SUB, Le Grand	Distribution	115.00	12.00	7.20
10	LEMOORE SUB, Armonia	Distribution	70.00	12.00	2.40
11	LERDO SUB, Bakersfield	Distribution	115.00	12.00	7.20
12	LINCOLN SUB, Lincoln	Distribution	115.00	12.00	7.20
13	LINDEN SUB, Linden	Distribution	60.00	12.00	2.40
14	LIVE OAK SUB, Live Oak	Distribution	60.00	12.00	
15	LIVERMORE SUB, Livermore	Distribution	60.00	12.00	2.40
16	LIVINGSTON SUB, Livingston	Distribution	115.00	12.00	7.20
17	LIVINGSTON SUB, Livingston	Distribution	70.00	12.00	
18	LLAGAS SUB, Gilroy	Distribution	115.00	21.00	12.00
19	LOCKEFORD SUB, Lockeford	Transmission	230.00	60.00	13.20
20	LOCKEFORD SUB, Lockeford	Transmission	115.00	21.00	7.20
21	LOCKHEED #1 SUB, Sunnyvale	Distribution	115.00	12.00	7.20
22	LOCKHEED #2 SUB, Sunnyvale	Distribution	115.00	12.00	
23	LODI SUB, Lodi	Distribution	60.00	12.00	2.40
24	LODI SUB, Lodi	Distribution	60.00	4.00	
25	LOGAN CREEK SUB, Willows	Distribution	230.00	21.00	
26	LONETREE SUB, Antioch	Distribution	230.00	21.00	7.20
27	LOS ALTOS SUB, Los Altos	Distribution	60.00	12.00	
28	LOS BANOS SUB, Los Banos	Transmission	230.00	70.00	13.20
29	LOS BANOS SUB, Los Banos	Transmission	500.00	230.00	13.80
30	LOS COCHES SUB, Greenfield	Distribution	60.00	12.00	
31	LOS ESTEROS SUB,	Transmission	230.00	115.00	12.00
32	LOS GATOS SUB, Los Gatos	Distribution	60.00	12.00	7.20
33	LOS MOLINOS SUB, Los Molinos	Distribution	60.00	12.00	7.20
34	LOS OSITOS SUB, Monterey	Distribution	60.00	21.00	7.20
35	LOYOLA SUB, Loyola	Distribution	60.00	12.00	7.20
36	LOYOLA SUB, Loyola	Distribution	60.00	4.00	2.40
37	LUCERNE SUB, Lucerne	Distribution	115.00	12.00	7.20
38	MABURY SUB, San Jose	Distribution	60.00	12.00	2.40
39	MABURY SUB, San Jose	Distribution	115.00	12.00	7.20
40	MADERA SUB, Madera	Distribution	70.00	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	MADISON SUB, Madison	Distribution	60.00	12.00	7.20
2	MADISON SUB, Madison	Distribution	115.00	12.00	
3	MAGUNDEN SUB, Bakersfield	Distribution	115.00	12.00	7.20
4	MAGUNDEN SUB, Bakersfield	Distribution	115.00	21.00	7.20
5	MALAGA SUB, Fresno	Distribution	115.00	12.00	7.20
6	MANCHESTER SUB, Fresno	Distribution	115.00	12.00	7.20
7	MANTECA SUB, Manteca	Transmission	115.00	60.00	12.80
8	MANTECA SUB, Manteca	Transmission	115.00	17.00	
9	MARICOPA SUB, Maricopa	Distribution	70.00	12.00	2.40
10	MARIPOSA SUB, Mariposa	Distribution	70.00	21.00	
11	MARTELL SUB, Martell	Distribution	60.00	12.00	2.40
12	MARYSVILLE SUB, Marysville	Distribution	60.00	12.00	
13	MAXWELL SUB, Maxwell	Distribution	60.00	12.00	
14	MCARTHUR SUB, McArthur	Distribution	60.00	12.00	2.40
15	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
16	MCCALL SUB, Selma	Transmission	115.00	12.00	7.20
17	MCDONALD-MCDONALDISLAND SUB, Stockton	Distribution	60.00	4.00	2.40
18	MCFARLAND SUB, McFarland	Distribution	70.00	12.00	7.20
19	MCKEE SUB, San Jose	Distribution	115.00	12.00	7.20
20	MCKITTRICK SUB, MCKITTRICK	Distribution	70.00	12.00	
21	MCMULLIN SUB, Fresno	Distribution	230.00	12.00	7.20
22	MEADOW LANE SUB, Concord	Distribution	115.00	21.00	7.20
23	MENDOCINO SUB, Redwood Valley	Transmission	115.00	60.00	13.20
24	MENDOCINO SUB, Redwood Valley	Transmission	60.00	12.00	2.40
25	MENDOTA SUB, Mendota	Transmission	115.00	70.00	12.00
26	MENDOTA SUB, Mendota	Transmission	115.00	12.00	7.20
27	MENLO SUB, Menlo Park	Distribution	60.00	12.00	7.20
28	MENLO SUB, Menlo Park	Distribution	60.00	4.00	
29	MERCED SUB, Merced	Transmission	115.00	70.00	6.60
30	MERCED SUB, Merced	Transmission	115.00	12.00	7.20
31	MERCED SUB, Merced	Transmission	115.00	21.00	7.20
32	MERIDIAN SUB, Meridian	Distribution	60.00	12.00	
33	MESA SUB, Nipomo	Transmission	230.00	115.00	13.20
34	MESA SUB, Nipomo	Transmission	230.00	12.00	
35	METCALF SUB, San Jose	Transmission	500.00	230.00	13.80
36	METCALF SUB, San Jose	Transmission	230.00	115.00	13.20
37	METTLER SUB, Stockton	Distribution	60.00	12.00	
38	MIDDLETOWN SUB, Middletown	Distribution	60.00	12.00	7.20
39	MIDWAY SUB, Buttonwillow	Transmission	230.00	115.00	13.20
40	MIDWAY SUB, Buttonwillow	Transmission	500.00	230.00	13.80

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	MIDWAY SUB, Buttonwillow	Transmission	115.00	12.00	7.20
2	MILLBRAE SUB, Millbrae	Transmission	115.00	60.00	13.80
3	MILLBRAE SUB, Millbrae	Transmission	115.00	12.00	
4	MILLBRAE SUB, Millbrae	Transmission	60.00	4.00	
5	MILPITAS SUB, Milpitas	Distribution	115.00	21.00	7.20
6	MILPITAS SUB, Milpitas	Distribution	115.00	12.00	7.20
7	MIRABEL SUB, Forestville	Distribution	60.00	12.00	
8	MI-WUK SUB, Sugarpine	Distribution	115.00	17.00	
9	MOLINO SUB, Sebastopol	Distribution	60.00	12.00	7.20
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	MORAGA SUB, Orinda	Transmission	230.00	115.00	13.20
19	MORAGA SUB, Orinda	Transmission	115.00	12.00	
20	MORGAN HILL SUB, Morgan Hill	Distribution	115.00	21.00	7.20
21	MORMON SUB, Stockton	Distribution	60.00	12.00	7.20
22	MORRO BAY PP SWYD, Morro Bay	Transmission	230.00	115.00	13.20
23	MORRO BAY PP SWYD, Morro Bay	Transmission	115.00	12.00	7.20
24	MOSHER SUB, Stockton	Distribution	60.00	21.00	7.20
25	MOSS LANDING PP SUB, Moss Landing	Transmission	230.00	115.00	13.20
26	MOSS LANDING PP SUB, Moss Landing	Transmission	500.00	230.00	13.80
27	MOUNTAIN VIEW SUB, Mt. View	Distribution	115.00	12.00	7.20
28	MT. EDEN SUB, Hayward	Distribution	115.00	12.00	7.20
29	MT. QUARRIES SUB, Cool	Distribution	60.00	12.00	7.20
30	NAPA SUB, Napa	Distribution	60.00	12.00	
31	NARROWS SUB,	Distribution	60.00	21.00	7.20
32	NEW KEARNEY SUB, FRESNO	Transmission	230.00	70.00	13.20
33	NEWARK DIST SUB, Fremont	Distribution	230.00	21.00	7.20
34	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
35	NEWARK SUB, Fremont	Transmission	115.00	60.00	13.20
36	NEWARK SUB, Fremont	Transmission	115.00	12.00	7.20
37	NEWBURG SUB, Fortuna	Distribution	60.00	12.00	2.40
38	NEWHALL SUB, Firebaugh	Distribution	115.00	12.00	7.20
39	NEWMAN SUB, Newman	Distribution	60.00	12.00	7.20
40	NORCO SUB, Bakersfield	Distribution	115.00	12.00	7.20

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/31/2017	Year/Period of Report End of 2016/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NORD SUB, Chico	Distribution	115.00	12.00	7.20
2	NORTECH SUB, San Jose	Distribution	115.00	21.00	7.20
3	NORTH DUBLIN SUB, Pleasanton	Distribution	230.00	21.00	12.00
4	NORTH TOWER SUB, Vallejo	Distribution	115.00	12.00	7.20
5	NORTH TOWER SUB, Vallejo	Distribution	115.00	25.00	7.20
6	NOTRE DAME SUB, Chico	Distribution	115.00	12.00	7.20
7	NOVATO SUB, Novato	Distribution	60.00	12.00	7.20
8	OAKHURST SUB, Oakhurst	Distribution	115.00	12.00	2.40
9	OAKLAND C (OAKLAND PP) SUB, Oakland	Distribution	115.00	12.00	7.20
10	OAKLAND D SUB, Oakland	Distribution	115.00	12.00	7.20
11	OAKLAND J SUB, Oakland	Distribution	115.00	12.00	7.20
12	OAKLAND K (CLAREMONT) SUB, Oakland	Distribution	115.00	12.00	6.60
13	OAKLAND L SUB, Oakland	Distribution	115.00	12.00	7.20
14	OAKLAND X SUB, Oakland	Distribution	115.00	12.00	7.20
15	OCEANO SUB, Oceano	Distribution	115.00	12.00	7.20
16	OILFIELDS SUB, San Ardo	Distribution	60.00	12.00	
17	OLD KEARNEY SUB, Fresno	Distribution	70.00	12.00	13.20
18	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	2.40
19	OLD RIVER SUB, Knob Hill	Distribution	115.00	12.00	7.20
20	OLETA SUB, Plymouth	Distribution	60.00	12.00	2.40
21	OLIVEHURST SUB, Olivehurst	Distribution	115.00	12.00	7.20
22	OREGON TRAIL SUB, Redding	Distribution	115.00	12.00	7.20
23	OREGON TRAIL SUB, Redding	Distribution	60.00	12.00	2.40
24	ORLAND B SUB, Orland	Distribution	60.00	12.00	2.40
25	ORO FINO SUB, Magalia	Distribution	60.00	12.00	2.40
26	ORO LOMA SUB, Dos Palos	Transmission	115.00	70.00	13.20
27	ORO LOMA SUB, Dos Palos	Transmission	70.00	12.00	2.40
28	ORO LOMA SUB, Dos Palos	Transmission	115.00	12.00	
29	OROSI SUB, Orosi	Distribution	70.00	12.00	7.20
30	OROVILLE SUB, Oroville	Distribution	60.00	12.00	7.20
31	OROVILLE SUB, Oroville	Distribution	60.00	4.00	2.40
32	ORTIGA SUB, Los Banos	Distribution	70.00	12.00	2.40
33	PACIFICA SUB, Pacifica	Distribution	60.00	12.00	
34	PALERMO SUB, Palermo	Transmission	230.00	60.00	
35	PALERMO SUB, Palermo	Transmission	230.00	115.00	13.20
36	PALMER SUB, Sisquat	Distribution	115.00	12.00	7.20
37	PANAMA SUB, Bakersfield	Distribution	70.00	21.00	7.20
38	PANOCHE SUB, Mendota	Transmission	230.00	115.00	13.20
39	PANOCHE SUB, Mendota	Transmission	230.00	12.00	7.20
40	PANORAMA SUB, Anderson	Distribution	115.00	12.00	

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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	PARADISE SUB, Paradise	Distribution	60.00	12.00	7.20
2	PARADISE SUB, Paradise	Distribution	115.00	12.00	
3	PARKWAY SUB, Vallejo	Distribution	230.00	12.00	7.20
4	PARLIER SUB, Parlier	Distribution	115.00	12.00	7.20
5	PASO ROBLES SUB, Paso Robles	Distribution	70.00	12.00	2.40
6	PAUL SWEET SUB, Santa Cruz	Distribution	115.00	21.00	7.20
7	PEABODY SUB, Fairfield	Distribution	230.00	21.00	7.20
8	PEACHTON SUB, Gridley	Distribution	60.00	12.00	2.40
9	PEASE SUB, Tierra Buena	Transmission	115.00	60.00	13.20
10	PEASE SUB, Tierra Buena	Transmission	115.00	12.00	
11	PENNGROVE SUB, Penngrove	Distribution	115.00	12.00	
12	PENRYN SUB, Penryn	Distribution	60.00	12.00	7.20
13	PEORIA SUB, Jamestown	Distribution	115.00	18.00	
14	PETALUMA C SUB, Petaluma	Distribution	60.00	12.00	
15	PIERCY SUB, San Jose	Distribution	115.00	21.00	7.20
16	PINE GROVE SUB, Pine Grove	Distribution	60.00	12.00	2.40
17	PINEDALE SUB, FRESNO	Distribution	115.00	21.00	7.20
18	PITTSBURG PP SUB,	Transmission	230.00	115.00	13.20
19	PLACER SUB, Auburn	Transmission	115.00	60.00	
20	PLACER SUB, Auburn	Transmission	115.00	12.00	
21	PLACERVILLE SUB, Placerville	Distribution	115.00	12.00	7.20
22	PLACERVILLE SUB, Placerville	Distribution	115.00	21.00	
23	PLAINFIELD SUB, Davis	Distribution	60.00	12.00	2.40
24	PLEASANT GROVE SUB, Pleasant Grove	Distribution	60.00	21.00	7.20
25	PLUMAS SUB, Wheatland	Distribution	60.00	21.00	7.20
26	PLUMAS SUB, Wheatland	Distribution	60.00	12.00	7.20
27	POINT MORETTI SUB, Davenport	Distribution	60.00	12.00	2.40
28	POINT PINOLE SUB, Richmond	Distribution	115.00	12.00	6.60
29	POSO MOUNTAIN SUB, Kern	Distribution	115.00	21.00	
30	PRUNEDALE SUB, Prunedale	Distribution	115.00	12.00	7.20
31	PUEBLO SUB, Napa	Distribution	115.00	12.00	
32	PUEBLO SUB, Napa	Distribution	115.00	21.00	
33	PURISIMA SUB, Lompoc	Distribution	115.00	12.00	7.20
34	PUTAH CREEK SUB, Winters	Distribution	115.00	12.00	
35	RACE TRACK SUB, Jamestown	Distribution	115.00	17.00	
36	RADUM SUB, Pleasanton	Distribution	60.00	12.00	
37	RAINBOW SUB, Sanger	Distribution	115.00	12.00	7.20
38	RALSTON SUB, Belmont	Distribution	60.00	12.00	
39	RANCHERS COTTON SUB, Fresno	Distribution	115.00	12.00	7.20
40	RAVENSWOOD SUB, Menlo Park	Transmission	230.00	115.00	13.20

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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	RAWSON SUB, Red Bluff	Distribution	60.00	12.00	2.40
2	RED BLUFF SUB, Red Bluff	Distribution	60.00	12.00	2.40
3	REDBUD SUB, Clearlake Oaks	Distribution	115.00	12.00	7.20
4	REDWOOD CITY SUB, Redwood City	Distribution	60.00	12.00	7.20
5	REDWOOD CITY SUB, Redwood City	Distribution	60.00	4.00	
6	REEDLEY SUB, Reedley	Transmission	115.00	70.00	13.20
7	REEDLEY SUB, Reedley	Transmission	115.00	12.00	7.20
8	REEDLEY SUB, Reedley	Transmission	70.00	12.00	2.40
9	RENFRO SUB, BAKERSFIELD	Distribution	115.00	12.00	7.20
10	RESEARCH SUB, San Ramon	Distribution	230.00	21.00	7.20
11	RESERVATION ROAD SUB, Salinas	Distribution	60.00	12.00	2.40
12	RICE SUB, Princeton	Distribution	60.00	12.00	4.16
13	RICHMOND R SUB, Richmond	Distribution	115.00	12.00	7.20
14	RINCON SUB, Santa Rosa	Distribution	115.00	12.00	
15	RIO BRAVO SUB, Shafter	Distribution	115.00	12.00	7.20
16	RIO DELL SUB, Rio Dell	Distribution	60.00	12.00	
17	RIO OSO SUB, Rio Oso	Transmission	230.00	115.00	13.20
18	RIPON SUB, Ripon	Distribution	115.00	17.00	
19	RISING RIVER SUB, Cassell,	Distribution	60.00	12.00	2.40
20	RIVER OAKS SUB, San Jose	Distribution	115.00	21.00	7.20
21	RIVERBANK SUB, Escalon	Distribution	115.00	12.00	
22	ROB ROY SUB, Watsonville	Distribution	115.00	21.00	7.20
23	ROCKLIN SUB, Rocklin	Distribution	60.00	12.00	7.20
24	ROSEDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
25	ROSSMOOR SUB, Walnut Creek	Distribution	230.00	12.00	
26	ROUGH & READY ISLAND SUB, Stockton	Distribution	60.00	12.00	7.20
27	ROUND MOUNTAIN SUB, Rd Mtn	Transmission	500.00	230.00	13.80
28	SALADO SUB, Patterson	Transmission	115.00	60.00	13.20
29	SALINAS SUB, Salinas	Transmission	115.00	60.00	13.20
30	SALINAS SUB, Salinas	Transmission	115.00	12.00	7.20
31	SALMON CREEK SUB, Bodega Bay	Distribution	60.00	12.00	2.40
32	SAN ARDO SUB, San Ardo	Distribution	60.00	12.00	
33	SAN BENITO SUB, San Benito	Distribution	115.00	21.00	7.20
34	SAN BERNARD SUB, Lamont	Distribution	70.00	12.00	2.40
35	SAN CARLOS SUB, San Carlos	Distribution	60.00	12.00	7.20
36	SAN CARLOS SUB, San Carlos	Distribution	60.00	4.00	2.40
37	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	230.00	115.00	13.20
38	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	115.00	12.00	7.20
39	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	60.00	
40	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	230.00	115.00	

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SUBSTATIONS

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1	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	12.00	
2	SAN FRAN P-HUNTERS POINT SUB, San Francisco	Distribution	115.00	12.00	
3	SAN FRAN X (MISSION) SUB, San Francisco	Distribution	115.00	12.00	7.20
4	SAN FRAN Y (LARKIN) SUB, San Francisco	Distribution	115.00	12.00	7.20
5	SAN FRAN Z (Embarcadero), San Francisco	Distribution	230.00	34.50	7.20
6	SAN JOAQUIN SUB, San Joaquin	Distribution	70.00	12.00	7.20
7	SAN JOSE A SUB, San Jose	Distribution	115.00	4.00	7.20
8	SAN JOSE A SUB, San Jose	Distribution	115.00	12.00	
9	SAN JOSE B SUB, San Jose	Distribution	115.00	12.00	7.20
10	SAN LEANDRO U SUB, San Leandro	Distribution	115.00	12.00	
11	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	70.00	13.20
12	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	12.00	7.20
13	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
14	SAN MATEO SUB, San Mateo	Transmission	115.00	60.00	
15	SAN MATEO SUB, San Mateo	Transmission	115.00	21.00	
16	SAN MATEO SUB, San Mateo	Transmission	60.00	4.00	
17	SAN MIGUEL SUB, San Miguel	Distribution	70.00	12.00	7.20
18	SAN PABLO SUB, Richmond	Distribution	115.00	12.00	7.20
19	SAN RAFAEL SUB, San Rafael	Distribution	115.00	12.00	
20	SAN RAMON SUB, San Ramon	Transmission	230.00	60.00	13.20
21	SAN RAMON SUB, San Ramon	Transmission	230.00	21.00	12.00
22	SANGER SUB, Fresno	Transmission	115.00	70.00	6.60
23	SANGER SUB, Fresno	Transmission	115.00	12.00	7.20
24	SANTA MARIA SUB, Santa Maria	Distribution	115.00	12.00	7.20
25	SANTA NELLA SUB, Santa Nella	Distribution	70.00	12.00	2.40
26	SANTA RITA SUB, Dos Palos	Distribution	70.00	12.00	2.40
27	SANTA ROSA A SUB, Santa Rosa	Distribution	115.00	12.00	7.20
28	SANTA YNEZ SUB, Santa Maria	Distribution	115.00	12.00	7.20
29	SARATOGA SUB, Saratoga	Distribution	230.00	12.00	7.20
30	SAUSALITO SUB, Sausalito	Distribution	60.00	12.00	2.40
31	SAUSALITO SUB, Sausalito	Distribution	60.00	4.00	
32	SCHINDLER SUB, Five Points	Transmission	115.00	70.00	13.20
33	SCHINDLER SUB, Five Points	Transmission	115.00	12.00	7.20
34	SEMITROPIC SUB, Wasco	Transmission	115.00	70.00	13.80
35	SEMITROPIC SUB, Wasco	Transmission	115.00	12.00	7.20
36	SERRAMONTE SUB, Daly City	Distribution	115.00	12.00	
37	SHAFTER SUB, Shafter	Distribution	115.00	12.00	7.20
38	SHARON SUB, Chowchilla	Distribution	115.00	12.00	
39	SHEPARD SUB, Clovis	Distribution	115.00	21.00	7.20
40	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	21.00	7.20

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1	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	12.00	7.20
2	SHREDDER SUB, Redwood City	Distribution	115.00	4.00	6.60
3	SILVERADO SUB, St. Helena	Distribution	115.00	21.00	
4	SISQUOC SUB, Orcutt	Distribution	115.00	12.00	7.20
5	SMYRNA SUB, Wasco	Distribution	115.00	12.00	7.20
6	SNEATH LANE SUB, San Bruno	Distribution	60.00	12.00	2.40
7	SOBRANTE SUB, Orinda	Transmission	230.00	115.00	
8	SOBRANTE SUB, Orinda	Transmission	115.00	12.00	7.20
9	SOLEDAD SUB, Soledad	Transmission	115.00	60.00	
10	SOLEDAD SUB, Soledad	Transmission	60.00	12.00	
11	SONOMA A SUB, Sonoma	Distribution	115.00	12.00	
12	SOUTH BAY #1 & #2 SUB, Tracy	Distribution	60.00	4.00	
13	SPANISH CREEK SUB,	Distribution	60.00	44.00	
14	SPENCE SUB, Salinas	Distribution	60.00	12.00	
15	SRI SUB, Menlo Park	Distribution	60.00	12.00	
16	STAFFORD SUB, Novato	Distribution	60.00	12.00	
17	STAGG SUB, Stockton	Transmission	230.00	60.00	13.20
18	STAGG SUB, Stockton	Transmission	230.00	21.00	7.20
19	STAGG SUB, Stockton	Transmission	60.00	12.00	2.40
20	STELLING SUB, Cupertino	Distribution	115.00	12.00	7.20
21	STILLWATER STA SUB, Project City	Distribution	60.00	12.00	2.40
22	STOCKDALE SUB, Bakersfield	Distribution	230.00	21.00	7.20
23	STOCKDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
24	STOCKTON A SUB, Stockton	Transmission	115.00	12.00	
25	STOCKTON A SUB, Stockton	Transmission	60.00	4.00	
26	STONE CORRAL SUB, Woodlake	Distribution	70.00	12.00	2.40
27	STONE SUB, San Jose	Distribution	115.00	12.00	7.20
28	STOREY SUB, Madera	Distribution	230.00	12.00	7.20
29	STROUD SUB, Helm	Distribution	70.00	12.00	2.40
30	SUISUN SUB, Fairfield	Distribution	115.00	12.00	7.20
31	SUNOL SUB, Sunol	Distribution	60.00	12.00	7.20
32	SWIFT SUB, San Jose	Distribution	115.00	21.00	7.20
33	SYCAMORE CREEK SUB, Chico	Distribution	115.00	12.00	
34	TABLE MOUNTAIN SUB, Oroville	Transmission	230.00	115.00	
35	TABLE MOUNTAIN SUB, Oroville	Transmission	500.00	230.00	13.80
36	TAFT SUB, Taft	Transmission	115.00	70.00	13.20
37	TAFT SUB, Taft	Transmission	115.00	12.00	7.20
38	TAMARACK SUB, Soda Springs	Distribution	60.00	12.00	7.20
39	TASSAJARA SUB, Danville	Distribution	230.00	21.00	7.20
40	TEJON SUB, Leboc	Distribution	70.00	12.00	2.40

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	TEMBLOR SUB, McKittrick	Distribution	115.00	12.00	2.40
2	TEMPLETON SUB, TEMPLETON	Transmission	230.00	70.00	13.20
3	TEMPLETON SUB, TEMPLETON	Transmission	230.00	21.00	7.20
4	TESLA SUB, Tracy	Transmission	230.00	115.00	13.20
5	TESLA SUB, Tracy	Transmission	500.00	230.00	13.20
6	TEVIS SUB, Oildale	Distribution	115.00	21.00	7.20
7	TIDEWATER SUB, Martinez	Distribution	230.00	21.00	
8	TIVY VALLEY SUB, Fresno	Distribution	70.00	12.00	7.20
9	TRACY SUB, Tracy	Distribution	115.00	12.00	4.16
10	TRES VIAS SUB, Oroville	Distribution	60.00	12.00	7.20
11	TRIMBLE SUB, San Jose	Distribution	115.00	12.00	7.20
12	TRIMBLE SUB, San Jose	Distribution	115.00	21.00	7.20
13	TRINITY SUB, Weaverville	Transmission	115.00	60.00	13.20
14	TULARE LAKE SUB, Kettleman	Distribution	70.00	12.00	2.40
15	TULUCAY SUB, Napa	Transmission	230.00	60.00	13.20
16	TULUCAY SUB, Napa	Transmission	60.00	12.00	7.20
17	TUPMAN SUB, Tupman	Distribution	115.00	12.00	7.20
18	TWISSELMAN SUB, Blackwell Corners	Distribution	70.00	12.00	7.20
19	TYLER SUB, Red Bluff	Distribution	60.00	12.00	2.40
20	UKIAH SUB, Ukiah	Distribution	115.00	12.00	7.20
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	VALLEY HOME SUB, Valley Home	Distribution	60.00	17.00	
28	VALLEY HOME SUB, Valley Home	Distribution	115.00	17.00	
29	VALLEY SPRINGS SUB, Valley Springs	Transmission	230.00	60.00	13.20
30	VALLEY VIEW SUB, El Sobrante	Distribution	115.00	12.00	
31	VASCO SUB, Livermore	Distribution	60.00	12.00	
32	VASONA SUB, Los Gatos	Distribution	230.00	12.00	7.20
33	VICTOR SUB, Lodi	Distribution	60.00	12.00	2.40
34	VIEJO SUB, Monterey	Distribution	60.00	21.00	7.20
35	VIERRA SUB, Lathrop	Distribution	115.00	17.00	7.20
36	VINEYARD SUB, Pleasanton	Distribution	230.00	21.00	7.20
37	VOLTA #1PH SUB, Shingletown	Distribution	60.00	12.00	2.40
38	WAHTOKE SUB, Reedley	Distribution	115.00	12.00	7.20
39	WASCO SUB, Wasco	Distribution	70.00	12.00	2.40
40	WATERLOO SUB, Stockton	Distribution	60.00	12.00	2.40

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	03/31/2017	End of 2016/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	WATSONVILLE SUB, Watsonville	Distribution	60.00	12.00	7.20
2	WATSONVILLE SUB, Watsonville	Distribution	60.00	4.00	
3	WEBER SUB, Stockton	Transmission	230.00	60.00	13.20
4	WEBER SUB, Stockton	Transmission	60.00	12.00	7.20
5	WEBER SUB, Stockton	Transmission	230.00	12.00	7.20
6	WEEDPATCH SUB, Weedpatch	Distribution	70.00	12.00	7.20
7	WELLFIELD SUB, Lamont	Distribution	70.00	12.00	2.40
8	WEST FRESNO SUB, Fresno	Distribution	115.00	12.00	7.20
9	WEST LANE SUB, Stockton	Distribution	60.00	12.00	7.20
10	WEST SACRAMENTO SUB, WEST SACRAMENTO	Distribution	115.00	12.00	7.20
11	WESTLEY SUB, Westley	Distribution	60.00	12.00	2.40
12	WESTPARK SUB, Bakersfield	Distribution	115.00	12.00	7.20
13	WHEATLAND SUB, Wheatland	Distribution	60.00	12.00	7.20
14	WHEELER RIDGE SUB, Bakersfield	Transmission	115.00	70.00	13.20
15	WHEELER RIDGE SUB, Bakersfield	Transmission	230.00	70.00	13.20
16	WHEELER RIDGE SUB, Bakersfield	Transmission	70.00	12.00	2.40
17	WHISMAN SUB, Mt. View	Distribution	115.00	12.00	7.20
18	WILLIAMS SUB, Williams	Distribution	60.00	12.00	7.20
19	WILLITS A SUB, Willits	Distribution	60.00	12.00	2.40
20	WILLOW CREEK SUB, Willow Creek	Distribution	60.00	12.00	2.40
21	WILLOW PASS SUB, Pittsburg	Distribution	115.00	21.00	7.20
22	WILLOW PASS SUB, Pittsburg	Distribution	60.00	12.00	2.40
23	WILLOWS A SUB, Willows	Distribution	60.00	12.00	
24	WILSON SUB, Merced	Transmission	230.00	115.00	13.20
25	WILSON SUB, Merced	Transmission	115.00	12.00	
26	WOLFE SUB, Cupertino	Distribution	115.00	12.00	
27	WOODCHUCK SUB, Wilson Village	Distribution	70.00	21.00	
28	WOODLAND SUB, Woodland	Distribution	115.00	12.00	7.20
29	WOODSIDE SUB, Woodside	Distribution	60.00	12.00	
30	WOODWARD SUB, Fresno	Distribution	115.00	21.00	7.20
31	WRIGHT SUB, Los Banos	Distribution	70.00	12.00	2.40
32	WYANDOTTE SUB, Oroville	Distribution	115.00	12.00	7.20
33	ZACA SUB, Santa Maria	Distribution	115.00	12.00	7.20
34	ZAMORA SUB, Zamora	Distribution	115.00	12.00	
35	rounding issues in column f				
36	Total Distribution and Transmission substations		82590.00	18873.10	4083.52
37	Transmission only substations		24120.00	10990.00	1341.80
38					
39	Combined Dist Subs < 10 MVA (132 substations)				
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	1		1.00000			1
90	2		2.00000			2
27	2		2.00000			3
60	2		2.00000			4
41	2		1.00000			5
49	4	1	2.00000			6
30	1		1.00000			7
19	3	1	1.00000			8
16	1		1.00000			9
38	2		2.00000			10
11	1		1.00000			11
11	3	1	1.00000			12
16	1		1.00000			13
16	1		1.00000			14
27	4	1	2.00000			15
60	2		2.00000			16
360	6	1	2.00000			17
11	3		1.00000			18
210	3		3.00000			19
30	1		1.00000			20
334	4	1	2.00000			21
840	2		2.00000			22
90	2		2.00000			23
25	2		2.00000			24
16	3	1	1.00000			25
16	1		1.00000			26
112	2		2.00000			27
80	3		1.00000			28
45	1		1.00000			29
225	3		3.00000			30
13	1		1.00000			31
120	3		3.00000			32
39	4		2.00000			33
90	2		2.00000			34
75	2		2.00000			35
16	1		1.00000			36
13	1		1.00000			37
57	2		2.00000			38
57	3		3.00000			39
16	6	1	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	03/31/2017	End of 2016/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)	
70	3		3.00000			1
400	2		Sync Cond	1	40	2
135	3		3.00000			3
16	2		2.00000			4
11	3	1	1.00000			5
15	3		1.00000			6
20	3		1.00000			7
13	1		1.00000			8
13	3	1	1.00000			9
90	2		2.00000			10
13	1		1.00000			11
16	1		1.00000			12
400	2		2.00000			13
30	1		1.00000			14
20	3		1.00000			15
195	3		3.00000			16
90	3	1	1.00000			17
840	2		2.00000			18
120	3		3.00000			19
90	3		3.00000			20
21	2		2.00000			21
76	3		3.00000			22
90	2		2.00000			23
45	1		1.00000			24
30	1		1.00000			25
90	3	1	1.00000			26
46	2		2.00000			27
11	1		1.00000			28
20	3		1.00000			29
30	1		1.00000			30
15	3		1.00000			31
19	3		1.00000			32
135	3		3.00000			33
21	3	1	1.00000			34
16	1		1.00000			35
41	2		2.00000			36
90	2		2.00000			37
11	1		1.00000			38
6	3	1	1.00000			39
60	2		2.00000			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) 03/31/2017	Year/Period of Report End of 2016/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.
24	1		1.00000			1
11	6		1.00000			2
37	3		2.00000			3
16	1		1.00000			4
16	1		1.00000			5
14	2		2.00000			6
25	2		2.00000			7
50	4		2.00000			8
76	3		1.00000			9
45	1		1.00000			10
90	2		2.00000			11
30	3	1	1.00000			12
39	4	1	2.00000			13
11	1		1.00000			14
45	1		1.00000			15
25	2		2.00000			16
13	1		1.00000			17
41	2		2.00000			18
19	3	1	1.00000			19
16	1		1.00000			20
21	3	1	1.00000			21
32	2		2.00000			22
13	1		1.00000			23
13	1		1.00000			24
61	2		2.00000			25
90	3	1	1.00000			26
11	3	1	1.00000			27
135	3		3.00000			28
29	2		2.00000			29
135	3		3.00000			30
16	1		1.00000			31
20	6	1	2.00000			32
19	3	1	1.00000			33
90	2		2.00000			34
45	1		1.00000			35
27	2		2.00000			36
19	3		1.00000			37
61	2		2.00000			38
214	6	1	2.00000			39
59	3		3.00000			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) 03/31/2017	Year/Period of Report End of 2016/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)	
12	1		1.00000			1
21	6	1	2.00000			2
120	6	2	2.00000			3
180	3	1	1.00000			4
225	3		3.00000			5
42	3	1	1.00000			6
290	4	1	2.00000			7
20	3	1	1.00000			8
28	4		2.00000			9
90	3	1	1.00000			10
46	2		2.00000			11
45	1		1.00000			12
13	3	2	1.00000			13
58	10	3	2.00000			14
30	1		1.00000			15
43	2		2.00000			16
200	1		1.00000			17
588	4	2	2.00000			18
7	1		1.00000			19
29	6	1	2.00000			20
80	2		2.00000			21
400	2		2.00000			22
240	6	1	2.00000			23
75	2		2.00000			24
35	3		3.00000			25
7	1		1.00000			26
25	3	1	1.00000			27
90	2		2.00000			28
19	3	1	1.00000			29
16	3		1.00000			30
16	1		1.00000			31
60	2		2.00000			32
135	3		3.00000			33
135	3		3.00000			34
90	2		2.00000			35
75	2		2.00000			36
16	1		1.00000			37
400	2		2.00000			38
75	2		2.00000			39
14	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	03/31/2017	End of 2016/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.
43	2		2.00000			1
61	2		2.00000			2
60	2		2.00000			3
170	6	1	2.00000			4
11	3	1	1.00000			5
30	1		1.00000			6
135	3	1	3.00000			7
75	2		2.00000			8
11	1		1.00000			9
13	1		1.00000			10
105	3		3.00000			11
32	6	1	2.00000			12
68	3	1	1.00000			13
180	4		4.00000			14
25	2	1	2.00000			15
400	2		1.00000			16
16	1		1.00000			17
16	1		1.00000			18
8	1		1.00000			19
840	2		2.00000			20
135	3		3.00000			21
45	1		1.00000			22
90	2		2.00000			23
25	4		2.00000			24
90	2		2.00000			25
63	2		2.00000			26
45	1		1.00000			27
127	3		3.00000			28
32	2		2.00000			29
180	4		4.00000			30
23	2		2.00000			31
11	1		1.00000			32
13	1		1.00000			33
11	3	1	1.00000			34
13	1		1.00000			35
21	3	1	1.00000			36
80	3	1	1.00000			37
90	2	1	2.00000			38
13	1		1.00000			39
50	3		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	03/31/2017	End of 2016/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)	
60	2		2.00000			1
30	1		1.00000			2
60	2		2.00000			3
225	3		3.00000			4
30	1		1.00000			5
22	2		2.00000			6
25	3		1.00000			7
50	2		2.00000			8
11	1		1.00000			9
21	3	1	1.00000			10
60	2		2.00000			11
45	1		1.00000			12
19	3	1	1.00000			13
60	2		2.00000			14
105	3		3.00000			15
32	2		2.00000			16
25	4		2.00000			17
49	4	1	2.00000			18
600	2		2.00000			19
823	4	1	2.00000			20
60	2		2.00000			21
16	1		1.00000			22
25	1		1.00000			23
13	1		1.00000			24
16	1		1.00000			25
21	3	1	SVC	1	15	26
117	3	1	1.00000			27
120	3		1.00000			28
1122	3	1	2.00000			29
45	1		1.00000			30
19	3		1.00000			31
22	4		2.00000			32
19	3		1.00000			33
16	1		1.00000			34
255	4	1	2.00000			35
30	1		1.00000			36
32	2		2.00000			37
7	1		1.00000			38
80	3		1.00000			39
840	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.
16	1		1.00000			1
22	2		2.00000			2
27	2		2.00000			3
81	3		3.00000			4
90	2		2.00000			5
19	3	1	1.00000			6
38	3		1.00000			7
60	2		2.00000			8
32	2		2.00000			9
12	7	1	2.00000			10
60	2		2.00000			11
21	3		3.00000			12
50	5		3.00000			13
67	5		3.00000			14
16	1		1.00000			15
13	2		2.00000			16
12	1		1.00000			17
29	2		2.00000			18
60	2		2.00000			19
19	2		2.00000			20
16	3		1.00000			21
134	3		1.00000			22
308	4		2.00000			23
180	3	1	1.00000			24
28	4		2.00000			25
50	3	1	1.00000			26
13	1		1.00000			27
1260	3		sync cond	2	80	28
150	2		2.00000			29
90	2		2.00000			30
77	3		3.00000			31
60	2		2.00000			32
90	2		2.00000			33
70	2		2.00000			34
25	1		1.00000			35
16	1		1.00000			36
40	1		1.00000			37
13	3	1	1.00000			38
90	2		2.00000			39
16	1		1.00000			40

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
133	6		2.00000			1
77	3		2.00000			2
11	1		1.00000			3
4	1		1.00000			4
4	1		1.00000			5
400	2		SVC	1	50	6
20	3		1.00000			7
400	2		2.00000			8
823	4	1	2.00000			9
46	2		2.00000			10
16	1		1.00000			11
13	1		1.00000			12
16	1		1.00000			13
29	2		2.00000			14
90	2		2.00000			15
39	2		2.00000			16
105	3		3.00000			17
400	2		2.00000			18
22	1		1.00000			19
26	2		1.00000			20
76	3		1.00000			21
30	1		1.00000			22
60	2		2.00000			23
135	3		3.00000			24
90	2		2.00000			25
400	2		2.00000			26
1260	3		3.00000			27
11	3	1	1.00000			28
11	3		1.00000			29
47	3		3.00000			30
90	3	1	1.00000			31
90	2		2.00000			32
135	3		3.00000			33
23	2		2.00000			34
50	4		1.00000			35
400	2		2.00000			36
840	2		2.00000			37
75	2		2.00000			38
215	4		4.00000			39
25	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) 03/31/2017	Year/Period of Report End of 2016/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
90	2		2.00000			1
75	2		2.00000			2
76	3		3.00000			3
30	1		1.00000			4
90	3		1.00000			5
165	3		3.00000			6
14	2		2.00000			7
145	5	1	3.00000			8
19	3		1.00000			9
75	2		2.00000			10
90	2		2.00000			11
91	3		3.00000			12
19	3		1.00000			13
27	2		2.00000			14
25	6		2.00000			15
45	1		1.00000			16
11	3		1.00000			17
100	3		3.00000			18
400	2		2.00000			19
30	1	1	1.00000			20
90	2		2.00000			21
46	2		2.00000			22
21	3	1	1.00000			23
5	3	1	1.00000			24
45	1		1.00000			25
45	1		1.00000			26
51	3		3.00000			27
334	4		2.00000			28
840	3	1	1.00000			29
13	3	1	1.00000			30
840	2		2.00000			31
32	2		2.00000			32
13	3	1	1.00000			33
43	2		2.00000			34
21	3	1	1.00000			35
5	3	1	1.00000			36
29	2		2.00000			37
19	3		1.00000			38
45	1		1.00000			39
71	7		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)	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)	
30	1		1.00000			1
21	2		2.00000			2
45	1		1.00000			3
45	1		1.00000			4
105	3		3.00000			5
135	3		3.00000			6
31	3	1	1.00000			7
135	8	1	4.00000			8
11	3		1.00000			9
32	2		2.00000			10
13	3	1	1.00000			11
49	4	1	2.00000			12
43	4	1	2.00000			13
11	3	1	1.00000			14
1243	5	1	Sync Cond	2	80	15
90	2		2.00000			16
21	2		2.00000			17
32	2		2.00000			18
105	3		3.00000			19
13	4	1	1.00000			20
45	1		1.00000			21
170	3		3.00000			22
280	4	1	2.00000			23
5	3	1	1.00000			24
90	3	1	1.00000			25
30	1		1.00000			26
32	2		2.00000			27
13	2		2.00000			28
50	3		1.00000			29
45	1		1.00000			30
45	1		1.00000			31
21	3	1	1.00000			32
840	2		2.00000			33
45	1		1.00000			34
3366	9	2	2.00000			35
1630	10	1	4.00000			36
11	1		1.00000			37
34	4	1	2.00000			38
1260	3		3.00000			39
3364	9	2	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)	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
90	3		1.00000			2
60	2		2.00000			3
6	3	1	1.00000			4
90	2		2.00000			5
75	2		2.00000			6
11	1		1.00000			7
14	3	1	1.00000			8
43	2		2.00000			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
1243	5	1	3.00000			18
45	1		1.00000			19
120	3		3.00000			20
30	1		1.00000			21
269	3	1	1.00000			22
16	1		1.00000			23
105	3		3.00000			24
1680	4		2.00000			25
1122	3	1	1.00000			26
115	3		2.00000			27
135	3		2.00000			28
16	1		1.00000			29
79	5		3.00000			30
30	1		1.00000			31
200	4	1	1.00000			32
150	2		2.00000			33
1646	8	1	SVC	1	200	34
80	3		1.00000			35
90	2		2.00000			36
20	4	1	2.00000			37
29	2		2.00000			38
41	4		2.00000			39
16	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) 03/31/2017	Year/Period of Report End of 2016/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.
32	2		2.00000			1
90	2		1.00000			2
45	1		1.00000			3
90	2		2.00000			4
30	6		2.00000			5
45	1		1.00000			6
23	2		2.00000			7
43	3		2.00000			8
210	4		4.00000			9
175	4		4.00000			10
120	3		3.00000			11
38	3	1	1.00000			12
135	3		3.00000			13
90	3		3.00000			14
75	2		2.00000			15
42	6	1	2.00000			16
31	4		2.00000			17
16	1		1.00000			18
45	1		1.00000			19
18	4		2.00000			20
60	2		2.00000			21
16	1		1.00000			22
6	3		1.00000			23
25	7		2.00000			24
11	1		1.00000			25
60	3		1.00000			26
22	3		1.00000			27
45	1		1.00000			28
41	2		2.00000			29
25	2		2.00000			30
5	3	1	1.00000			31
16	1		1.00000			32
23	2		2.00000			33
168	3	1	1.00000			34
420	1		1.00000			35
11	1		1.00000			36
45	1		1.00000			37
840	2		2.00000			38
30	1		1.00000			39
30	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/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.
45	1		1.00000			1
45	1		1.00000			2
30	1		1.00000			3
45	1		1.00000			4
90	3		3.00000			5
135	3		3.00000			6
195	3		3.00000			7
14	6	1	2.00000			8
80	3	1	1.00000			9
50	2		2.00000			10
13	1		1.00000			11
61	2		2.00000			12
58	4		2.00000			13
57	5	1	3.00000			14
45	1		1.00000			15
22	4		2.00000			16
135	3		3.00000			17
840	2		2.00000			18
95	3		1.00000			19
41	4	1	2.00000			20
30	1		1.00000			21
30	1		1.00000			22
39	2		2.00000			23
135	3		3.00000			24
45	1		1.00000			25
13	1		1.00000			26
11	1		1.00000			27
16	1		1.00000			28
65	2		1.00000			29
32	2		2.00000			30
45	1		StatCom	2	8	31
45	1		1.00000			32
11	1		1.00000			33
32	2		2.00000			34
16	1		1.00000			35
25	6		2.00000			36
30	1		1.00000			37
16	4		2.00000			38
16	1		1.00000			39
823	4	1	2.00000			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) 03/31/2017	Year/Period of Report End of 2016/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.
19	3		1.00000			1
50	5		3.00000			2
23	3		2.00000			3
70	5		3.00000			4
14	3		2.00000			5
190	4	1	2.00000			6
30	1		1.00000			7
30	1		1.00000			8
90	2		2.00000			9
45	1		1.00000			10
11	1		1.00000			11
14	2		2.00000			12
90	2		2.00000			13
32	2		2.00000			14
64	4		2.00000			15
11	3		1.00000			16
254	6		2.00000			17
73	2		2.00000			18
11	3	1	1.00000			19
90	2		2.00000			20
73	4	1	2.00000			21
23	1		1.00000			22
27	4	1	2.00000			23
30	1		1.00000			24
90	2		2.00000			25
16	1		1.00000			26
1122	3	1	1.00000			27
200	2		1.00000			28
400	2		2.00000			29
90	2		2.00000			30
11	3	1	1.00000			31
11	3	1	1.00000			32
30	1		1.00000			33
19	3		1.00000			34
29	2		2.00000			35
12	3	1	1.00000			36
420	1		1.00000			37
186	3		3.00000			38
100	1		1.00000			39
823	4	1	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	03/31/2017	End of 2016/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)	
180	4		4.00000			1
98	2		2.00000			2
375	5		5.00000			3
450	6		6.00000			4
345	3		3.00000			5
18	2		2.00000			6
40	2		3.00000			7
30	1		1.00000			8
180	4		2.00000			9
160	4		4.00000			10
200	1		1.00000			11
135	3		3.00000			12
1260	3		Sync Cond	2	88	13
156	4		2.00000			14
45	1		1.00000			15
9	3	1	1.00000			16
16	1		1.00000			17
45	1		1.00000			18
120	3		3.00000			19
90	3	1	1.00000			20
300	4		4.00000			21
30	3	1	1.00000			22
60	2		2.00000			23
90	2		2.00000			24
27	2		2.00000			25
12	3		1.00000			26
135	3		3.00000			27
41	2		2.00000			28
157	3		3.00000			29
21	3	1	1.00000			30
5	3	1	1.00000			31
90	3	1	1.00000			32
60	2		1.00000			33
90	3	1	1.00000			34
30	1		1.00000			35
13	1		1.00000			36
72	4	1	2.00000			37
11	1		1.00000			38
45	1		1.00000			39
61	2		2.00000			40

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
16	1		1.00000			1
15	3	1	1.00000			2
60	2		2.00000			3
32	2		2.00000			4
49	4		2.00000			5
19	6		2.00000			6
806	6	1	2.00000			7
30	1		1.00000			8
75	6		2.00000			9
11	1		1.00000			10
60	2		2.00000			11
25	3		3.00000			12
19	1		1.00000			13
13	3	1	2.00000			14
13	1		1.00000			15
25	2		2.00000			16
600	2		2.00000			17
150	2		2.00000			18
51	4	1	2.00000			19
105	3		2.00000			20
11	3	1	1.00000			21
225	3		3.00000			22
75	2		2.00000			23
105	3		3.00000			24
22	6		1.00000			25
17	2		2.00000			26
45	1		1.00000			27
90	2		2.00000			28
21	3	1	1.00000			29
120	3		3.00000			30
13	1		1.00000			31
135	3		3.00000			32
90	3		3.00000			33
1008	5	1	3.00000			34
1122	3	1	1.00000			35
162	4		2.00000			36
27	2		2.00000			37
13	1		1.00000			38
225	3		3.00000			39
49	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.
21	3	1	1.00000			1
175	1		1.00000			2
90	2		2.00000			3
806	6	1	2.00000			4
3366	9	2	3.00000			5
90	2		2.00000			6
150	2		2.00000			7
13	1		1.00000			8
106	4		4.00000			9
16	1		1.00000			10
90	2		2.00000			11
90	2		2.00000			12
90	3	1	1.00000			13
24	4	2	2.00000			14
400	2		2.00000			15
30	1		1.00000			16
61	2		2.00000			17
32	2		2.00000			18
19	6		2.00000			19
29	2		2.00000			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
6	3	1	1.00000			27
30	1		1.00000			28
334	4	1	2.00000			29
29	2		2.00000			30
17	6		2.00000			31
90	2		4.00000			32
30	1		1.00000			33
60	2		2.00000			34
90	2		2.00000			35
150	2	1	2.00000			36
21	3	1	1.00000			37
60	2		2.00000			38
20	3		1.00000			39
11	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) 03/31/2017	Year/Period of Report End of 2016/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)	
16	1		1.00000			1
8	1		1.00000			2
600	2		2.00000			3
50	2		2.00000			4
90	2		2.00000			5
30	1		1.00000			6
24	4		2.00000			7
135	3		3.00000			8
30	1		1.00000			9
105	3		3.00000			10
29	2		2.00000			11
105	3		3.00000			12
44	4	1	2.00000			13
60	3	1	1.00000			14
400	2		2.00000			15
19	3		1.00000			16
105	3		3.00000			17
27	2		2.00000			18
19	3	1	1.00000			19
13	3	1	1.00000			20
30	1		1.00000			21
11	3	1	1.00000			22
14	3	1	1.00000			23
689	4	1	2.00000			24
14	1		1.00000			25
120	3		3.00000			26
23	3		1.00000			27
135	3		3.00000			28
60	2		3.00000			29
135	3		3.00000			30
13	1		1.00000			31
120	3		3.00000			32
11	1		1.00000			33
27	2		2.00000			34
-56						35
95654	1804	161		12	561	36
64594	366	57		10	545	37
						38
696	343	56				39
						40

Schedule Page: 426 Line No.: 33 Column: e

2.4 and 7.2

Schedule Page: 426 Line No.: 39 Column: e

2.4 and 7.2

Schedule Page: 426.1 Line No.: 36 Column: e

2.4 and 7.2

Schedule Page: 426.2 Line No.: 29 Column: e

2.4 and 7.2

Schedule Page: 426.6 Line No.: 13 Column: e

2.4 and 7.2

Schedule Page: 426.7 Line No.: 14 Column: e

2.4 and 7.2

Schedule Page: 426.7 Line No.: 35 Column: e

2.4 & 7.2

Schedule Page: 426.8 Line No.: 39 Column: c

115 or 60

Schedule Page: 426.10 Line No.: 34 Column: k

200-221

Schedule Page: 426.11 Line No.: 19 Column: c

115x70

Schedule Page: 426.12 Line No.: 5 Column: e

2.4 and 7.2

Schedule Page: 426.12 Line No.: 23 Column: e

2.4 and 7.2

Schedule Page: 426.15 Line No.: 40 Column: e

2.4 and 7.2

Schedule Page: 426.17 Line No.: 35 Column: a

The original entries in column f were in two decimal places, which the FERC software rounds automatically to whole numbers. The entry here is an adjustment to present the correct total.

Schedule Page: 426.17 Line No.: 37 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 606 Distribution Substations. This represents a total of 698 physical transmission and distribution substations (92+606=698). 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 665 substations with distribution transformer banks. (606+59 = 665).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2		PG&E Corporation		
3	Corporate A&G Allocations		923, 426.4, 426.5	73,551,996
4	Total - Administrative & General Expenses			73,551,996
5				
6	Rent Expense	Eureka Energy Company	532.0	314,986
7				
8	Total Non-power Good/Srv. provided by Affiliates			73,866,982
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			844,665
23	Administration			257,039
24	Banking Services			65,286
25	Tax Services			46,394
26	Business Planning Services			59,871
27	CEO Support			208,488
28	Compliance & Ethics Support			5,692
29	Consulting Services			6,833
30	Corporate Relations Support			1,156,775
31	Corporate Sustainability Support			226,779
32	Employee Transfer Fees			1,776,284
33	Finance Application Support			210
34	Financial Forecasting and Analysis			181,891
35	Fleet Services			75,065
36	Human Resources Support			274,426
37	Information Technology			380,364
38	IT Capital Cost			93,680
39	Insurance Support			8,968
40	Interest Accrual			37,493
41	Internal Audit Services			6,874
42	Investor Relations Support			9,274
1	**Non-power Goods or Services Provided by Affiliated**			
2				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
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		PG&E Corporation	930.2	
22	Legal			115,264
23	Strategy Support			281,052
24	Permit Expense			822
25	Real Estate and Faculty			855,037
26	Risk and Audit			5,835
27	Security Support			353,512
28	Strategic Analysis Support			80,836
29				
30	Total - A&G Direct Charge to PG&E Corporation			7,414,709
31				
32				
33		FUELCO	930.2	
34	Legal			4,262
35	Accounting			22,089
36	CFO Support			5,813
37	Fuel Purchasing Support			464,743
38	Supply Chain Support			1,099
39				
40	Total - A&G Direct Charge to FUELCO			498,006
41				
42	Total Non-power Good/Srv provided for Affil.			7,912,715
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/31/2017	End of 2016/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
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				

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 (99.99%)
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 (99.98%)
Affiliate Headcount/Total Consolidated Headcount

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