THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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 2015/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/eforms/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/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.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 2015/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)* 02/24/2016

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 DINYAR MISTRY	03 Signature DINYAR MISTRY	04 Date Signed *(Mo, Da, Yr)* 02/24/2016
02 Title VICE PRESIDENT, CFO, AND CONTROLLER		

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	02/24/2016	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

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

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

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.

Dinyar Mistry, Vice President, Controller, and CFO
77 Beale Street, B11H
San Francisco, CA 94105

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

California - October 10, 1905

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

Not applicable.

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

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

State of California only.

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

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

CONTROL OVER RESPONDENT

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

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

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.
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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	PG&E Real Estate, LLC	Formed to conduct	100	2
10		real estate transactions,		
11		most likely related to		
12		purchase of property rights		
13		of San Bruno incident.		
14				
15	Merritt Community Capital Fund V, L.P.	Formed to construct and own	2.4	3
16		low-income housing.		
17				
18	Morro Bay Mutual Water Company	Formed to jointly hold	50	4
19		property rights in connection		
20		with the divestiture of the		
21		Morro Bay Power Plant.		
22				
23	Moss Landing Mutual Water Company	Formed to jointly hold	33	5
24		property rights in connection		
25		with the divestiture of the		
26		Moss Landing Power Plant.		
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	STARS Alliance, LLC	Formed to increase efficiency	25	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

12/11/2015 - PG&E Real Estate was dissolved.

Schedule Page: 103.1 Line No.: 15 Column: d

Members include: Bank of America, Bank of the West, Fannie Mae, Freddie Mac, Home Savings of America, Sanwa Bank of California, Union Bank of California, and Wells Fargo Bank.

Schedule Page: 103.1 Line No.: 18 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.: 23 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: 103.2 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	02/24/2016	End of 2015/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	Vice Chairman	Christopher P. Johns	795,967
2	President, Electric	Geisha J. Williams	634,183
3	Senior VP, Financial Services	Kent M. Harvey	626,233
4	President, Gas	Nickolas Stavropoulos	613,221
5	Senior VP, Power Generation and Chief Nuclear Officer	Ed Halpin	550,800
6	Senior VP and Chief Information Officer	Karen A. Austin	529,300
7	Senior VP, Human Resources	John R. Simon	451,781
8	Senior VP, Safety and Shared Services	Desmond Bell	409,750
9	Senior VP, Gas Operations	Jesus Soto, Jr.	405,517
10	Senior VP, External Affairs and Public Policy	Helen A. Burt	394,250
11	VP, Chief Financial Officer and Controller	Dinyar B.Mistry	381,433
12	Senior VP, Electric Transmission and Distribution	Gregory K. Kiraly	376,167
13	Senior VP and Chief Customer Officer	Loraine M. Giammona	364,583
14	Senior VP, Energy Policy and Procurement	Fong Wan	362,601
15	Senior VP, Regulatory Affairs	Steven Malnight	341,000
16	Senior VP and Chief Ethics and Compliance Officer	Julie M. Kane	274,127
17	Senior VP, Corporate Affairs	Greg S. Pruett	32,808
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Schedule Page: 104 Line No.: 1 Column: b

Mr. Johns transferred from President to Vice Chairman on August 17, 2015.

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

Ms. Williams transferred from EVP, Electric Operations to President, Electric on August 17, 2015.

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

Mr. Harvey's role as SVP, Financial Services ended on August 17, 2015.

Schedule Page: 104 Line No.: 4 Column: b

Mr. Stavropoulos transferred from EVP, Gas Operations to President, Gas on August 17, 2015.

Schedule Page: 104 Line No.: 7 Column: b

Mr. Simon's role as SVP, Human Resources ended on August 17, 2015, he transferred to PG&E Corporation in the role of Executive Vice President Corp. Services and Human Resources.

Schedule Page: 104 Line No.: 16 Column: b

Ms. Kane was hired May 18, 2015.

Schedule Page: 104 Line No.: 17 Column: b

Mr. Pruett's employment ended January 31, 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Lewis Chew ***	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Anthony F. Earley, Jr. ***	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	Fred J. Fowler	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
12		
13	Maryellen C. Herringer ***	c/o PG&E Corporation
14		77 Beale Street, 32nd Floor
15		San Francisco, CA 94105
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17	Richard C. Kelly	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
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21	Roger H. Kimmel	c/o PG&E Corporation
22		77 Beale Street, 32nd Floor
23		San Francisco, CA 94105
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25	Richard A. Meserve ***	c/o PG&E Corporation
26		77 Beale Street, 32nd Floor
27		San Francisco, CA 94105
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29	Forrest E. Miller ***	c/o PG&E Corporation
30		77 Beale Street, 32nd Floor
31		San Francisco, CA 94105
32		
33	Rosendo G. Parra	c/o PG&E Corporation
34		77 Beale Street, 32nd Floor
35		San Francisco, CA 94105
36		
37	Barbara L. Rambo ***	c/o PG&E Corporation
38		77 Beale Street, 32nd Floor
39		San Francisco, CA 94105
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41	Barry Lawson Williams ***	c/o PG&E Corporation
42		77 Beale Street, 32nd Floor
43		San Francisco, CA 94105
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45	Anne Shen Smith	c/o PG&E Corporation
46		77 Beale Street, 32nd Floor
47		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	02/24/2016	End of 2015/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	Nickolas Stavropoulos	c/o Pacific Gas and Electric Company
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Geisha J. Williams	c/o Pacific Gas and Electric Company
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
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9	Christopher P. Johns	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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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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	02/24/2016	End of 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary capital 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, 2015

1. Changes in and important additions to franchise rights:

On March 6, 2013, the City and County of San Francisco filed two separate actions against PG&E in Superior Court alleging breach of PG&E's franchise agreements. One action (Superior Court Case No.CGC-13-529309) alleges PG&E has underpaid franchise fees arising under the electric franchise and seeks damages and other relief. In June, 2015, this action was entirely dismissed, with prejudice. The second action (Superior Court Case No.CGC-13-529310) alleges that PG&E has failed to relocate its facilities without expense to the City and seeks damages and other relief. PG&E is currently defending the claims in this action. This lawsuit seeks the award of monetary damages, and we believe this action does not change PG&E's existing franchise rights. This second action remains pending.

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 30, 2015, the Crazy Horse Canyon Switching Station was released to operations. This project, located in Monterey County, constructed a new 115 kV switching station in a three bay, breaker-and-a-half (BAAH) configuration.

On February 21, 2015, the Mercy Springs Switching Station was released to operations. This project, located in Merced County, constructed a new three element breaker and a half (BAAH) 70 kV switching station. This project was built to facilitate the interconnection of a 20 MW (net output) solar power-based generation facility by Vega Solar, LLC, to Pacific Gas and Electric Company's Los Banos – Canal - Oro Loma 70 kV Line, in Merced County.

On February 28, 2015, the Quinto Switching Station was released to operations. This project, located in Merced County, constructed a new 2-bay, breaker and a half (BAAH)

230 kV Quinto Switching Station expandable for up to 4-bays. This project was built to facilitate the interconnection of a 110 MW solar generation by Solar Star California XIII, LLC, to Pacific Gas and Electric Company's Los Banos – Westley 230 kV Line.

On October 12, 2015, the Mustang Switching Station was released to operations. This project, located in Kings County, constructed a new 3 bay, breaker and a half (BAAH) 230 kV Mustang Switching Station expandable for up to 6-bays. This project was built to facilitate the interconnection of a 100 MW solar generation by RE Mustang to Pacific Gas and Electric Company's Gates - Gregg and Gates - McCall 230 kV Line.

On October 22, 2015, the Shepherd Substation was released to operations. This project, located in Fresno County, interconnects the new distribution substation with one 115/21 kV, 45 MVA distribution transformer, by looping Pacific Gas and Electric Company's Kerckhoff – Clovis – Sanger 115 kV No. 1 Line. The equipment was installed to provide the necessary capacity to serve new and existing customers, and improve service reliability and operating flexibility in the Fresno – Clovis area.

On October 30, 2015, the Leprino Switching Station was released to operations. This project, located in Kings County, constructed a new three bay breaker and a half (BAAH) 115 kV Leprino Switching Station expandable for up to 6-bays. This project was built to facilitate the interconnection of a 100 MW solar generation by Henrietta Solar to Pacific Gas and Electric Company's Henrietta – GWF 115 kV Line.

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:

For the quarter ended March 31, 2015, the Utility did not issue any debt.

On June, 12, 2015, the Utility issued $400 million of 10-year unsecured senior notes at a coupon of 3.50% and $100 million of 30-year unsecured senior notes at a coupon of 4.30%, due June 15, 2025 and March 15, 2045, respectively. The $100 million 30-year series was a re-opening of the 4.30% 30-year senior notes issued in November 2014. In a bond re-opening, all of the terms of the new issue are identical to that of the original issue including coupon, interest payment dates, maturity date, etc. The Senior Notes were authorized by the California Public Utilities Commission ("CPUC") Decision No. 12-04-015 and Decision No. 15-01-030.

For the quarter ended September 30, 2015, the Utility did not issue any long-term debt.

On November 5, 2015, the Utility issued $450 million of 30-year unsecured senior notes at a coupon of 4.25% and $200 million of 10-year unsecured senior notes at a coupon of 3.50%. The 10-year senior note offering was a re-opening of a previously issued senior notes tranche. The Senior Notes were authorized by the

California Public Utilities Commission ("CPUC") Decision No. 15-01-030.

Refer to Note 4, Debt, of the Notes to Financial Statements on page 123 of the FERC Form 1.

b) Bank Credit Facilities and Commercial Paper:

At December 31, 2015, the Utility had $33 million of letters of credit outstanding, $1.02 billion of commercial paper outstanding and no borrowings under the $3 billion revolving credit facility. The short-term borrowings are authorized by CPUC Decision No. 09-05-002.

Refer to Note 4, Debt, of the Notes to Financial Statements on page 123 of the FERC Form 1.

c) Surety Bonds and Financial Guarantees Backed by Insurance

From January 1st, 2015 to March 31st, 2015, $7,457,202 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of March 31st, 2015, there was a total of $46,821,842 in long-term surety bond obligations outstanding.

From April 1, 2015 to June 30, 2015, $3,454,792 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of June 30, 2015, there was a total of $50,276,634 in long-term surety bond obligations outstanding.

From July 1, 2015 to September 30, 2015, $210,000 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of September 30, 2015, there was a total of $49,287,176 in long-term surety bond obligations outstanding.

From October 1, 2015 to December 31, 2015, $5,002,132 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of December 31, 2015, there was a total of $54,131,355 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, 2015, 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:

As provided for in labor agreements with the International Brotherhood of Electrical Workers ("IBEW"), Local 1245, representing a majority of the Utility's employees in physical and clerical classifications; the Engineers and Scientists of California, (“ESC”), representing certain Utility employees in the technical and engineering classifications; and the Service Employees International Union (“SEIU”), representing certain Utility security officers at Diablo Canyon Nuclear Power Plant, the following general wage increases were granted effective January 1, 2015:

IBEW Clerical classifications	2.75%
IBEW Physical classifications	2.75%
ESC non-exempt and some exempt classifications	2.75%
ESC other exempt classifications	2.75%
SEIU classifications	2.75%

The full annual cost of the above general wage increase is approximately $36.0 million.

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, 2015, 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 respondent 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:

During the fourth quarter of 2015, four beneficial owners of at least 5 percent of PG&E Corporation common stock as of December 31, 2014 provided asset management services to PG&E Corporation, Pacific Gas and Electric Company (“Utility”), and related entities: BlackRock, Inc. ("BlackRock"), State Street Corporation and affiliates (“State Street”), T. Rowe Price Associates Inc. (“Price Associates”), and the Vanguard Group and affiliates (“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.

Each of these beneficial owners is expected to provide services during 2015 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, 2015 (including PG&E Corporation's and Pacific Gas and Electric Company's joint 2015 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:

Q1'15:

Directors

The following individual was elected as a Director of the Utility:
- Anne Shen Smith, Director

Officers

The following individual became an officer of the Utility:

- James M. Welsch, Site Vice President, Diablo Canyon Power Plant

The following individuals are no longer officers of the Utility:

- Greg S. Pruett, Senior Vice President, Corporate Affairs
- Edward T. Bedwell, Vice President, Government Relations
- Elisabeth S. Brinton, Vice President, Corporate Strategy
- Janet C. Loduca, Vice President, Safety, Health and Environment

The following individuals' titles changed:

- Barry S. Allen, Vice President, Nuclear Services (formerly Site Vice President, Diablo Canyon Power Plant)
- Barry D. Anderson, Vice President, Emergency Preparedness and Operations (formerly Vice President Emergency Preparedness and Response)
- Andrew K. Williams, Vice President, Safety, Health and Environment (formerly Vice President, Human Resources)

Major Security Holders

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

- Cede & Co., P.O. Box 20, Bowling Green Station, New York, NY 10004-9998, increased its share ownership from 9,409,341 shares as of December 31, 2014 to 9,417,012 shares as of March 31, 2015. (approximately 91 percent of the total preferred shares outstanding).
- John R. Vaughn and Shirley M. Vaughn TR UA Oct 18 93 John & Shirley Vaughn Living

Trust Box 1135, Groveland, CA 95321-1125, are no longer major holders.

- Harold R. Griffith & Karen A. Griffith & Harold Robert Griffith Jr Jt Ten 257 W Railroad Avenue, Cotati, CA 94931 became major holders with 6,700 shares of preferred stock.

Q2'15:

Officers

- John C. Higgins, Vice President, Gas Transmission and Distribution Operations
- Aaron J. Johnson, Vice President, Customer Energy Solutions
- Mary K. King, Vice President, Human Resources

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

- Kevin B. Knapp, Vice President, Gas T&D Operations

The following individual's title changed:

- Stephen J. Cairns, Vice President, Internal Audit (formerly Vice President, Internal Audit and Compliance)

Major Security Holders

Cede & Co., P.O. Box 20, Bowling Green Station, New York, NY 10004-9998, increased its share ownership from 9,417,012 shares as of March 31, 2015 to 9,431,092 shares as of June 30, 2015. (Approximately 91 percent of the total preferred shares outstanding).

Q3'15:

Directors

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

- Christopher P. Johns, Director

The following individuals became Directors of the Utility:

- Nickolas Stavropoulos, Director
- Geisha J. Williams, Director

Officers

The following individuals became officers of the Utility:

- Bernard A. Cowens, Vice President and Chief Information Security Officer
- Kathleen B. Kay, Vice President, Business Technology
- Robert S. Kenney, Vice President, CPUC Regulatory Relations

The following individuals are no longer officers of the Utility:

- Kent M. Harvey, Senior Vice President, Financial Services
- John R. Simon, Senior Vice President, Human Resources
- Ezra C. Garrett, Vice President, Community Relations and Chief Sustainability Officer

The following individuals' titles changed:

- Christopher P. Johns, Vice Chairman (formerly President)
- Nickolas Stavropoulos, President, Gas (formerly President, Gas Operations; formerly Executive Vice President, Gas Operations)
- Geisha J. Williams, President, Electric (formerly President, Electric Operations; formerly Executive Vice President, Electric Operations)
- Helen A. Burt, Senior Vice President, External Affairs and Public Policy (formerly Senior Vice President, Corporate Affairs)
- Edward D. Halpin, Senior Vice President, Power Generation and Chief Nuclear Officer (formerly Senior Vice President and Chief Nuclear Officer)
- Gregory K. Kiraly, Senior Vice President, Electric Transmission and Distribution (formerly Senior Vice President, Electric Distribution Operations)
- Jesus Soto, Jr., Senior Vice President, Gas Operations (formerly Senior Vice President, Engineering, Construction and Operations)
- Fong Wan, Senior Vice President, Energy Policy and Procurement (formerly Senior Vice President, Energy Procurement)
- Mallikarjun Angalakudati, Vice President, Gas Business and Performance Management (formerly Vice President, Financial and Resource Management, Gas Operations)
- William D. Arndt, Vice President, Electric Business and Performance Management (formerly Vice President, Strategic Business Management)
- Patrick M. Hogan, Vice President, Electric Strategy and Asset Management (formerly Vice President, Electric Operations, Asset Management)
- M. Kirk Johnson, Vice President, Gas Major Projects and Programs (formerly Vice President, Major Projects and Programs)
- Sumeet Singh, Vice President, Gas Asset and Risk Management (formerly Vice President, Asset and Risk Management)
- Rolando I. Trevino, Vice President, Gas Engineering and Design (formerly Vice President, Engineering and Design)

Major Security Holders

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

- Cede & Co., P.O. Box 20, Bowling Green Station, New York, NY 10004-9998, increased its share ownership from 9,431,092 shares as of June 30, 2015 to 9,448,412 shares as of September 30, 2015. (Approximately 92 percent of the total preferred shares outstanding).

Q4'15:

Officers

The following individuals are no longer officers of the Utility:

- Christopher P. Johns, Vice Chairman
- Barry S. Allen, Vice President, Nuclear Services
- Jason P. Wells, Vice President, Business Finance

Major Security Holders

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

- Cede & Co., P.O. Box 20, Bowling Green Station, New York, NY 10004-9998, increased its share ownership from 9,448,412 shares as of September 30, 2015 to 9,459,515 shares as of December 31, 2015. (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	02/24/2016	End of 2015/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	71,575,321,308	67,222,420,967
3	Construction Work in Progress (107)	200-201	2,057,204,814	2,218,869,812
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		73,632,526,122	69,441,290,779
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	32,001,238,924	30,184,989,921
6	Net Utility Plant (Enter Total of line 4 less 5)		41,631,287,198	39,256,300,858
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	285,001,087	246,107,680
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		387,399,860	389,415,071
10	Spent Nuclear Fuel (120.4)		2,067,748,581	1,970,583,455
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,256,442,841	2,133,540,139
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		483,706,687	472,566,067
14	Net Utility Plant (Enter Total of lines 6 and 13)		42,114,993,885	39,728,866,925
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)		20,327,286	20,059,172
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	40,152,618	39,484,076
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	234,129,712	39,492,939
24	Other Investments (124)		93,856	103,114
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,469,600,241	2,421,136,556
29	Special Funds (Non Major Only) (129)		344,229,090	367,968,507
30	Long-Term Portion of Derivative Assets (175)		169,617,807	165,180,013
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,278,150,610	3,053,424,377
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		56,893,820	52,731,103
36	Special Deposits (132-134)		234,311,946	297,788,840
37	Working Fund (135)		142,105	133,330
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,213,643,677	1,080,576,845
41	Other Accounts Receivable (143)		720,951,032	672,302,430
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		53,937,877	65,745,325
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		24,730,333	22,986,639
45	Fuel Stock (151)	227	1,004,654	1,335,700
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	312,558,926	304,439,339
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	266,941,383	120,516,764

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		234,129,712	39,492,939
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		125,316,011	170,893,044
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		138,886,943	152,257,202
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)		855,009,217	776,053,564
62	Miscellaneous Current and Accrued Assets (174)		85,414,486	101,342,945
63	Derivative Instrument Assets (175)		263,442,551	233,818,805
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		169,617,807	165,180,013
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)		3,841,561,688	3,716,758,273
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		117,777,872	114,014,521
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	8,666,911,679	7,687,225,400
73	Prelim. Survey and Investigation Charges (Electric) (183)		30,101	70,648
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)		16,859	40
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	48,854,341	44,141,845
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)		115,842,466	136,070,228
82	Accumulated Deferred Income Taxes (190)	234	2,084,286,484	1,905,341,596
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		11,033,719,802	9,886,864,278
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		60,324,333,310	56,441,821,178

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	1,321,874,045	1,321,874,045
3	Preferred Stock Issued (204)	250-251	257,994,575	257,994,575
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,805,194,230	1,805,194,230
7	Other Paid-In Capital (208-211)	253	5,445,547,927	4,745,022,882
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	8,312,192,120	8,179,336,707
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-50,038,177	-49,284,486
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)	3,223,118	4,743,591
16	Total Proprietary Capital (lines 2 through 15)		17,060,119,053	16,229,012,759
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	16,099,970,000	14,949,970,000
19	(Less) Reaquired Bonds (222)	256-257	207,870,000	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)		18,739,361	17,751,896
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		70,661,348	59,465,071
24	Total Long-Term Debt (lines 18 through 23)		15,840,178,013	14,700,386,825
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		48,764,750	68,999,073
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		475,306,520	493,726,984
29	Accumulated Provision for Pensions and Benefits (228.3)		2,534,259,377	2,476,525,534
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,034,861,135	939,268,830
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		117,403,844	117,488,245
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		3,643,081,915	3,575,482,515
35	Total Other Noncurrent Liabilities (lines 26 through 34)		7,853,677,541	7,671,491,181
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		1,019,197,000	633,000,000
38	Accounts Payable (232)		2,264,738,341	2,100,146,770
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		21,561,694	21,747,099
41	Customer Deposits (235)		237,243,313	235,923,353
42	Taxes Accrued (236)	262-263	32,425,983	-111,110,991
43	Interest Accrued (237)		210,157,281	203,587,055
44	Dividends Declared (238)		2,319,386	2,319,386
45	Matured Long-Term Debt (239)		0	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	02/24/2016	end of 2015/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		34,402,580	31,286,285
48	Miscellaneous Current and Accrued Liabilities (242)		496,542,387	784,402,796
49	Obligations Under Capital Leases-Current (243)		20,234,323	21,189,721
50	Derivative Instrument Liabilities (244)		171,082,998	165,184,131
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		117,403,844	117,488,245
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)		4,392,501,442	3,970,187,360
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		437,726,305	402,549,232
57	Accumulated Deferred Investment Tax Credits (255)	266-267	130,954,831	122,263,590
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	230,422,155	212,921,893
60	Other Regulatory Liabilities (254)	278	2,606,485,396	2,244,891,189
61	Unamortized Gain on Reaquired Debt (257)		1,155,069	1,301,535
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	307	307
63	Accum. Deferred Income Taxes-Other Property (282)		11,466,564,653	10,506,974,100
64	Accum. Deferred Income Taxes-Other (283)		304,548,545	379,841,207
65	Total Deferred Credits (lines 56 through 64)		15,177,857,261	13,870,743,053
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		60,324,333,310	56,441,821,178

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	17,009,666,384	17,283,736,125		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	9,886,586,673	10,441,056,783		
5	Maintenance Expenses (402)	320-323	1,403,571,300	1,174,740,248		
6	Depreciation Expense (403)	336-337	2,216,270,523	2,083,040,148		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	329,686,099	289,115,256		
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)		63,581,018	58,796,615		
13	(Less) Regulatory Credits (407.4)			28,338		
14	Taxes Other Than Income Taxes (408.1)	262-263	497,102,693	474,722,162		
15	Income Taxes - Federal (409.1)	262-263	-101,114,397	230,858,410		
16	- Other (409.1)	262-263	94,731,839	-14,195,918		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,549,010,567	366,942,456		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,155,700,268	73,716,826		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		661,421	745,781		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		28	98		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		14,783,064,598	15,030,585,117		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,226,601,786	2,253,151,008		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
13,695,879,713	13,735,510,811	3,313,786,671	3,548,225,314			2
						3
7,870,377,304	8,290,479,561	2,016,209,369	2,150,577,222			4
914,929,161	744,963,506	488,642,139	429,776,742			5
1,728,219,651	1,626,512,435	488,050,872	456,527,713			6
						7
230,390,325	210,691,416	99,295,774	78,423,840			8
						9
						10
						11
63,581,018	58,796,615					12
	28,338					13
387,952,658	373,661,822	109,150,035	101,060,340			14
-43,668,897	164,936,680	-57,445,500	65,921,730			15
197,854,696	16,852,958	-103,122,857	-31,048,876			16
893,509,255	359,856,850	655,501,312	7,085,606			17
537,167,850	30,819,196	618,532,418	42,897,630			18
						19
661,421	745,781					20
						21
28	98					22
						23
						24
11,705,315,872	11,815,158,430	3,077,748,726	3,215,426,687			25
1,990,563,841	1,920,352,381	236,037,945	332,798,627			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	02/24/2016	End of 2015/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)		2,226,601,786	2,253,151,008		
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	1,191,524	926,903		
37	Interest and Dividend Income (419)		7,930,273	7,884,768		
38	Allowance for Other Funds Used During Construction (419.1)		106,606,132	99,830,137		
39	Miscellaneous Nonoperating Income (421)		29,518,108	46,607,498		
40	Gain on Disposition of Property (421.1)		248,785	6,686,138		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		145,494,822	161,935,444		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		132,582	2,628,258		
45	Donations (426.1)		11,816,629	10,624,263		
46	Life Insurance (426.2)					
47	Penalties (426.3)		496,839,806	15,260,028		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		12,178,696	13,074,272		
49	Other Deductions (426.5)		631,207,567	345,881,272		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,152,175,280	387,468,093		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	344,953	332,125		
53	Income Taxes-Federal (409.2)	262-263	65,328	877,003		
54	Income Taxes-Other (409.2)	262-263	-58,761,109	-28,535,636		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	33,291,946	25,484,605		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	376,247,024	117,707,398		
57	Investment Tax Credit Adj.-Net (411.5)		-3,934,593	-3,621,084		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-405,240,499	-123,170,385		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-601,439,959	-102,362,264		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		726,652,517	678,973,384		
63	Amort. of Debt Disc. and Expense (428)		31,795,041	31,692,181		
64	Amortization of Loss on Reaquired Debt (428.1)		22,038,555	22,265,238		
65	(Less) Amort. of Premium on Debt-Credit (429)		1,728,535	1,412,482		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		146,465	146,964		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		32,455,716	31,178,361		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		47,923,080	44,838,168		
70	Net Interest Charges (Total of lines 62 thru 69)		763,143,749	717,711,550		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		862,018,078	1,433,077,194		
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)		862,018,078	1,433,077,194		

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

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

	2015		2014	
	Revenues	Expenses	Revenues	Expenses
Electric	42,247,495	61,577,902	40,815,362	60,674,916
Gas	143,846,937	124,516,530	133,733,760	113,874,206
Total	186,094,432	186,094,432	174,549,122	174,549,122

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

Refer to the footnote for Line 2, column c.

Schedule Page: 114 Line No.: 47 Column: c

Includes a one-time $400 million bill credit refundable to the Utility's natural gas customers and $100 million fines paid. (In August 2015, the Utility paid a $300 million fine to the State General Fund. Of the $300 million paid, $100 million was accrued in 2015 and $200 was accrued in 2014). These charges were imposed by the Penalty Decision approved by the CPUC on April 9, 2015 in connection with the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. For additional information, see Enforcement and Litigation Matters of Note 13 in the Notes to Financial Statements page 122-123.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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		7,981,987,690	7,294,656,049
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		860,826,554	1,432,150,291
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	-19,147,365	(16,582,323)
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-19,147,365	(16,582,323)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25	Preferred Dividends		-13,916,356	(13,916,358)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-13,916,356	(13,916,358)
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33	Common Stock Dividends		-716,000,000	(716,000,000)
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-716,000,000	(716,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,945,215	1,680,031
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		8,095,695,738	7,981,987,690
	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	02/24/2016	End of 2015/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)		19,147,365	16,582,323
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		19,147,365	16,582,323
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		197,349,017	180,766,694
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		216,496,382	197,349,017
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		8,312,192,120	8,179,336,707
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-49,284,486	(48,531,358)
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,191,524	926,903
51	(Less) Dividends Received (Debit)			
52	Other Adjustments (offset to 216)		-1,945,215	(1,680,031)
53	Balance-End of Year (Total lines 49 thru 52)		-50,038,177	(49,284,486)

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, 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.: 25 Column: d

The following is the detail of dividends declared on First Preferred Stocks for the year ended December 31, 2014:

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	2,222,719
5.00% Cumulative, Redeemable - Series A	934,322	1.250	1,167,908
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			$13,916,358

Schedule Page: 118 Line No.: 33 Column: c

This represents dividends declared on Common Stock to PG&E Corporation for the year ended December 31, 2015.

Schedule Page: 118 Line No.: 33 Column: d

This represents dividends declared on Common Stock to PG&E Corporation for the year ended December 31, 2014.

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

This represents utility subsidiary earnings reflected in operations and maintenance accounts for the year ended December 31, 2015.

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

This represents utility subsidiary earnings reflected in operations and maintenance accounts for the year ended December 31, 2014.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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)	862,018,078	1,433,077,194
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	2,545,956,622	2,372,155,404
5	Amortization of		
6	Unamortized Loss or Gain on Reacquired Debt	23,886,143	22,265,238
7	Expenses, Discount and Premium - Long Term Debt	17,008,272	16,906,279
8	Deferred Income Taxes (Net)	717,978,836	744,247,788
9	Investment Tax Credit Adjustment (Net)	-3,934,593	-3,621,084
10	Net (Increase) Decrease in Receivables	-316,860,645	710,970,470
11	Net (Increase) Decrease in Inventory	37,788,491	-22,959,462
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	166,781,286	-165,740,303
14	Net (Increase) Decrease in Other Regulatory Assets	-874,286,262	-1,843,472,589
15	Net Increase (Decrease) in Other Regulatory Liabilities	572,472,642	266,582,649
16	(Less) Allowance for Other Funds Used During Construction	106,606,132	99,830,137
17	(Less) Undistributed Earnings from Subsidiary Companies	668,542	1,019,354
18	Other (provide details in footnote):	53,944,503	160,912,940
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	3,695,478,699	3,590,475,033
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-5,189,879,527	-4,821,915,622
27	Gross Additions to Nuclear Fuel	-88,383,294	-110,379,731
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-106,606,132	-99,830,137
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-5,171,656,689	-4,832,465,216
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	21,512,892	28,956,886
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	2,585,938	5,606,928
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Net (Increase) Decrease in Restricted Cash	63,476,894	3,017,734
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	1,269,082,230	1,335,997,895
55	Purchases of nuclear decommissioning trust investments and Other	-1,392,384,267	-1,333,106,306
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-5,207,383,002	-4,791,992,079
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,122,764,475	1,961,040,567
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	382,934,742	-282,574,474
67	Other (provide details in footnote):		
68	Equity contribution from PG&E Corporation	705,000,000	705,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	2,210,699,217	2,383,466,093
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-538,559,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Customer Advances for Construction	35,177,073	68,797,961
78	Net Decrease in Short-Term Debt (c)		
79	Other	115,861	8,596,154
80	Dividends on Preferred Stock	-13,916,356	-13,916,358
81	Dividends on Common Stock	-716,000,000	-716,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	1,516,075,795	1,192,384,850
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	4,171,492	-9,132,196
87			
88	Cash and Cash Equivalents at Beginning of Period	52,864,433	61,996,629
89			
90	Cash and Cash Equivalents at End of period	57,035,925	52,864,433

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

This consists of the following:

	2015	2014
Disallowed Capital Expenditures	$ 407,495,789	$ 116,000,000
Decrease in Other Working Capital	(282,588,834)	(4,619,427)
Increase (Decrease) - Other Noncurrent Liabilities	(118,337,327)	(120,776,376)
Others		
Nuclear Fuel Lease Amortization	122,902,702	108,304,120
Payment on capital lease obligation	(21,189,720)	(23,011,865)
Collateral Posted	(18,603,931)	43,759,414
Bad Debt Expense	42,638,415	42,549,931
Tax benefit on stock option exercises*	(5,749,928)	(12,185,347)
Other-net	(72,622,663)	10,892,490
Total	$ 53,944,503	$ 160,912,940

* 2015 and 2014 tax benefit on stock option exercises are presented gross in accordance with applicable guidance. When book deductions exceed tax deductions, amounts are disclosed in operating activities. When tax deductions exceed book deductions, amounts are disclosed in financing activities.

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:

	2015	2014
Purchases of Nuclear Decommissioning Trust Investments	$1,392,393,525	$1,333,532,134
Decrease in other investments	(9,258)	(425,828)
Total	$1,392,384,267	$1,333,106,306

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:

	2015	2014
Increase (Decrease) in customer deposits	$ 1,319,962	$ 10,649,357
Debt Issuance Costs - ST Borrowings	(2,479,075)	(2,307,204)
Tax benefit on stock option exercises*	1,274,974	254,001
Total	$ 115,861	$ 8,596,154

* 2015 and 2014 tax benefit on stock option exercises are presented gross in accordance with applicable guidance. When book deductions exceed tax deductions, amounts are disclosed in operating activities. When tax deductions exceed book deductions, amounts are disclosed in financing activities.

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:

		2015		2014
Cash (131)	$	56,893,820	$	52,731,103
Working Funds (135)		142,105		133,330
Total	$	57,035,925	$	52,864,433

Supplemental disclosures of cash flow information (in millions):

		2015		2014
Cash paid for:				
Interest (net of amounts capitalized)	$	(675)	$	(618)
Income taxes paid (refunded), net		77		500
Supplemental disclosures of noncash investing and financing activities:				
Capital expenditures financed through accounts payable		440		339
Terminated capital leases		-		71

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

Refer to the footnote on Line 90, column B.

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, 2015, as filed with the Securities and Exchange Commission ("SEC") on February 18, 2016. 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, and exclude the impact of uncertain temporary tax positions, (3) cost of removal is reported in accumulated depreciation for FERC reporting purposes (GAAP requires that cost of removal be classified as a regulatory liability), (4) there is no current liability classification of the current portion of long-term debt for FERC reporting, (5) there is no reclassification of negative balances of balancing accounts from current assets to current liabilities for FERC reporting, (6) interdepartmental revenues and expenses between electric and gas operations of the Utility are not eliminated for FERC reporting, (7) penalties and disallowances are reported in other income deductions for FERC reporting, and (8) payments on capital lease obligations are disclosed in operating activities in the statement of cash flows.

Subsequent Events:

Management has evaluated the impact of events occurring after December 31, 2015 up to February 18, 2016, 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 February 24, 2016. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Energy Storage Assets (FERC Order No. 784):

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

Energy Plant Account

Energy storage assets totaled $32,814,644 at December 31, 2015, 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 $85,614 for the year ended December 31, 2015, 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 $1,000,995 for the year ended December 31, 2015, of which $176 is recorded in account 582 and $1,000,819 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 $317,143 for the year ended December 31, 2015, of which $7,093 is recorded in account 570 and $310,050 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 $79,709.

Energy storage-related payroll tax expenses are recorded in account 408.1 in the amount of $26,261.

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	$500,410	$267,148	$0	$85,614	$96,850
2	Hitachi	Distribution	San Jose, CA	$20,856,493	$500,585	$49,995	$0	$0	$9,120
3	Various	Distribution	Various	$672,145	$0	$0	$0	$0	$0
Totals				**$32,814,644**	**$1,000,995**	**$317,143**	**$0**	**$85,614**	**$105,970**

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 operating in 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. Actual results could differ materially from those estimates.

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 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

Restricted cash consists primarily 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:

(in millions, except estimated useful lives)	Estimated Useful Lives (years)	Balance at December 31, 2015	2014
Electricity generating facilities (1)	5 to 100	$ 9,860	$ 9,374
Electricity distribution facilities	15 to 55	28,476	26,633
Electricity transmission facilities	15 to 75	10,196	9,155
Natural gas distribution facilities	5 to 60	10,397	9,741
Natural gas transportation and storage facilities	5 to 65	6,352	5,937
Construction work in progress		2,059	2,220
Total property, plant, and equipment		**67,340**	**63,060**
Accumulated depreciation		(20,617)	(19,120)
Net property, plant, and equipment		**$ 46,723**	**$ 43,940**

(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 3.80% in 2015, 3.77% in 2014, and 3.51% in 2013. 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 $48 million and $107 million during 2015, $45 million and $100 million during 2014, and $47 million and $101 million during 2013.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2015 and 2014, including nuclear decommissioning obligations:

(in millions)	2015	2014
ARO liability at beginning of year	$ 3,575	$ 3,538
Revision in estimated cash flows	13	(16)
Accretion	169	163
Liabilities settled	(114)	(110)
ARO liability at end of year	**$ 3,643**	**$ 3,575**

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. 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 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 $2.5 billion at December 31, 2015 and 2014. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $3.5 billion at December 31, 2015 and 2014 (or $6.1 billion in future dollars). These estimates are based on the 2012 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. The Utility recorded charges of $407 million in 2015 for estimated capital spending that is probable of disallowance related to the Penalty Decision and $116 million and $196 million in 2014 and 2013, respectively, for PSEP capital costs that are expected to exceed the CPUC's authorized levels or that are specifically disallowed. (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, 2015, 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, 2015, 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 of the Notes to the Consolidated Financial Statements.

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, 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.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2014 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
Beginning balance	$ (7)	$ 15	$ 42	$ 50
Other comprehensive income before reclassifications:				
Change in investments (net of taxes of $0, $0, and $4, respectively)	-	-	5	5
Unrecognized net actuarial loss (net of taxes of $404, $19, and $0, respectively)	(588)	(28)	-	(616)
Unrecognized prior service cost (net of taxes of $0, $0, and $0, respectively)	1	-	-	1
Regulatory account transfer (net of taxes of $394, $19, and $0, respectively)	573	28	-	601
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (net of taxes of $8, $9, and $0, respectively) (1)	12	14	-	26
Amortization of net actuarial loss (net of taxes of $1, $1, and $0, respectively) (1)	1	1	-	2
Regulatory account transfer (net of taxes of $9, $10, and $0, respectively) (1)	(13)	(15)	-	(28)
Realized gain on investments (net of taxes of $0, $0, and $20, respectively)	-	-	(30)	(30)
Net current period other comprehensive loss	**(14)**	**-**	**(25)**	**(39)**

Ending balance	**$ (21)**	**$ 15**	**$ 17**	**$ 11**

(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.

New Accounting Pronouncements

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 guidance to help improve 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.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes*, which amends existing guidance on the presentation of deferred income tax assets and liabilities. The amendments in the ASU require that all deferred tax liabilities and assets be classified as noncurrent on the balance sheet. This ASU will be effective for PG&E Corporation and the Utility on January 1, 2017, with earlier adoption permitted. PG&E Corporation and the Utility have implemented this standard as of the year ended December 31, 2015 on a prospective basis and the prior periods have not been retrospectively adjusted.

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 removes the requirement to categorize within the fair value hierarchy all investments measured using net asset value per share as a practical expedient. The ASU became effective for PG&E Corporation and the Utility on January 1, 2016. This standard will be adopted for related disclosures in the first quarter of 2016 and will not have an impact on the consolidated financial statements.

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. The ASU became effective for PG&E Corporation and the Utility on January 1, 2016. PG&E Corporation and the Utility have determined that this ASU will not impact their consolidated financial statements and related disclosures and will adopt this standard starting in the first quarter of 2016.

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 existing presentation of debt issuance costs. *PG&E Corporation and the Utility currently disclose debt issuance costs in current assets – other and noncurrent assets – other.* The amendments in this ASU, that became *effective* for PG&E Corporation and the Utility *on January 1, 2016*, 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 will adopt this standard in the first quarter of 2016 and do not expect the reclassification to have a material impact on their consolidated financial statements.

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which amends existing revenue recognition guidance. *In August 2015, the FASB issued* ASU No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*, deferring the effective date of this amendment for PG&E Corporation and the Utility by one year to January 1, 2018, with early adoption permitted as of the original effective date of January 1, 2017. *PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.*

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

	Balance at December 31,		Recovery
(in millions)	**2015**	**2014**	**Period**
Pension benefits (1)	$ 2,414	$ 2,347	Indefinitely (4)
Deferred income taxes (1)	3,054	2,390	47 years
Utility retained generation (2)	411	456	10 years
Environmental compliance costs (1)	748	717	32 years
Price risk management (1)	138	127	10 years
Electromechanical meters (3)	-	70	-
Unamortized loss, net of gain, on reacquired debt (1)	94	113	11 years
Other	170	102	Various
Total long-term regulatory assets	**$ 7,029**	**$ 6,322**	

(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) Represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices. As of December 31, 2015, the remaining balance of $70 million is included in current regulatory assets on the Consolidated Balance Sheets.

(4) 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, regulatory assets for electromechanical meters, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Current Regulatory Liabilities

At December 31, 2015 and 2014, the Utility had current regulatory liabilities of $676 million and $261 million, respectively. At December 31, 2015, the current regulatory liabilities consisted primarily of a $400 million bill credit to the Utility's natural gas customers resulting from the Penalty Decision. (See Note 13 below.) Current regulatory liabilities are included within current liabilities-other in the Consolidated Balance Sheets.

Long -Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	**2015**	**2014**
Cost of removal obligations (1)	$ 4,605	$ 4,211
Recoveries in excess of AROs (2)	631	754
Public purpose programs (3)	600	701
Other	485	624
Total long-term regulatory liabilities	**$ 6,321**	**$ 6,290**

(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)	**2015**	**2014**
Electric distribution	$ 380	$ 344
Utility generation	122	261
Gas distribution	493	566
Energy procurement	262	608
Public purpose programs	155	109
Other	348	378
Total regulatory balancing accounts receivable	**$ 1,760**	**$ 2,266**

	Payable Balance at December 31,	
(in millions)	**2015**	**2014**
Energy procurement	$ 112	$ 188
Public purpose programs	244	154
Other	359	748

Total regulatory balancing accounts payable	**$ 715**	**$ 1,090**

The electric distribution, utility generation, and gas distribution balancing accounts track the collection of revenue requirements approved in the GRC. 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 and low income 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)	**2015**	**2014**
PG&E Corporation		
Senior notes, 2.40%, due 2019	350	350
Total PG&E Corporation long-term debt	**350**	**350**
Utility		
Senior notes:		
5.625% due 2017	700	700
8.25% due 2018	800	800
3.50% due 2020	800	800
4.25% due 2021	300	300
3.25% due 2021	250	250
2.45% due 2022	400	400
3.25% due 2023	375	375
3.85% due 2023	300	300
3.40% due 2024	350	350
3.75% due 2024	450	450
3.50% due 2025	600	-
6.05% due 2034	3,000	3,000
5.80% due 2037	950	950
6.35% due 2038	400	400
6.25% due 2039	550	550
5.40% due 2040	800	800
4.50% due 2041	250	250
4.45% due 2042	400	400
3.75% due 2042	350	350
4.60% due 2043	375	375
5.125% due 2043	500	500
4.75% due 2044	675	675
4.30% due 2045	600	500
4.25% due 2046	450	-
Unamortized discount, net of premium	(53)	(43)
Total senior notes, net of current portion	**14,572**	**13,432**
Pollution control bonds:		
Series 1996 C, E, F, 1997 B, variable rates (1), due 2026 (2)	614	614
Series 2004 A-D, 4.75%, due 2023 (3)	345	345

Series 2009 A-D, variable rates (1), due 2016 and 2026 (4)	309	309
Less: current portion	(160)	-
Total pollution control bonds	**1,108**	**1,268**
Total Utility long-term debt, net of current portion	**15,680**	**14,700**
Total consolidated long-term debt, net of current portion	**$ 16,030**	**$ 15,050**

(1) At December 31, 2015, interest rates on these bonds were 0.01%.

(2) 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.

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

(4) Each series of these bonds is supported by a separate direct-pay letter of credit. Series C and D letters of credit expire on December 3, 2016 to coincide with the maturity of the underlying bonds. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

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 sale 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.

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, 2015:

(in millions)	Termination Date	Credit Facility Limit		Letters of Credit Outstanding	Commercial Paper Outstanding	Facility Availability
PG&E Corporation	April 2020	$ 300	(1)	$ -	$ -	$ 300
Utility	April 2020	3,000	(2)	33	1,019	1,948
Total revolving credit facilities		**$ 3,300**		**$ 33**	**$ 1,019**	**$ 2,248**

(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, 2015, PG&E Corporation's average outstanding commercial paper balance was $64 million and the maximum outstanding balance during the year was $128 million. For 2015, the Utility's average outstanding commercial paper balance was $678 million and the maximum outstanding balance during the year was $1.5 billion. There were no bank borrowings for both PG&E Corporation and the Utility in 2015.

Revolving Credit Facilities

On April 27, 2015, PG&E Corporation and the Utility amended and restated their respective $300 million and $3.0 billion revolving credit facilities. The amendments and restatements extended the termination dates of the credit facilities from April 1, 2019 to April 27, 2020, reduced the amount of lender commitments to the letter of credit sublimits from $100 million to $50 million for PG&E Corporation's credit facility and from $1.0 billion to $500 million for the Utility's credit facility, and reduced the swingline commitment on the Utility's credit facility from $300 million to $75 million. 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 additional periods.

Borrowings under each amended and restated credit agreement (other than swing line 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 amended and restated credit agreement and between 0.8% and 1.275% under the Utility's amended and restated credit agreement. The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation's amended and restated credit agreement and between 0% and 0.275% under the Utility's amended and restated credit agreement. In addition, the facility fee under PG&E Corporation's and the Utility's amended and restated 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 and the Utility's commercial paper programs are used primarily to fund temporary financing needs. On July 2, 2015, the Utility increased the commercial paper program limit from $1.75 billion to $2.5 billion. 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 2015, the average yield on outstanding PG&E Corporation and Utility commercial paper was 0.38% and 0.42%, respectively.

Other Short-term Borrowings

On May 11, 2015, $300 million principal amount of the Utility's Floating Rate Senior Notes matured.

Repayment Schedule

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2015 are reflected in the table below:

(in millions, except interest rates)	2016	2017	2018	2019	2020	Thereafter	Total

PG&E Corporation							
Average fixed interest rate	-	-	-	2.40 %	-	-	2.40 %
Fixed rate obligations	$ -	$ -	$ -	$ 350	$ -	$ -	$ 350
Utility							
Average fixed interest rate	-	5.63 %	8.25 %	-	3.50 %	4.91 %	5.05 %
Fixed rate obligations	$ -	$ 700	$ 800	$ -	$ 800	$ 12,670	$ 14,970
Variable interest rate as of December 31, 2015	0.01 %	-	-	0.01 %	0.01 %	-	0.01 %
Variable rate obligations (1)	$ 160	$ -	$ -	$ 149	$ 614	$ -	$ 923
Total consolidated debt	**$ 160**	**$ 700**	**$ 800**	**$ 499**	**$ 1,414**	**$ 12,670**	**$ 16,243**

(1) These bonds, due in 2016 and 2026, are backed by separate letters of credit that expire on December 3, 2016, June 5, 2019, or December 1, 2020.

NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 492,025,443 shares of common stock outstanding at December 31, 2015. PG&E Corporation held all of the Utility’s outstanding common stock at December 31, 2015.

In February 2015, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $500 million. During 2015, PG&E Corporation sold 1.4 million shares under this agreement for cash proceeds of $74 million, net of commissions paid of $1 million.

In August 2015, PG&E Corporation sold 6.8 million shares of its common stock in an underwritten public offering for cash proceeds of $352 million, net of fees.

In addition, during 2015, PG&E Corporation sold 7.9 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 $354 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 2015, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of $0.455 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%. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on a weighted average over four years. PG&E Corporation and the Utility are in compliance with these restrictions. At December 31, 2015, the Utility had restricted net assets of $15.2 billion and was limited to $110 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. In May 2014, the 2006 LTIP was terminated and the 2014 LTIP became effective. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 15,674,803 shares were available for future awards at December 31, 2015.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2015, 2014, and 2013:

(in millions)	2015	2014	2013

Restricted stock units	$ 47	$ 42	$ 36
Performance shares	46	36	28
Total compensation expense (pre-tax)	**$ 93**	**$ 78**	**$ 64**
Total compensation expense (after-tax)	**$ 55**	**$ 47**	**$ 38**

The amount of share-based compensation costs capitalized during 2015, 2014, and 2013 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 in 2014 and 2015 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 2015, 2014, and 2013 was $53.30, $43.76, and $42.92, respectively. The total fair value of restricted stock units that vested during 2015, 2014, and 2013 was $57 million, $34 million, and $30 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. As of December 31, 2015, $45 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.48 years.

The following table summarizes restricted stock unit activity for 2015:

	Number of Restricted Stock Units	**Weighted Average Grant-Date Fair Value**
Nonvested at January 1	2,538,357	$ 43.39
Granted	820,834	$ 53.30
Vested	(1,304,150)	$ 43.51
Forfeited	(82,142)	$ 45.63
Nonvested at December 31	**1,972,899**	$ 47.33

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 PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period. 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. The weighted average grant-date fair value for performance shares granted during 2015, 2014, and 2013 was $68.27, $51.81, and $33.45 respectively. There was no tax benefit associated with performance shares during each of these periods. As of December 31, 2015, $36 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.45 years.

The following table summarizes activity for performance shares in 2015:

	Number of Performance Shares	**Weighted Average Grant-Date Fair Value**
Nonvested at January 1	1,693,939	$ 42.37
Granted	669,519	68.27
Vested	(421,262)	33.57

Forfeited (1)	(491,584)	35.56
Nonvested at December 31	**1,450,612**	$ 59.24

(1) Includes performance shares that expired with 50% value as a result of total shareholder return results.

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, 2015 and December 31, 2014, 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, 2015, 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, 2015, 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 2015, 2014, and 2013.

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 2015, 2014, and 2013.

	Year Ended December 31,		
(in millions, except per share amounts)	**2015**	**2014**	**2013**
Income available for common shareholders	$ 874	$ 1,436	$ 814
Weighted average common shares outstanding, basic	484	468	444
Add incremental shares from assumed conversions:			
Employee share-based compensation	3	2	1
Weighted average common share outstanding, diluted	487	470	445
Total earnings per common share, diluted	**$ 1.79**	**$ 3.06**	**$ 1.83**

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 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)	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Current:						
Federal	$ (89)	$ (84)	$ (218)	$ (88)	$ (84)	$ (222)
State	11	(41)	(26)	6	(29)	(23)
Deferred:						
Federal	131	396	552	136	426	604
State	(76)	78	(35)	(69)	75	(28)
Tax credits	(4)	(4)	(5)	(4)	(4)	(5)
Income tax provision	**$ (27)**	**$ 345**	**$ 268**	**$ (19)**	**$ 384**	**$ 326**

The following table describes net deferred income tax liabilities:

	PG&E Corporation		**Utility**	
	Year Ended December 31,			
(in millions)	**2015**	**2014**	**2015**	**2014**
Deferred income tax assets:				
Customer advances for construction	$ 69	$ 88	$ 69	$ 88
Environmental reserve	85	111	85	111
Compensation and benefits	219	244	145	173
Tax carryforwards	1,703	1,177	1,462	946
Greenhouse gas allowances	340	56	340	56
Other	44	74	61	100
Total deferred income tax assets	**$ 2,460**	**$ 1,750**	**$ 2,162**	**$ 1,474**
Deferred income tax liabilities:				
Regulatory balancing accounts	$ 691	$ 512	$ 691	$ 512
Property related basis differences	9,656	8,683	9,638	8,666
Income tax regulatory asset (1)	1,244	974	1,245	974

Other	75	88	75	86
Total deferred income tax liabilities	**$ 11,666**	**$ 10,257**	**$ 11,649**	**$ 10,238**
Total net deferred income tax liabilities	**$ 9,206**	**$ 8,507**	**$ 9,487**	**$ 8,764**
Classification of net deferred income tax liabilities:				
Included in current liabilities (assets)	$ -	$ (6)	$ -	$ (9)
Included in noncurrent liabilities	9,206	8,513	9,487	8,773
Total net deferred income tax liabilities	**$ 9,206**	**$ 8,507**	**$ 9,487**	**$ 8,764**

(1) 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 above.)

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,					
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
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)	(4.9)	1.4	(3.1)	(4.8)	1.6	(2.2)
Effect of regulatory treatment of fixed asset differences (2)	(33.6)	(15.0)	(4.2)	(33.7)	(14.7)	(3.8)
Tax credits	(1.3)	(0.7)	(0.4)	(1.3)	(0.7)	(0.4)
Benefit of loss carryback	(1.5)	(0.8)	(1.1)	(1.5)	(0.8)	(1.0)
Non deductible penalties (3)	4.3	0.3	0.8	4.3	0.3	0.7
Other, net	(1.1)	(0.8)	(2.2)	(0.2)	0.4	(0.9)
Effective tax rate	**(3.1) %**	**19.4 %**	**24.8 %**	**(2.2) %**	**21.1 %**	**27.4 %**

(1) Includes the effect of state flow-through ratemaking treatment. In 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 in 2015 and 2014 as authorized by the 2014 GRC decision. Amounts are impacted by the level of income before income taxes.

(3) Represents the effects of non-tax deductible fines and penalties associated with the Penalty Decision. (For more information about the Penalty Decision see Note 13 below.)

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			**Utility**		
(in millions)	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Balance at beginning of year	$ 713	$ 666	$ 581	$ 707	$ 660	$ 575
Additions for tax position taken during a prior year	40	7	12	40	7	12
Reductions for tax position taken during a prior year	(349)	(9)	(6)	(349)	(9)	(6)
Additions for tax position taken during the current year	64	61	79	64	61	79
Settlements	-	(12)	-	-	(12)	-
Balance at end of year	**$ 468**	**$ 713**	**$ 666**	**$ 462**	**$ 707**	**$ 660**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2015 for PG&E Corporation and the Utility was $50 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, 2015, it is reasonably possible that unrecognized tax benefits will decrease by approximately $60 million within the next 12 months.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2015, 2014, and 2013, these amounts were immaterial.

IRS settlements

PG&E Corporation participated in the Compliance Assurance Process in 2015, 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 tax returns have been accepted through 2014 except for a few matters, the most significant of which relates to deductible repair costs. In December 2015, PG&E Corporation reached an agreement with the IRS on deductible repair costs for the 2011 tax year, subject to approval by the Joint Committee on Taxation. Deductible repair costs will continue to be subject to examination by the IRS for subsequent years. The IRS is expected to issue guidance in 2016 that clarifies which repair costs are deductible for the natural gas transmission and distribution businesses. Tax years after 2004 remain subject to examination by the state of California.

Carryforwards

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

(in millions)	December 31, 2015	Expiration Year
Federal:		
Net operating loss carryforward	$ 4,856	2029 - 2035
Tax credit carryforward	110	2029 - 2035
Charitable contribution loss carryforward	178	2017 - 2020
State:		
Net operating loss carryforward	$ 80	2033 - 2034
Tax credit carryforward	59	Various
Charitable contribution loss carryforward	119	2019 - 2020

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, 2015 for these tax attributes. As of December 31, 2015, PG&E Corporation had approximately $29 million of federal net operating loss carryforwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

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 as long as the current ratemaking mechanism remains in place and 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, 2015 and 2014, respectively, the volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume	
Underlying Product	**Instruments**	**2015**	**2014**
Natural Gas (1) (MMBtus (2))	Forwards and Swaps	333,091,813	308,130,101
	Options	111,550,004	164,418,002
Electricity (Megawatt-hours)	Forwards and Swaps	3,663,512	5,346,787
	Congestion Revenue Rights (3)	216,383,389	224,124,341

(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, 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**

At December 31, 2014, 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	$ 73	$ (4)	$ 19	$ 88
Other noncurrent assets – other	178	(13)	-	165
Current liabilities – other	(78)	4	26	(48)
Noncurrent liabilities – other	(140)	13	9	(118)
Total commodity risk	**$ 33**	**$ -**	**$ 54**	**$ 87**

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

	Commodity Risk		
	For the year ended December 31,		
(in millions)	**2015**	**2014**	**2013**
Unrealized gain/(loss) - regulatory assets and liabilities (1)	$ (6)	$ 124	$ 238
Realized loss - cost of electricity (2)	(14)	(83)	(178)
Realized loss - cost of natural gas (2)	(10)	(8)	(22)
Total commodity risk	**$ (30)**	**$ 33**	**$ 38**

(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, 2015, 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)	**2015**	**2014**
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (2)	$ (47)
Related derivatives in an asset position	-	-
Collateral posting in the normal course of business related to these derivatives	-	44
Net position of derivative contracts/additional collateral posting requirements (1)	**$ (2)**	**$ (3)**

(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, price risk management instruments, and other investments 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 and other investments are held by PG&E Corporation and not the Utility):

	Fair Value Measurements At December 31, 2015				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Money market investments	$ 64	$ -	$ -	$ -	$ **64**
Nuclear decommissioning trusts					
Money market investments	36	-	-	-	**36**
Global equity securities	1,520	13	-	-	**1,533**
Fixed-income securities	694	521	-	-	**1,215**
Total nuclear decommissioning trusts (2)	**2,250**	**534**	**-**	**-**	**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					
Money market investments	7	-	-	-	**7**
Global equity securities	-	26	-	-	**26**
Fixed-income securities	-	132	-	-	**132**
Total long-term disability trust	**7**	**158**	**-**	**-**	**165**
Total assets	**$ 2,321**	**$ 829**	**$ 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.

	Fair Value Measurements At December 31, 2014				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Money market investments	$ 94	$ -	$ -	$ -	$ **94**
Nuclear decommissioning trusts					
Money market investments	17	-	-	-	**17**
Global equity securities	1,585	13	-	-	**1,598**
Fixed-income securities	741	389	-	-	**1,130**
Total nuclear decommissioning trusts (2)	**2,343**	**402**	**-**	**-**	**2,745**
Price risk management instruments (Note 9)					
Electricity	-	17	232	2	**251**
Gas	1	1	-	-	**2**
Total price risk management instruments	**1**	**18**	**232**	**2**	**253**
Rabbi trusts					
Fixed-income securities	-	42	-	-	**42**
Life insurance contracts	-	72	-	-	**72**
Total rabbi trusts	**-**	**114**	**-**	**-**	**114**
Long-term disability trust					
Money market investments	7	-	-	-	**7**
Global equity securities	-	25	-	-	**25**
Fixed-income securities	-	128	-	-	**128**
Total long-term disability trust	**7**	**153**	**-**	**-**	**160**
Other investments	**33**	**-**	**-**	**-**	**33**
Total assets	**$ 2,478**	**$ 687**	**$ 232**	**$ 2**	**$ 3,399**
Liabilities:					
Price risk management instruments (Note 9)					
Electricity	$ 47	$ 5	$ 163	$ (52)	$ **163**
Gas	-	3	-	-	**3**
Total liabilities	**$ 47**	**$ 8**	**$ 163**	**$ (52)**	**$ 166**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $324 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. Investments, primarily consisting of equity securities, that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days. 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 year ended December 31, 2015 and 2014.

Trust Assets

Nuclear decommissioning trust assets and other trust assets are composed primarily of equity securities and debt securities. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

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. Equity securities also include commingled funds that are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world. Investments in these funds are classified as Level 2 because price quotes are readily observable and available.

Debt 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.

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 Risk and Audit Officer of the Utility, 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, 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

(in millions)	Fair Value at At December 31, 2014		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$ 232	$ 63	Market approach	CRR auction prices	$ (15.97) - 8.17
Power purchase agreements	$ -	$ 100	Discounted cash flow	Forward prices	$ 16.04 - 56.21

(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, 2015 and 2014, respectively:

	Price Risk Management Instruments	
(in millions)	**2015**	**2014**
Asset (liability) balance as of January 1	**$ 69**	**$ (30)**
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	20	99
Asset (liability) balance as of December 31	**$ 89**	**$ 69**

(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, 2015 and 2014, 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, 2015 and 2014.

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,			
	2015		2014	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
Debt (Note 4)				
PG&E Corporation	$ 350	$ 354	$ 350	$ 352
Utility	14,918	16,422	13,778	15,851

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, 2015				
Nuclear decommissioning trusts				
Money market 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**
As of December 31, 2014				
Nuclear decommissioning trusts				
Money market investments	$ 17	$ -	$ -	$ 17
Global equity securities	520	1,087	(9)	1,598
Fixed-income securities	1,059	75	(4)	1,130
Total nuclear decommissioning trusts (1)	1,596	1,162	(13)	2,745
Other investments	5	28	-	33
Total	**$ 1,601**	**$ 1,190**	**$ (13)**	**$ 2,778**

(1) Represents amounts before deducting $314 million and $324 million at December 31, 2015 and 2014, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

(in millions)	As of December 31, 2015
Less than 1 year	$ 18
1–5 years	470
5–10 years	273
More than 10 years	454
Total maturities of debt securities	**$ 1,215**

The following table provides a summary of activity for the debt and equity securities:

(in millions)	2015	2014	2013
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 1,268	$ 1,336	$ 1,619
Gross realized gains on sales of securities held as available-for-sale	55	118	94
Gross realized losses on sales of securities held as available-for-sale	(37)	(12)	(13)

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 2015 and 2014:

Pension Plan

(in millions)	2015	2014
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 14,216**	**$ 12,527**
Actual return on plan assets	(176)	1,946
Company contributions	334	332
Benefits and expenses paid	(629)	(589)
Fair value of plan assets at end of year	**$ 13,745**	**$ 14,216**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 16,696**	**$ 14,077**
Service cost for benefits earned	479	383
Interest cost	673	695
Actuarial (gain) loss	(922)	2,131
Plan amendments	1	(1)
Transitional costs	1	-
Benefits and expenses paid	(629)	(589)
Benefit obligation at end of year (1)	**$ 16,299**	**$ 16,696**
Funded Status:		
Current liability	$ (6)	$ (6)
Noncurrent liability	(2,547)	(2,474)
Net liability at end of year	**$ (2,553)**	**$ (2,480)**

(1) PG&E Corporation's accumulated benefit obligation was $14.7 billion and $14.9 billion at December 31, 2015 and 2014, respectively.

Postretirement Benefits Other than Pensions

(in millions)	2015	2014
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,092**	**$ 1,892**
Actual return on plan assets	(26)	241
Company contributions	61	57
Plan participant contribution	68	63

Benefits and expenses paid	(160)	(161)
Fair value of plan assets at end of year	**$ 2,035**	**$ 2,092**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,811**	**$ 1,597**
Service cost for benefits earned	55	45
Interest cost	71	76
Actuarial (gain) loss	(98)	166
Transitional costs	1	-
Benefits and expenses paid	(146)	(140)
Federal subsidy on benefits paid	4	4
Plan participant contributions	68	63
Benefit obligation at end of year	**$ 1,766**	**$ 1,811**
Funded Status: (1)		
Noncurrent asset	$ 344	$ 368
Noncurrent liability	(75)	(87)
Net asset at end of year	**$ 269**	**$ 281**

(1) At December 31, 2015 and 2014, 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)	**2015**	**2014**	**2013**
Service cost	$ 479	$ 383	$ 468
Interest cost	673	695	627
Expected return on plan assets	(873)	(807)	(650)
Amortization of prior service cost	15	20	20
Amortization of net actuarial loss	10	2	111
Net periodic benefit cost	**304**	**293**	**576**
Less: transfer to regulatory account (1)	34	42	(238)
Total expense recognized	**$ 338**	**$ 335**	**$ 338**

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

Postretirement Benefits Other than Pensions

(in millions)	**2015**	**2014**	**2013**
Service cost	$ 55	$ 45	$ 53
Interest cost	71	76	74
Expected return on plan assets	(112)	(103)	(79)
Amortization of prior service cost	19	23	23
Amortization of net actuarial loss	4	2	6
Net periodic benefit cost	**$ 37**	**$ 43**	**$ 77**

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 2016 are as follows:

(in millions)	Pension Plan	PBOP Plans
Unrecognized prior service cost	$ 8	$ 15
Unrecognized net loss	24	4
Total	**$ 32**	**$ 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,		
	2015	2014	2013	2015	2014	2013
Discount rate	4.37 %	4.00 %	4.89 %	4.27 - 4.48 %	3.89 - 4.09 %	4.70 - 5.00 %
Rate of future compensation increases	4.00 %	4.00 %	4.00 %	-	-	-
Expected return on plan assets	6.10 %	6.20 %	6.50 %	3.20 - 6.60 %	3.30 - 6.70 %	3.50 - 6.70 %

The assumed health care cost trend rate as of December 31, 2015 was 7.2%, decreasing gradually to an ultimate trend rate in 2024 and beyond of approximately 4%. 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	$ 113	$ (114)
Effect on service and interest cost	9	(9)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.1% compares to a ten-year actual return of 7.8%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 688 Aa-grade non-callable bonds at December 31, 2015. 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, REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Target allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening future funded status volatility. Derivative instruments such as equity index futures are used to meet target equity exposure. In addition, derivative instruments such as equity index futures and U.S. treasury futures are used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also 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		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
Global equity	25 %	25 %	25 %	32 %	31 %	30 %
Absolute return	5 %	5 %	5 %	3 %	3 %	3 %
Real assets	10 %	10 %	10 %	7 %	8 %	8 %
Fixed income	60 %	60 %	60 %	58 %	58 %	59 %
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, 2015 and 2014.

	Fair Value Measurements At December 31,							
	2015				2014			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Pension Plan:								
Short-term investments	$ 247	$ 369	$ -	**$ 616**	$ 352	$ 311	$ -	**$ 663**
Global equity	903	2,243	-	**3,146**	918	2,311	-	**3,229**
Absolute return	-	-	660	**660**	-	-	577	**577**
Real assets	581	-	753	**1,334**	620	-	675	**1,295**
Fixed-income	1,841	5,516	640	**7,997**	2,068	5,718	638	**8,424**
Total	**$ 3,572**	**$ 8,128**	**$ 2,053**	**$ 13,753**	**$ 3,958**	**$ 8,340**	**$ 1,890**	**$ 14,188**
PBOP Plans:								
Short-term investments	$ 20	$ -	$ -	**$ 20**	$ 28	$ -	$ -	**$ 28**
Global equity	104	545	-	**649**	124	549	-	**673**
Absolute return	-	-	65	**65**	-	-	55	**55**
Real assets	69	-	77	**146**	72	-	49	**121**
Fixed-income	150	1,010	-	**1,160**	163	1,055	1	**1,219**
Total	**$ 343**	**$ 1,555**	**$ 142**	**$ 2,040**	**$ 387**	**$ 1,604**	**$ 105**	**$ 2,096**
Total plan assets at fair value				**$ 15,793**				**$ 16,284**

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $13 million and $24 million at December 31, 2015 and 2014, 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, equity-index futures, and commingled funds comprised of equity securities spread across multiple industries and regions of the world. 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. Commingled equity funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled equity funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled equity funds are categorized as Level 1 and Level 2 assets.

Absolute Return

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 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. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models, and valuation inputs that are unobservable and are considered Level 3 assets.

Fixed-Income

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments. Commingled funds are considered Level 2 assets. Corporate fixed-income also includes privately placed debt portfolios which are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and Treasury futures. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

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, 2015 and 2014.

Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2015 and 2014:

(in millions) **For the year ended December 31, 2015**	**Pension Plan** **Absolute Return**	**Fixed-Income**	**Real Assets**	**Total**
Balance at beginning of year	$ 577	$ 638	$ 675	**$ 1,890**
Actual return on plan assets:				
Relating to assets still held at the reporting date	(7)	9	63	**65**
Relating to assets sold during the period	-	1	-	**1**
Purchases, issuances, sales, and settlements:				
Purchases	90	2	17	**109**
Settlements	-	(10)	(2)	**(12)**
Balance at end of year	**$ 660**	**$ 640**	**$ 753**	**$ 2,053**

(in millions)	**Pension Plan** **Absolute**	**Fixed-**

For the year ended December 31, 2014	**Return**	**Income**	**Real Assets**	**Total**
Balance at beginning of year	$ 554	$ 625	$ 544	**$ 1,723**
Actual return on plan assets:				
Relating to assets still held at the reporting date	23	24	54	**101**
Relating to assets sold during the period	-	4	-	**4**
Purchases, issuances, sales, and settlements:				
Purchases	-	1	78	**79**
Settlements	-	(16)	(1)	**(17)**
Balance at end of year	**$ 577**	**$ 638**	**$ 675**	**$ 1,890**

	PBOP Plans			
(in millions) **For the year ended December 31, 2015**	**Absolute Return**	**Fixed-Income**	**Real Assets**	**Total**
Balance at beginning of year	$ 55	$ 1	$ 49	**$ 105**
Actual return on plan assets:				
Relating to assets still held at the reporting date	(1)	-	5	**4**
Relating to assets sold during the period	-	-	-	**-**
Purchases, issuances, sales, and settlements:				
Purchases	11	-	23	**34**
Settlements	-	(1)	-	**(1)**
Balance at end of year	**$ 65**	**$ -**	**$ 77**	**$ 142**

	PBOP Plans			
(in millions) **For the year ended December 31, 2014**	**Absolute Return**	**Fixed-Income**	**Real Assets**	**Total**
Balance at beginning of year	$ 53	$ 2	$ 38	**$ 93**
Actual return on plan assets:				
Relating to assets still held at the reporting date	2	-	4	**6**
Relating to assets sold during the period	-	-	-	**-**
Purchases, issuances, sales, and settlements:				
Purchases	-	-	7	**7**
Settlements	-	(1)	-	**(1)**
Balance at end of year	**$ 55**	**$ 1**	**$ 49**	**$ 105**

There were no material transfers out of Level 3 in 2015 and 2014.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $334 million to the pension benefit plans and $61 million to the other benefit plans in 2015. 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 2015. 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 2016.

Benefits Payments and Receipts

As of December 31, 2015, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	Pension Plan	PBOP Plans	Federal Subsidy
2016	$ 695	$ 89	$ (6)
2017	739	95	(7)
2018	780	101	(7)
2019	818	107	(8)
2020	854	113	(8)
Thereafter in the succeeding five years	4,728	593	(17)

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 $89 million, $80 million, and $71 million in 2015, 2014, and 2013, 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)	2015	2014	2013
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 6	$ 5	$ 7
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 53	$ 54	$ 45
Utility employee benefit due to PG&E Corporation	82	70	57

At December 31, 2015 and 2014, the Utility had receivables of $22 million and $17 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 $21 million and $20 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. 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.

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 been made 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 the CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices. A prehearing conference in the OII has been scheduled for March 1, 2016.

The CPUC will determine any penalties that might be imposed on the Utility and determine whether shareholders or ratepayers will bear the costs of the investigation. The CPUC can impose fines up to $50,000 for each violation, per day. 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 this discretion in determining penalties.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII but they are unable to 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, and whether the CPUC will consider additional communications in the OII, including those identified in a motion filed on December 1, 2015, by the City of San Bruno in the 2015 GT&S rate case. It is also uncertain whether the CPUC will take additional action in any of the proceedings in which the Utility has self-reported communications that may have violated the CPUC's ex parte rules.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office also have been investigating matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility is cooperating with the federal and state investigators. 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 requires 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 cites 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, for which the CPUC has previously imposed a penalty of $10.85 million.

On September 30, 2015, the SED submitted its supplemental testimony, which included incidents allegedly related to record-keeping that had not been identified in the initial order, and also asserted violations related to the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities. Evidentiary hearings were held during January 2016. Opening briefs are due by February 26, 2016 and reply briefs are due by March 31, 2016. The SED has indicated it will seek significant penalties, the amount of which is expected to be disclosed in its brief.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the form of fines or other remedies, including possible future unrecoverable costs to implement operational remedies. 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 given the CPUC's wide discretion (discussed above).

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 has been completed and that remediation work, including removal of the encroachments, is 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 or take other enforcement action 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. In addition, the California utilities are required to inform the SED of self-identified or self-corrected violations. The CPUC has delegated authority to the SED to issue citations and impose fines for violations identified through audits, investigations, or self-reports. 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. The SED is required, however, to impose the maximum statutory penalty of $50,000 for each separate violation.

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 fines or take other enforcement action based on some of the Utility's self-reported non-compliance with laws and regulations or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED's audits. 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 has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

Federal Matters

Federal Criminal Indictment

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that superseded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 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. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. The maximum statutory fine for each felony count is $500,000, for total potential fines of $6.5 million. On December 8, 2015, the court also issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act. The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss." The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of gross gains prior to deciding whether to dismiss those allegations. (Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million.) After considering the additional information submitted by the government, on February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges. The trial on the criminal charges currently is scheduled to begin March 22, 2016.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Consolidated Financial Statements as such amounts are not considered to be probable.

Other Federal Matters

The Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. It is uncertain whether any additional charges will be brought against the Utility.

Capital Expenditures Relating to Pipeline Safety Enhancement Plan

At December 31, 2015, approximately $664 million of PSEP-related capital costs is recorded in property, plant, and equipment on the Consolidated Balance Sheets. The Utility would be required to record charges to the statement of income in future periods to the extent total forecasted PSEP-related capital costs are higher than currently expected.

Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission

On April 9, 2015, the CPUC approved final decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record-keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record-keeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. In August 2015, the Utility paid the $300 million fine. At December 31, 2015, the Consolidated Balance Sheets include $400 million in current regulatory liabilities for the one-time bill credit that will be provided to the Utility's natural gas customers in 2016. On January 14, 2016, the CPUC issued final decisions to close these investigative proceedings.

The Penalty Decision requires that at least $689 million of the $850 million disallowance be allocated to capital expenditures, and that the Utility be precluded from including these capital costs in rate base. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the 2015 GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent. The CPUC is expected to issue a final decision in the Utility's 2015 GT&S rate case in 2016 to identify safety-related projects and programs that will be subject to the disallowance. It is uncertain how much of the Utility's costs to perform the safety-related projects and programs the CPUC will identify as counting toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. As a result, the total shareholder-funded obligation could exceed $850 million.

For the year ended December 31, 2015, the Utility recorded additional charges in operating and maintenance expenses in the Consolidated Statements of Income of $907 million as a result of the Penalty Decision. The cumulative charges at December 31, 2015, and the additional future charges to reach the $1.6 billion total are shown in the following table:

(in millions)	**Year Ended December 31, 2015**	**Cumulative Charges December 31, 2015**	**Future Charges and Costs**	**Total Amount**
Fine payable to the state (1)	$ 100	$ 300	$ -	$ 300
Customer bill credit	400	400	-	400
Charge for disallowed capital (2)	407	407	282	689
Disallowed revenue for pipeline safety expenses (3)	-	-	161	161
CPUC estimated cost of other remedies (4)	-	-	-	50
Total Penalty Decision fines and remedies	**$ 907**	**$ 1,107**	**$ 473**	**$ 1,600**

(1) In March 2015, the Utility increased its accrual from $200 million at December 31, 2014 to $300 million.

(2) The Penalty Decision prohibits the Utility from recovering certain expenses and capital spending associated with pipeline safety-related projects and programs that the CPUC will identify in the final decision to be issued in the Utility's 2015 GT&S rate case. The Utility estimates that approximately $407 million of capital spending (which include less than $1 million for remedy related capital costs) in the year ended December 31, 2015 is probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.

(3) These costs are being expensed as incurred. Future GT&S revenues will be reduced for these unrecovered expenses.

(4) In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision and does not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. These costs are being expensed as incurred.

Other Legal and Regulatory Contingencies

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. 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.

Investigation of the Butte Fire

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. The California Department of Forestry and Fire Protection ("Cal Fire") is investigating the source of the Butte Fire to determine whether a tree contacted a power line operated by the Utility and was the cause of the fire. Cal Fire has reported that as a result of the fire there were two deaths and 965 structures, including 571 houses, were damaged or destroyed. Cal Fire's investigation is expected to conclude in 2016.

Approximately 27 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving more than 600 individual plaintiffs and their insurance companies. Plaintiffs and the Utility filed petitions with the California Judicial Council to coordinate these cases. The petitions were assigned to the Calaveras Superior Court for a recommendation to the Judicial Council. On January 21, 2016, the Calaveras Superior Court issued an order recommending to the Judicial Council that the cases be coordinated in the Superior Court of California, Sacramento County, for all purposes including trial. Among other factors, the Court found that coordination requires a court with a significant number of judges and complex litigation support personnel, neither of which are present in Calaveras County.

It is estimated that losses related to structures, contents, other personal property, and fire suppression costs associated with the Butte fire, will range from $350 million to $450 million. This range is based on estimates about the number, size, and type of structures damaged or destroyed, assumptions about the contents of such structures and other personal property damage, and information about the amount of fire suppression costs associated with prior similar fires. The Utility believes that it is reasonably possible that it would be liable for some or all of these and other costs, such as costs associated with tree damage, personal injury, business interruption losses, and other damages. The Utility is unable to reasonably estimate these other costs at this time due to the limited information available.

The Utility has insurance coverage for these types of claims. If the amount of insurance is insufficient to cover the Utility's liability resulting from the Butte fire, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected.

Rehearing of CPUC Decisions Approving Energy Efficiency Incentive Awards

On September 17, 2015, the CPUC issued an order granting TURN's and the ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California investor-owned utilities for the 2006-2008 energy efficiency program cycle. Under the ratemaking mechanism applicable to the 2006-2008 program cycle, the maximum amount of incentives that the Utility could have earned (or the maximum amount that the Utility could have been required to reimburse customers) over the 2006-2008 program cycle was $180 million. The Utility was awarded a total of $104 million for the 2006-2008 program cycle. In the re-opened energy efficiency proceeding, the CPUC will evaluate whether incentives awarded to the California investor-owned utilities were just and reasonable, and whether any refunds are due. The parties are required to submit proposals to resolve the issues in the proceeding by March 18, 2016. Comments on the proposals are due on April 8, 2016 and evidentiary hearings, if needed, would be held in July 2016. It is uncertain when the CPUC will issue a decision and whether the Utility will be required to refund amounts or incur other obligations related to the 2006-2008 program cycle. PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations.

Other Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters" and "Other Legal and Regulatory Contingencies") totaled $63 million at December 31, 2015, and $55 million at December 31, 2014. 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.

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, 2015**	**December 31, 2014**
Topock natural gas compressor station (1)	$ 300	$ 291
Hinkley natural gas compressor station (1)	140	158
Former manufactured gas plant sites owned by the Utility or third parties	271	257
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	164	150
Fossil fuel-fired generation facilities and sites	94	98
Total environmental remediation liability	**$ 969**	**$ 954**

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

At December 31, 2015 the Utility expected to recover $695 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 Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as the "Topock site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

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. On November 4, 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. The clean-up and abatement order did not have a material impact on the Utility's consolidated financial statements.

The Utility's environmental remediation liability at December 31, 2015 reflects the Utility's 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 be performed to implement the final remediation plan 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.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. 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 is conducting an additional environmental review of the proposed design, and the Utility anticipates that the DTSC's draft environmental impact report will be issued for public comment in July 2016. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in December 2016. After the Utility modifies its design in response to the final report, the Utility plans to seek approval to begin construction of the new in-situ treatment system in early 2017.

The Utility's environmental remediation liability at December 31, 2015 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 be performed to implement the final groundwater remedy 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.

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 Hinkley and Topock 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 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 $3.5 billion per nuclear incident and $2.8 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. 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, 2015, the current maximum aggregate annual retrospective premium obligation for the Utility is approximately $60 million.

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 $3.5 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 $3.5 billion policy limit amount.

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. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the California Power Exchange wholesale electricity markets during this period.

At December 31, 2015, and December 31, 2014, the Consolidated Balance Sheets reflected $454 million and $434 million, respectively, in net Disputed claims and customer refunds, including both principal and interest. At December 31, 2015 and 2014, the Utility held $228 million and $291 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

Interest accrues on the remaining net disputed claims liability at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates, these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims liability, the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims liability and when such interest is paid.

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. 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.

In July 2014, a settlement agreement between the Utility and an electric supplier became effective, resolving a portion of the Utility's net disputed claims and resulting in refunds to customers of $312 million. No significant settlement agreements were reached in 2015. The Utility is uncertain when and 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, 2015:

	Power Purchase Agreements					
(in millions)	Renewable Energy	Conventional Energy	Other	Natural Gas	Nuclear Fuel	Total
2016	$ 2,177	$ 772	$ 504	$ 421	$ 113	$ 3,987
2017	2,201	787	380	150	100	3,618
2018	2,075	706	359	105	96	3,341
2019	2,087	694	290	105	98	3,274
2020	2,077	674	213	103	133	3,200

Thereafter	29,098	1,729	997	543	185	32,552
Total purchase commitments	**$ 39,715**	**$ 5,362**	**$ 2,743**	**$ 1,427**	**$ 725**	**$ 49,972**

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 significantly. As of December 31, 2015, renewable energy contracts expire at various dates between 2016 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, 2015, these power purchase agreements expire at various dates between 2016 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, 2015 and 2014, net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $54 million and $74 million including accumulated amortization of $147 million and $128 million, respectively. The present value of the future minimum lease payments due under these agreements included $19 million and $20 million in Current Liabilities and $35 million and $54 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2015, QF contracts in operation expire at various dates between 2016 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 2015, $3.6 billion in 2014, and $3.0 billion in 2013.

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 2016 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $0.9 billion in 2015, $1.4 billion in 2014, and $1.6 billion in 2013.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2016 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 $128 million in 2015, $105 million in 2014, and $162 million in 2013.

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 2016 and 2052. At December 31, 2015, the future minimum payments related to these commitments were as follows:

(in millions)	**Operating Leases**
2016	$ 40
2017	41
2018	40
2019	38
2020	37
Thereafter	194
Total minimum lease payments	**$ 390**

Payments for other commitments related to operating leases amounted to $41 million in 2015, $42 million in 2014, and $40 million in 2013. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period of Report End of 2015/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				13,084,375
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				533,712
3	Preceding Quarter/Year to Date Changes in Fair Value				(8,874,496)
4	Total (lines 2 and 3)				(8,340,784)
5	Balance of Account 219 at End of Preceding Quarter/Year				4,743,591
6	Balance of Account 219 at Beginning of Current Year				4,743,591
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				845,082
8	Current Quarter/Year to Date Changes in Fair Value				(2,365,555)
9	Total (lines 7 and 8)				(1,520,473)
10	Balance of Account 219 at End of Current Quarter/Year				3,223,118

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			13,084,375		
2			533,712		
3			(8,874,496)		
4			(8,340,784)	1,433,077,194	1,424,736,410
5			4,743,591		
6			4,743,591		
7			845,082		
8			(2,365,555)		
9			(1,520,473)	862,018,078	860,497,605
10			3,223,118		

Schedule Page: 122(a)(b)   Line No.: 8   Column: e

Represents unrecognized pension and PBOP costs per ASC 715.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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)	61,682,406,216	44,766,091,208
4	Property Under Capital Leases	220,067,044	201,230,789
5	Plant Purchased or Sold	-4,939	-100,000
6	Completed Construction not Classified	9,672,852,987	5,823,047,559
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	71,575,321,308	50,790,269,556
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,057,204,814	1,540,672,392
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	73,632,526,122	52,330,941,948
14	Accum Prov for Depr, Amort, & Depl	32,001,238,924	23,015,171,357
15	Net Utility Plant (13 less 14)	41,631,287,198	29,315,770,591
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	31,110,855,009	22,960,835,099
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	7,930,342	
21	Amort of Other Utility Plant	882,453,573	54,336,258
22	Total In Service (18 thru 21)	32,001,238,924	23,015,171,357
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)	32,001,238,924	23,015,171,357

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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
11,534,580,098				5,381,734,910	3
				18,836,255	4
-337,617				432,678	5
3,081,925,152				767,880,276	6
					7
14,616,167,633				6,168,884,119	8
					9
					10
239,928,947				276,603,475	11
					12
14,856,096,580				6,445,487,594	13
6,657,772,454				2,328,295,113	14
8,198,324,126				4,117,192,481	15
					16
					17
6,647,576,881				1,502,443,029	18
					19
7,930,342					20
2,265,231				825,852,084	21
6,657,772,454				2,328,295,113	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
6,657,772,454				2,328,295,113	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	02/24/2016	End of 2015/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	246,107,680	134,043,321
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	246,107,680	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	389,415,071	95,149,914
10	SUBTOTAL (Total 8 & 9)	389,415,071	
11	Spent Nuclear Fuel (120.4)	1,970,583,455	97,165,126
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,133,540,139	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	472,566,067	
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
	95,149,914	285,001,087	3
			4
			5
		285,001,087	6
			7
			8
	97,165,125	387,399,860	9
		387,399,860	10
		2,067,748,581	11
			12
-122,902,702		2,256,442,841	13
		483,706,687	14
			15
			16
			17
			18
			19
			20
			21
			22

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

Cost of fuel inserted into reactor during 2015; 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 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	111,911,658	1,838,412
4	(303) Miscellaneous Intangible Plant	11,130,080	7,964
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	123,041,738	1,846,376
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	7,007,089	1,562,537
9	(311) Structures and Improvements	111,011,184	1,114,054
10	(312) Boiler Plant Equipment	274,379,838	-886,146
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	248,783,088	
13	(315) Accessory Electric Equipment	48,952,677	1,744,435
14	(316) Misc. Power Plant Equipment	28,265,952	29,626
15	(317) Asset Retirement Costs for Steam Production	82,534,510	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	800,934,338	3,564,506
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	22,726,561	
19	(321) Structures and Improvements	1,013,513,229	42,843,769
20	(322) Reactor Plant Equipment	3,374,527,719	64,392,461
21	(323) Turbogenerator Units	1,150,875,307	17,244,899
22	(324) Accessory Electric Equipment	799,434,516	16,405,054
23	(325) Misc. Power Plant Equipment	970,791,200	90,497,674
24	(326) Asset Retirement Costs for Nuclear Production	1,313,483,579	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	8,645,352,111	231,383,857
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	41,719,581	694,428
28	(331) Structures and Improvements	391,139,167	38,132,977
29	(332) Reservoirs, Dams, and Waterways	1,897,235,553	51,320,864
30	(333) Water Wheels, Turbines, and Generators	681,997,389	136,397,469
31	(334) Accessory Electric Equipment	234,972,389	20,066,729
32	(335) Misc. Power PLant Equipment	86,295,939	1,784,725
33	(336) Roads, Railroads, and Bridges	71,618,809	2,278,420
34	(337) Asset Retirement Costs for Hydraulic Production	6,363,071	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	3,411,341,898	250,675,612
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,207,870	
38	(341) Structures and Improvements	210,381,186	-5,532
39	(342) Fuel Holders, Products, and Accessories	11,246,468	17,650
40	(343) Prime Movers	223,711,698	
41	(344) Generators	353,866,690	-295,749
42	(345) Accessory Electric Equipment	210,706,075	-30,513
43	(346) Misc. Power Plant Equipment	95,332,442	535,124
44	(347) Asset Retirement Costs for Other Production	2,682,358	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,127,134,787	220,980
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	13,984,763,134	485,844,955

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	237,862,320	8,805,500
49	(352) Structures and Improvements	392,966,752	23,129,310
50	(353) Station Equipment	4,766,343,999	535,765,148
51	(354) Towers and Fixtures	652,338,260	131,210,809
52	(355) Poles and Fixtures	812,955,115	86,595,229
53	(356) Overhead Conductors and Devices	1,294,964,218	101,961,153
54	(357) Underground Conduit	351,167,088	90,560
55	(358) Underground Conductors and Devices	256,254,506	1,854,656
56	(359) Roads and Trails	54,438,703	9,396,155
57	(359.1) Asset Retirement Costs for Transmission Plant	2,538,657	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	8,821,829,618	898,808,520
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	177,095,381	356,348
61	(361) Structures and Improvements	310,003,234	5,174,232
62	(362) Station Equipment	2,809,962,827	207,093,917
63	(363) Storage Battery Equipment	32,749,153	65,492
64	(364) Poles, Towers, and Fixtures	3,442,261,983	306,185,751
65	(365) Overhead Conductors and Devices	4,074,756,384	248,624,103
66	(366) Underground Conduit	2,565,753,273	86,823,868
67	(367) Underground Conductors and Devices	3,875,237,699	226,933,760
68	(368) Line Transformers	2,675,280,857	269,942,427
69	(369) Services	2,909,588,671	102,390,787
70	(370) Meters	1,049,036,783	40,352,907
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	201,850,787	11,004,574
74	(374) Asset Retirement Costs for Distribution Plant	11,099,524	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	24,162,885,916	1,504,948,166
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	11,120,707	134,156
88	(391) Office Furniture and Equipment	14,552,056	685,052
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	90,985,139	12,999,865
92	(395) Laboratory Equipment	14,898,419	8,910
93	(396) Power Operated Equipment	292,081	
94	(397) Communication Equipment	17,145,627	118,991,901
95	(398) Miscellaneous Equipment	49,177,142	8,861,287
96	SUBTOTAL (Enter Total of lines 86 thru 95)	198,595,803	141,681,171
97	(399) Other Tangible Property	468,499,422	-739
98	(399.1) Asset Retirement Costs for General Plant	6,924,694	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	674,019,919	141,680,432
100	TOTAL (Accounts 101 and 106)	47,766,540,325	3,033,128,449
101	(102) Electric Plant Purchased (See Instr. 8)	-365,858	365,858
102	(Less) (102) Electric Plant Sold (See Instr. 8)	-51,399	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	47,766,225,866	3,033,494,307

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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
			113,750,070		3
8,655,768			2,482,276		4
8,655,768			116,232,346		5
					6
					7
			8,569,626		8
			112,125,238		9
			273,493,692		10
					11
			248,783,088		12
			50,697,112		13
			28,295,578		14
	9,655,047		92,189,557		15
	9,655,047		814,153,891		16
					17
			22,726,561		18
19,613,733			1,036,743,265		19
6,436,955			3,432,483,225		20
5,309,152			1,162,811,054		21
5,950,030			809,889,540		22
5,240,385			1,056,048,489		23
			1,313,483,579		24
42,550,255			8,834,185,713		25
					26
72,739			42,341,270		27
664,140		-171,701	428,436,303		28
-1,938,602		171,701	1,950,666,720		29
31,066,786			787,328,072		30
1,447,642			253,591,476		31
843,073			87,237,591		32
744,359			73,152,870		33
	837,356		7,200,427		34
32,900,137	837,356		3,629,954,729		35
					36
			19,207,870		37
			210,375,654		38
			11,264,118		39
			223,711,698		40
			353,570,941		41
			210,675,562		42
			95,867,566		43
	-2,682,358				44
	-2,682,358		1,124,673,409		45
75,450,392	7,810,045		14,402,967,742		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
275,988		-862,035	245,529,797		48
249,843		161,187	416,007,406		49
18,133,266		10,441,980	5,294,417,861		50
87,570		2,707,556	786,169,055		51
629,970		428,993	899,349,367		52
13,616,788			1,383,308,583		53
			351,257,648		54
159,535			257,949,627		55
			63,834,858		56
	294,417		2,833,074		57
33,152,960	294,417	12,877,681	9,700,657,276		58
					59
32,557		-361,745	177,057,427		60
14,829		-258,176	314,904,461		61
13,510,419		-3,426,974	3,000,119,351		62
			32,814,645		63
11,901,922	632,931	-6,866,587	3,730,312,156		64
31,747,548		-1,979,719	4,289,653,220		65
18,033		-279,837	2,652,279,271		66
7,014,173		-47,534	4,095,109,752		67
28,829,579		-2,130	2,916,391,575		68
407,230		-45,793	3,011,526,435		69
9,459,846	-149,454		1,079,780,390		70
			27,313,912		71
			895,448		72
9,154			212,846,207		73
	2,324,205		13,423,729		74
102,945,290	2,807,682	-13,268,495	25,554,427,979		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			424,632		86
			11,254,863		87
105,693			15,131,415		88
					89
					90
			103,985,004		91
503,650			14,403,679		92
20,469			271,612		93
122,759		105,238	136,120,007		94
352,274			57,686,155		95
1,104,845		105,238	339,277,367		96
		739	468,499,422		97
	151,941		7,076,635		98
1,104,845	151,941	105,977	814,853,424		99
221,309,255	11,064,085	-284,837	50,589,138,767		100
					101
	151,399		100,000		102
					103
221,309,255	10,912,686	-284,837	50,589,038,767		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	02/24/2016	End of 2015/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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22					
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31					
32					
33					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	31103076 EMBARCADERO-POTRERO 230KVCABLE?SUB	42,781,000
2	30605684 61-NEW 230 KV SWITCHYARD AT POTRERO	41,683,445
3	30605330 94-EMBARCADERO SUB 230KV BUS UPGRADE	38,171,541
4	68005100 Lead Order-License Renewal Application	37,189,477
5	31085503 EMBARCADERO-POTRERO 230KVCABLE#DUCT BANK	36,009,692
6	7054908 MC-P Relic- Project Management	29,280,467
7	68020627 PLO-Procure Casks/Prj Supprt-Campaign 6	22,353,631
8	68001801 Lead Order-U1:Repl Eagle-21 System	19,762,063
9	31085840 EMBARCADERO-POTRERO 230KVCABLE#HDD	19,462,914
10	7070913 DS conduct Relicensing studies	18,748,593
11	30605686 60-EMBARCADERO-POTRERO 230KV LINE	17,943,237
12	30983382 EMBARCADERO-POTRERO 230 KV CABLE #SUBMAR	17,879,134
13	7068905 Belden Repl Runner Wickets & FP's	15,919,178
14	68016546 PLO- NFPA 805 ERFBS U1 LT-529 WRAP CONDU	14,304,362
15	30803908 OAKLAND X: REPLACE 12 KV SWITCHGEAR	13,584,526
16	7021725 UNFFR Relic Routine Project Management	11,855,415
17	68034400 COM: PLO- Protective Strategy Upgrade	11,404,546
18	68016662 PLO-U1:NFPA 805 Fire Detection Sys Upgr	11,221,636
19	68016664 PLO-U1:NFPA 805 Hot Shutdown Panel Upgr	10,433,156
20	30782983 60-VACA-LAKEVILLE: RECOND 230KV LINE	10,397,667
21	30803902 MIDWAY - REPL 500KV REACTOR #3 & CS 727	9,885,308
22	13004820 Drum Spaulding - Developing PAD and NOI	9,616,468
23	30882294 SAN MATEO SUB: SECURITY UPGRADE	9,286,341
24	68001812 Lead Order-U2:Repl Eagle 21 System	9,174,515
25	7026033 UNFFR Relic Aquatic Resource Stdy	9,149,165
26	31021813 MORAGA TRANSFORMER NO.2 REPLACEMENT	8,702,438
27	30953194 DCPP SUBSTATION ? REPLACE 500 KV SWITCH	8,133,977
28	30985932 OAKLAND C: REPLACE BANK #1	8,042,891
29	13003982 DS-C Relic- Cond studies for all RA	7,889,145
30	30985917 61-NEW 230 KV SWITCHYARD AT POTRERO	7,672,801
31	30992248 GREATER BAY AREA RESTORATION PLAN (SF)	7,424,173
32	30898665 COTTONWOOD-DELEVAN #2 230KV NERC	7,385,308
33	68018981 PLO-CRVS Design Vulnerability	7,302,468
34	30784089 NC GLENN SUBSTATION BUS RELIABILITY	7,256,272
35	74001423 MISSOURI FLAT-GOLD HILL 115 KV - LINE	7,155,986
36	30712802 60-CONTRA COSTA-MORAGA LINE-1 RECOND	7,114,512
37	68016665 PLO-U2:NFPA 805 Hot Shutdown Panel Upgr	6,896,916
38	74001178 NV_67-STOCKTON A 115/60KV MPAC	6,565,003
39	30822460 SF RAS A: REPLACE SYSTEM AT SFGO	6,401,143
40	7017646 Poe Relic - Prepare Exhibit E	6,170,718
41	13015382 Kerckhoff Dam - Repl LLO Gates	5,929,417
42	30779044 NV_WEBER SUB: REPL 230/60 KV TXFR 2 & 2A	5,882,719
43	TOTAL	1,540,672,392

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	30970515 DRUM-RIO OSO #1 115KV NERC STEEL	5,860,680
2	30777381 NV_WEBER SUB: 60KV BUS RELIABILITY IMPRV	5,836,385
3	30632553 SOBRANTE: ADD AND REPL 14-115KV BKERS	5,741,518
4	7011106 Poe Relic - Project Management	5,592,753
5	30818254 NC_EUREKA E SUB: REPL 60KV STRUCTURE	5,504,303
6	30764700 61-CHRISTIE SUB: INSTALL BANK 2	5,446,611
7	68011748 PLO-U2:Repl Main Generator Stator (2R20)	5,441,949
8	7083025 63D-DCC Pre Conslidation Prjct Cap Suppt	5,335,587
9	7026032 UNFFR Relic Water Use & Qlty Stdy	4,935,123
10	30986088 SOBRANTE: ADD AND REPL 14-115KV BKERS	4,864,191
11	30770725 NC_EEL RIVER SUB: INSTALL BK 2	4,745,955
12	7026037 UNFFR Relic Land Use/Mgt Study	4,725,671
13	30603607 PEASE-MARYSVILLE 60KV SUB CONV-MRYSVL	4,672,428
14	7076869 Buck Relicensing Studies	4,639,342
15	7058680 Permit Holdover Project - Distribution	4,569,269
16	7055507 DS Relic- Strategic Planning	4,566,692
17	30984573 IJ2/IJ3 CABLE REPLACEMENT - EB 2014	4,455,600
18	30895387 METCALF-MOSS LANDING #1 & #2 230KV NERC	4,432,982
19	31039100 GATE-GREGG 230KV T-LINE CPUC LIC/PER	4,415,135
20	13005520 Kilarc Cow Decom Project Management	4,372,066
21	30651779 NC_WINDSOR:ARCHVE PERMITTING_LAND SUPPRT	4,322,264
22	31017263 BRIGHTON-BELLOTA 230KV NERC PROJECT	4,222,749
23	30983549 64-230KV CONV\BAAH\REBUILD	4,218,617
24	7055646 DS Relic- Project Management	4,020,467
25	31103714 SYNCHROPHASOR DEMONSTRATION - DOE GRANT	3,796,774
26	31017518 NC_EUREKA E: REPL 12KV CBS & STRUCT	3,714,724
27	31066290 INSTALL LPTS IN 6 SF 115KV UG CKTS	3,543,099
28	30616106 WALNUT AVE., WINTON R20A	3,504,006
29	13009501 Poe Replace Cooling Water System	3,353,204
30	30878724 KERCKHOFF-CLOVIS-SANGER #1 RELIABILITY	3,310,595
31	30797619 OAKLEY GENERATING STN: LAS POSITAS-NEWAR	3,305,177
32	68024820 PLO-U1:PRA Sump Debris Mitigation Analys	3,302,089
33	68012041 PLO-U1:Replace U1 FLUR/SLUR Relays	3,296,462
34	74000996 67-OLEUM PP - INSTALL 115 KV MPAC	3,289,666
35	30996434 HUNTERS POINT: 115KV GIS BAAH	3,242,737
36	68027382 PLO-COM:TS Setpoint Calcs Rev & Reloc	3,233,265
37	31171925 JOLON BANK 06A FEEDER WORK	3,086,429
38	30763887 60-GREEN VALLEY-WATSONVILLE 60KV-115KV	3,067,182
39	30764804 67-MARTINEZ PP: 115 KV MPAC	3,066,295
40	7069447 License Surrender Application	3,037,086
41	30900007 RIO OSO-WOODLAND #1 & #2 115KV NERC	3,016,771
42	7049829 DC Relic Begin Prep of NOI and PAD	3,013,757
43	TOTAL	1,540,672,392

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	68015281 PLO-U2:Repl Cavity Seal with Permnt Seal	3,002,743
2	13006580 Merced Falls	2,999,190
3	31017506 NC_SAN RAFAEL: REPL BK2	2,969,920
4	7086446 Dynamic Automated Seismic Hazard System	2,960,329
5	68014363 U1 SFP Bridge Crane Upgrades	2,856,811
6	30644546 64-MOSS LANDING 115 KV BUS TO BAAH	2,838,946
7	30977586 NC_TABLE MTN REPL CBS 212,222,282,312	2,792,564
8	7053945 DC Relic - Prepare Study Plans	2,722,257
9	31035789 EMBARCADERO (SF-Z) DECOUPLE BKS 1, 3, 5	2,691,954
10	7043247 RCC Lic Imp Cold Water Feasibility Study	2,687,809
11	30874162 61-PITTSBURG-LAKEWOOD SPS CLAYTON	2,681,054
12	74000600 FULTON-FITCH MTN. RECOND 60KV LN	2,657,780
13	13017020 Balch 2 Unit 3 Generator Rewind	2,657,586
14	30986093 NV_RIPON SUB: BUILD 2ND 115 KV LINE	2,653,285
15	30901897 DRUM-RIO OSO #2 115KV NERC STEEL	2,641,722
16	68038982 PLO: Security Defensive Strategy Upgrade	2,631,120
17	31137241 NV_E. NICOLAUS SUB:PH. 2,REPLACEMENT OB	2,616,935
18	30855195 NV_61-FRENCH CAMP SUB:INSTALL 60 KV CB'S	2,602,186
19	30910838 60-SOUTH OF PALERMO REINFORCEMENT (PH-1)	2,598,008
20	68017441 PLO-Repl Met Tower Computer & Recorders	2,583,426
21	30977584 NV_MOSHER RING BUS COMPLETION & RAS ADD	2,564,584
22	31021595 FREMONT: REPLACE BANK #2 (CONST 2016)	2,549,494
23	7026034 UNFFR Relic Terres Resources Stdy	2,540,208
24	68015242 PLO-COM::Rplc Secondary Chem Lab	2,538,598
25	68014364 U2 SFP Bridge Crane Upgrades	2,528,104
26	30813727 MARTIN-EMBARCADERO #2 (HZ-2) 230KV RELOC	2,526,966
27	30903241 EL CERRITO G: 115KV BUS UPGRADE PHASE 1	2,525,145
28	31087348 61-MENLO SUB: 60KV SWITCH REPLACEMENT	2,516,907
29	13011999 Kerckhoff 2-Replace Draft Tube Section	2,455,926
30	30784704 61-WEBER SUB:IMP 60 KV #1 RADIAL STATION	2,441,724
31	31084384 VACAVILLE CONTROL ROOM VIDEO WALL	2,436,206
32	13019680 Tiger Creek Road - Re-Pave 2.1 Miles	2,434,360
33	30761606 NC_IGNACIO/ ALTO- 60 KV LINE W/ CB	2,430,452
34	30803905 EL CERRITO G: REPL BK 4 115-12KV, 60MVA,	2,427,461
35	30842587 OAKLEY GENERATING STN:COCOPP-DELTA PUMPS	2,423,395
36	31031500 Q643W MUSTANG T-LINE (NU)	2,422,506
37	13006140 MC-P Relic- Conduct Relicensing Studies	2,419,315
38	30992521 NICWILKSLO SET 35 POLE OPERATIVE	2,400,462
39	31103074 EMBARCADERO-POTRERO 230KVCABLE?LAND	2,396,600
40	30603543 PEASE-MARYSVILLE 60KV LNCNV (PEASE SU	2,391,870
41	68016640 PLO-U1:Replace Cavity Seals	2,386,016
42	31023065 Q356 CUYAMA (NU) CUYAMA SUB	2,384,892
43	TOTAL	1,540,672,392

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	74000924 ESTRELLA_CPUC LIC/PER	2,380,095
2	68016342 PLO- U2:Instl Passive RCP Thermal Seal	2,357,072
3	30766763 NV_67-KASSON SUB: 115/60KV MPAC	2,346,705
4	31073083 SALINAS SUB # REPLACE 60 KV SWITCHES, BU	2,324,709
5	7054909 MC-P Relic- Prepare NOI and PAD	2,315,739
6	68034401 COM:PLO-Instl Sec Holding Area HVAC	2,315,693
7	7017635 Poe Relic Field Study/Aquatic Res	2,315,521
8	13018361 TC Canal-Install Canal Liner 2015/2016	2,294,432
9	30759856 METCALF SUB:PHASE1&2,REPLACE OB INSULATO	2,293,577
10	30920840 METCALF SUB_INSTALL FIRE WALLS DRS 2013-	2,267,188
11	13002402 DS-C Relic- Conduct Pre-App Proj Man	2,265,803
12	74001688 NC_EPC_MAPLE CREEK SUB:REACTIVE SUPPORT	2,264,952
13	68039543 PLO:U2-Repl Rod Cntrl Sys Circuit Crds,	2,260,816
14	74001039 LARKIN: REPL 12KV SWGR	2,258,728
15	13007743 Potter Valley Repl Lower Woodstave Pnstk	2,256,919
16	30995497 NV_2015: REPLACE CORDELIA BANK #2	2,246,614
17	31017513 R2 BERRENDA A: REPLACE 70/4KV BK 1	2,237,900
18	68018677 Support 02*998 PPS (EAGLE 21) PARTS U2	2,236,366
19	68024821 PLO-U2:PRA Sump Debris Mitigation Analys	2,183,007
20	30989151 GREATER BAY AREA RESTORATION PLAN (OAK)	2,149,288
21	31059018 MOSS LANDING: TECH SECURITY UPGRADE	2,140,206
22	30874163 61-PITTSBURG-LAKEWOOD SPS LAKEWOOD	2,114,496
23	30876482 GATES-GREGG PRE-BID COSTS	2,113,327
24	7072819 Helms - Replace Liquid Rheostat	2,104,717
25	68020304 COM:Repl Public Address System Phase II	2,093,951
26	31031509 Q643X TRANQUILLITY MCMULLIN SUB (NU)	2,092,335
27	30801125 FRTP-SPS-CALIFORNIA SUB (FOC	2,084,356
28	7021727 UNFFR Relic Prepare 5 Year Library	2,074,194
29	7085351 63-Alternate GCC IT Infra at Rocklin	2,062,498
30	30760811 COTTNWD-RED BLUFF - RECONDUCTOR	2,062,496
31	30827391 R6 OLD CNTY RD BELMONT PH1 R20A	2,055,051
32	30848029 R2 KERN-O.R #2 PANAMA SUB TO OLD RIVER	2,040,099
33	30979928 COCO SW STATION SERVICE PROJECT	2,039,496
34	13009580 DeSabla Replace Governor	2,028,457
35	68014444 PLO-U1:Replace Main Gen Output Breaker	2,023,757
36	13014221 Pit 1 Replace Trash Rake and Rack	2,001,643
37	30983411 61-MORAGA SUB 230KV UPGRADE	1,961,954
38	13015400 Helms - Main Crane Modifications	1,950,647
39	7060966 COM:Instl Bar Rack Rake System	1,947,588
40	31168438 SAN MATEO-MARTIN 230 KV UG CABLE	1,937,248
41	31017549 GOLD HILL-BELLOTA-LOCKEFORD NERC PROJECT	1,928,598
42	68006140 Lead Order-U2:Repl FLURs/SLURs	1,925,062
43	TOTAL	1,540,672,392

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	30968128 Q532 WHITNEY POINT SOLAR SW STATION MPAC	1,923,549
2	74001175 RE- EST- MOSHER-LOCKEFORD 60KV RECOND.	1,902,651
3	31039328 0127-MARICOPA EAST @ LAKEVIEW SUB EXPAN	1,883,278
4	7026036 UNFFR Relic Rec Resources Study	1,876,592
5	74000907 PIT 4 U2 REPLACE RUNNER	1,870,146
6	30822461 NV_INSTALL RIPON BANK 1 (MWC 46)	1,856,272
7	7088286 Documentum /Brava SW & Support	1,855,179
8	74000925 MIDWAY ANDREW_CPUC LIC/PER	1,842,740
9	13018463 2015 Hydro Waterways Public Safety Impr.	1,835,066
10	30924121 MIDWAY FAULT DUTY MITIGATION PROJECT	1,814,857
11	13009582 Helms Repl Crtrt ID/T1 Gate Controls	1,811,022
12	68031182 PLO: COM-Upgrade Bldg 101 (WCC 119')	1,780,902
13	7086685 HBGS Purchase Spare 60kV Transformer CEM	1,780,028
14	31000868 MERCED-MERCED FALLS RELIABILITY PH2	1,776,684
15	68016661 PLO-U2:Install NFPA 805 ERFBS FCV-95 RE-	1,733,630
16	30620382 61-MENLO SUB: 60KV SWITCH REPLACEMENT	1,724,492
17	7086465 Upgrade PGE.com - Tier 1 app (Capital)	1,709,223
18	74000939 WRJ NONCOMPETITIVE_CPUC LIC/PER	1,700,422
19	13015140 Rock Cr Repl Stoplog Hoist	1,697,383
20	31019043 GATES BAAH #2 500/230 KV	1,677,474
21	74000551 PEASE-MARYSVILLE 60KV LINE PROJECT	1,674,984
22	13009603 Install New Gages SBX7_8 - Central	1,614,810
23	13014020 Poe Replace U1 Governor	1,583,096
24	7026029 UNFFR Relic Prep 1st Stage Consult Pkg	1,562,626
25	30881493 SEMITROPIC-REPL CB 1106,1108,1112	1,541,201
26	30801124 FRTP-SPS-BORDEN SUB	1,535,718
27	31166991 TABLE MOUNTAIN BANK/BREAKER MONITOR	1,535,586
28	30763883 61-GREEN VALLEY:115 KV BUS UPGRADE BAAH	1,525,015
29	68020200 PLO: U2: REPL CFCU CLNG COILS (2R19) 2-5	1,522,138
30	30551318 (CONT.EST)ELECTRA-VALLEY SPRINGS CAP REC	1,492,250
31	74000933 LOCKEFORD-LODI_CPUC LIC/PER	1,488,181
32	68012135 PLO-U1 Instl ICW HdTk N2 Cover Gas	1,477,613
33	7074086 Helms - Replace HPCO HPU	1,474,201
34	31164848 SPRING NONCOMPETITIVE_CPUC LIC/PER	1,474,148
35	31031511 Q643X TRANQUILLITY SWITCHING ST (NU)	1,456,280
36	30853599 NV_GRASS VALLEY: INSTALL: SCADA	1,441,067
37	30764536 61-PITTSBURG-LAKEWOOD SPS PITTSBURG PP	1,438,264
38	7071845 Balch - Install Sewer Pipe	1,437,755
39	7088025 Upgrade PGE.com - Mobile	1,419,700
40	13014224 Pit 1 Fall R. Rp Weir & Gate Structure	1,411,289
41	30881944 LOST HILLS (NU) CARNERAS SUB	1,409,889
42	30615218 NV_RIO OSO SUB BANKS #1 & #2	1,408,413
43	TOTAL	1,540,672,392

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	31165126 NC_ALLEGHANY BANK 1 REPLACEMENT	1,406,886
2	31031715 Q829 PANOCHE SWITCHING STATION (NU)	1,393,230
3	74001179 NV_94-INDIAN FLAT SUB:REPL SW 17 W/1-70K	1,376,731
4	74000160 93-SALINAS #1 AND #2 REPL LSP W/ TSP	1,376,123
5	30760807 GARBRVLLE-LAYTNVLLE PHASE 2 SEG 4	1,374,358
6	30945907 DONNELLS-CURTIS 115KV NERC (CONTRACTOR)	1,370,245
7	13019045 Kerckhoff 2 - Repl Bearings/Install RTDs	1,370,210
8	13002403 DS-C Relic- Conduct Studies	1,356,909
9	30854116 NV_GRASS VALLEY: INSTALL: D-SCADA	1,355,963
10	7087405 CGS ACC Fan Blade Replacement	1,348,637
11	30853455 NC_BUTTE SUB: INSTALL T-SCADA	1,344,658
12	13009422 Electra Modify Diversion	1,343,824
13	30930320 LARKIN: REPL 115-12KV BANK 6	1,340,142
14	30951935 ROCK CREEK-POE 230KV NERC PROJECT	1,339,629
15	13007443 Philadelphia S-83 Weir & Controls Modifi	1,330,602
16	30968215 CUYAMA SOLAR (NU) TAFT SUB	1,319,439
17	13011860 Pit 6 Replace Trash Rake	1,315,580
18	30795046 67-NEWARK SUB - REPL. GE UR RELAY	1,314,634
19	30829426 NV_MANTECA: UPGRADE DIST PROT RELAYS	1,307,236
20	31186964 EP NORTH MIDWAY ROAD TRACY	1,304,817
21	13008740 Battle Crk - Phase 2 License Amendment	1,303,268
22	7062249 MC-P- Proj Scoping and Study Plan Devp	1,292,733
23	30651126 67-INSTALL FIRE PROTECTION CONTROLS-MPAC	1,289,883
24	31031506 Q643X TRANQUILLITY T-LINE (NU)	1,288,618
25	7070917 DS Post App filing activities	1,288,376
26	68034341 PLO:COM Repl MSLB 4kV Switchgear Louvers	1,284,044
27	30877693 NV_67 - PANOCHE 115KV MPAC	1,282,173
28	68008644 Lead Order-U2 FHB Supply Fan Replace	1,259,616
29	74000853 UPGRADE RIO OSO 230KV SUBSTATION	1,257,680
30	31055804 Q679 BURFORD GIFFEN-GIFFEN SUB BUS-(NU)	1,255,541
31	30992643 SILICON VALLEY RAPID TRANSIT MILPITAS SU	1,247,350
32	31017267 MIDDLE FORK-GOLD HILL NERC PROJECT	1,241,020
33	31056620 METCALF 500KV LINE	1,236,803
34	30954852 FRTP-SPS-NEW MELONES (WAPA)	1,234,608
35	13018440 Helms GSU Transformer Heat Exchanger Rep	1,228,801
36	7049828 DC Relic Project Management	1,228,571
37	30968125 Q532 WHITNEY POINT SOLAR SCHINDLER DTT-S	1,219,654
38	7017638 Poe Relic Field Study/Recreation	1,217,229
39	31077675 EP Q356 CUYAMA SOLAR NU - PELLATO PEAK/H	1,208,578
40	68019301 U1:Upgrade Polisher Computer Workstation	1,206,805
41	31017525 MARTIN SUB: REPL 12KV BUS G W/VACUM SWGR	1,198,883
42	7081607 Pegasus Bakersfield Yard Relocation	1,196,005
43	TOTAL	1,540,672,392

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	31161611 KERN-O.R #2 PANAMA SUB TO OLD RIVER	1,183,885
2	30898667 DELEVAN-CORTINA 230KV NERC	1,179,952
3	30977258 LAKEVIEW SUB - REPLACE CBS 22, 32	1,173,187
4	13011944 Caribou 2 U5 Rebuild Governor	1,160,863
5	7055645 DS Relic- Coord Study w/ NID	1,160,849
6	7081546 Hayward O'Neil GC Yard Blding (Electric)	1,156,235
7	70029220 CIP005 -WP10 F Advanced Network Protecti	1,151,098
8	30773504 FRTP-SPS-GATES SUB	1,149,961
9	7083173 SG Line Sensors Ph1 - ATS	1,146,299
10	68012133 PLO-U1: Instl SCW HdTk N2 Cover Gas	1,127,948
11	31051302 NV_TESLA 500KV LINE	1,127,455
12	31021062 SHAFTER SUB INSTALL BK2	1,122,144
13	74000709 HUMB BAY-HUMB #1 RE-CONDUCTOR LINE	1,116,039
14	13012004 Fordyce Dam Leakage Reduction	1,110,472
15	31031900 Q829 PANOCHE TLINE (NU)	1,107,987
16	68012920 PLO-U1:Add Iso Vlvs SI Test Hdr Phase II	1,105,362
17	30882299 MERCED-MERCED FALLS RELIABILITY PH1	1,098,011
18	30563618 EL CAMINO REAL SM/SLO CNTY R20A	1,096,690
19	31126606 NC_ROCK CREEK REPLACE SW'S EMERGENCY	1,094,342
20	13011921 NFSL Additional Design Imp	1,087,812
21	31053377 REPLACE SANTA MARIA BK 2	1,079,993
22	30773516 FRTP-SPS-GREGG SUB	1,072,319
23	13011866 Pit 3 Unit 3 Governor Replacement	1,070,140
24	30853643 67-INSTALL SCADA @ MONTA VISTA	1,066,818
25	31166990 Metcalf Sub: Substation Condition Asset	1,065,510
26	68010300 U1:Replace 12kv Protection Relays	1,058,197
27	13015521 Hydro Dam Security-Salt Springs Dam	1,056,922
28	74001105 SOBRANTE REPL BK 2 (230-115KV, 420 MVA)	1,056,008
29	30773514 NV_FRTP-SPS-WILSON SUB	1,055,597
30	31186691 UPGRADE SUSTAINMENT	1,051,279
31	30910554 NV_GRASS VALLEY REP 12KV BUS STRUCTURE	1,046,887
32	74000901 MARTIN BUS EXTENSION_CPUC LIC/PER	1,037,135
33	30968847 Q581 HENRIETTA TLINE (NU)	1,033,239
34	68036566 PLO- Upgrd Bldg 116 Entire 2nd Floor	1,032,084
35	68040701 PLO: U1 NI Replacements 1R19	1,030,874
36	30874164 61-PITTSBURG-LAKEWOOD SPS MEADOW LANE	1,019,394
37	30993611 NV_ATHENS SUBSTATION PURCHASE	1,018,559
38	7086449 IT for base camps	1,017,999
39	30955198 SF AIRPORT-SAN MATEO 115KV (HC) NERC PRJ	1,004,233
40	68000146 Lead Order-U2:Repl Boric Acid Xfer Pumps	1,001,003
41	74001177 NV_EPC_STOCKTON A SUB: INSTALL MRTU	1,000,329
42	See footnote for description.	387,828,241
43	TOTAL	1,540,672,392

Schedule Page: 216.6 Line No.: 42 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	21,765,293,827	21,765,293,827		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,728,219,651	1,728,219,651		
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	-131,562,501	-131,562,501		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,596,657,150	1,596,657,150		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	212,653,486	212,653,486		
13	Cost of Removal	176,670,054	176,670,054		
14	Salvage (Credit)	11,734,302	11,734,302		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	377,589,238	377,589,238		
16	Other Debit or Cr. Items (Describe, details in footnote):	-23,526,640	-23,526,640		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	22,960,835,099	22,960,835,099		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	352,907,149	352,907,149		
21	Nuclear Production	6,102,379,149	6,102,379,149		
22	Hydraulic Production-Conventional	1,294,748,960	1,294,748,960		
23	Hydraulic Production-Pumped Storage	750,652,208	750,652,208		
24	Other Production	190,613,509	190,613,509		
25	Transmission	2,635,514,594	2,635,514,594		
26	Distribution	11,105,218,115	11,105,218,115		
27	Regional Transmission and Market Operation				
28	General	528,801,415	528,801,415		
29	TOTAL (Enter Total of lines 20 thru 28)	22,960,835,099	22,960,835,099		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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			4,000,000
4	Undistributed Earnings			190,655
5				
6	SUBTOTAL			4,191,655
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			
18	Undistributed Earnings			-3,449,508
19				
20	SUBTOTAL			-3,439,508
21				
22	Standard Pacific Gas Line Incorporated			
23	Common Stock	1930-32		1,200
24	Additional Paid in Capital	1954		29,324,574
25	Undistributed Earnings			-24,488,673
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			29,155,277
35				
36	Midway Power LLC			
37	Additional Paid in Capital	2008		25,440,583
38	Undistributed Earnings			-18,246,150
39				
40	SUBTOTAL			7,194,433
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	39,484,076

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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		2,535,597
3	Undistributed Earnings			-153,378
4				
5	SUBTOTAL			2,382,219
6				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	39,484,076

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
		3,248,680		3
-92,718		97,937		4
				5
-92,718		3,347,617		6
				7
				8
		100,000		9
		3,037,432		10
		-3,137,432		11
				12
				13
				14
				15
		10,000		16
		3,222,139		17
398,171		-3,997,962		18
				19
398,171		-765,823		20
				21
				22
		1,200		23
		31,136,050		24
-81,879		-25,568,190		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
-81,879		29,887,236		34
				35
				36
		25,978,750		37
-49,012		-18,295,162		38
				39
-49,012		7,683,588		40
				41
1,191,524		40,152,618		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	02/24/2016	End of 2015/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
		-863,584		2
1,016,962		863,584		3
				4
1,016,962				5
				6
				7
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				9
				10
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				37
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				39
				40
				41
1,191,524		40,152,618		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)	1,335,700	1,004,654	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)	81,696,352	83,875,275	ALL
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	108,564,932	110,797,229	ALL
8	Transmission Plant (Estimated)	15,636,558	19,026,480	ALL
9	Distribution Plant (Estimated)	98,541,497	98,859,942	ALL
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	304,439,339	312,558,926	
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)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	305,775,039	313,563,580	

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	88,301.00		13,860.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Allowances Used	14.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	88,287.00		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)		22		
45	Gains		22		
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	02/24/2016	End of 2015/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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
13,860.00		13,860.00		360,360.00		490,241.00		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
						14.00		20
								21
								22
								23
								24
								25
								26
								27
								28
13,860.00		13,860.00		374,220.00		504,087.00		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
					6		28	44
					6		28	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 $265,891,383 in CO2 allowances issued by the California Air Resources Board (CARB) and $1,050,000 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	02/24/2016	End of 2015/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)	2016 No. (d)	2016 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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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.

2017		2018		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2	NONE					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	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) 02/24/2016	Year/Period of Report End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22	NONE					
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

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 foot notes)	4,084,113	186	(4,076,527)	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 foot notes)	767,572	186	(803,799)	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 12/31/2014	COSTS INCURRED PERIOD ENDED 12/31/2015	REIMBURSEMENTS RECEIVED PERIOD ENDED 12/31/2015	NET ACTIVITY PERIOD ENDED 12/31/2015	BALANCE 12/31/2015
9715072	WL -(SIS)Interconnection Merced Irr Dist	11,510.42	(11,510.42)		(11,510.42)	
9718826	WL - BART Gridley 2 Solar -- SIS	4,730.42				4,730.42
9719582	WG Gradient Resources Project SIS	22,883.99				22,883.99
9719800	WAPA O'Neill Substation - System Impact	4,623.39	(4,623.39)		(4,623.39)	
9719900	WG - BURNS&MCDONNELL-Cluster work	(415.42)	32,816.78	32,816.78		32,401.36
9720361	WG - CLUSTER 5 PROJECTS - PHASE 2	20,003.94	(12,996.06)	(12,996.06)		7,007.88
9720841	Port of Stockton Solar- System Impact S	(5,914.43)				(5,914.43)
9721302	WG Stockton Gen Q172 Q248 - Restudy	41,250.93	(41,250.93)	4,483.01	(45,733.94)	
9721301	WG Green Ridge - Repowering Study	30,073.18	(30,073.18)	767.82	(30,841.00)	
9721940	West Stanislaus ID Facility Study	(45,116.09)				(45,116.09)
9722101	WG-Restudy-Q529A - Wellhead Renew Fresno	32,112.84	(32,112.84)		(32,112.84)	
9722102	WG -ISP - Wellhead Power Gates	4,777.51	(4,777.51)	39,886.28	(44,663.79)	
9722120	WG -Repowering Study -Summit Wind	13,559.72	(13,559.72)	35,123.78	(48,683.50)	
9722121	WG - 2014 Reassessment	132,982.13	(132,982.13)	(1,833.63)	(131,148.50)	
9722123	CDWR DHCCP System Impact Study	141.32	(141.32)	(141.32)		
9722202	WG - C6 - Cluster 6 Phase 2	484,323.11	(459,889.49)	(76,966.49)	(382,923.00)	24,433.62
9722300	WG - Repowering - EDF Patterson Pass	19,188.46	(19,188.46)		(19,188.46)	
9722822	WG Fast Track - Westlands Solar Farm PV2	5,921.67	(5,921.67)	134.46	(6,056.13)	
9722840	WG - C7P1 - Cluster 7 Phase 1	548,715.98	(548,715.99)	189,160.91	(737,876.90)	(0.01)
9722880	WG - MMA - Q705 - Frontier Blackwell	485.43	(485.43)	(485.43)		
9722960	WG - AC6P2 - Q955 - Algonquin Sanger 2	3,646.71	(3,646.71)		(3,646.71)	
9723361	WG - MMA - Q472 - Blue Lake Power	131.77	(131.77)	(131.77)		
9723440	WG - MMA - Q965 - Luis Solar	800.90	(800.90)	10,613.62	(11,414.52)	
9723600	CDWR BDCP-CM1 System Impact Study	(21,055.06)	27,105.40	64,707.82	(37,602.42)	6,050.34
9723580	WG - MMA - Q829 - Panoche Valley Solar	2,798.46	(2,798.46)	1,362.26	(4,160.72)	
9723640	WG - MMA - Q687 - Columbia Solar II	855.33	(855.33)	364.46	(1,219.79)	
9723622	WG - MMA - Q877 - California Flats Solar	4,111.33	(4,111.33)	7,957.52	(12,068.85)	
9723700	WG - MMA - Q550 CAL SP V	1,638.45	(1,638.45)		(1,638.45)	
9723860	WG - 2015 Reassessment	5,889.13	(5,889.20)	248,959.57	(254,848.77)	(0.07)
9723921	WG - MMA - Q581 - Henrietta Solar	1,500.40	(1,500.40)	6,641.38	(8,141.78)	
9723961	WG - MMA - Q648 - Oro Loma IV	1,514.22	(1,514.22)	67.23	(1,581.45)	
9724040	KMPUD Load Interconnection Study	3,153.70	(51,860.70)	58,639.30	(110,500.00)	(48,707.00)
9724060	WG-MMA-Q557-White River West - Storage	2,700.24	25,132.92	25,132.92		27,833.16
9724100	WG-MMA-Q653F-PVUSA CleanPath Solar	997.92	(997.92)	639.35	(1,637.27)	
9724222	WG - MMA - Q620 - Maricopa West Solar PV	527.12	(527.12)	3,464.00	(3,991.12)	

9724281	WG - ISP - WGP Geysers		34,631.86	34,631.86		34,631.86
9724300	Ntwrk Eval for Calpine 115kV Geysers Gen		(17,125.55)	52,874.45	(70,000.00)	(17,125.55)
9724301	MercedID Plan B System Impact Study		11,545.69	41,545.69	(30,000.00)	11,545.69
9724360	WG-MMA-Q607-North Star Solar 1			5,311.82	(5,311.82)	
9724401	WG - Q472 Post COD Modification		14,449.37	14,449.37		14,449.37
9724460	WG - ISP - Avenal Power Plant - PV plus			3,985.47	(3,985.47)	
9724480	WG-MMA#Q558#Corcoran 2			5,924.35	(5,924.35)	
9724481	WG-MMA# Q482-Atwell West			6,121.31	(6,121.31)	
9724483	WG-MMA# Q625# EE K Solar 1			2,667.87	(2,667.87)	
9724560	WG ISP Woodland Battery		54,918.00	54,918.00		54,918.00
9724561	WG Fast Track Sand Hill Wind			9,573.66	(9,573.66)	
9724640	WG - ISP - Morro Bay Wave Energy			11,962.66	(11,962.66)	
9724722	WG - MMW - Q775 - Twisselman 1			6,083.43	(6,083.43)	
9724820	WG - MMA # Q1038 # Pandora Solar		2,342.33	2,342.33		2,342.33
9724880	WG - C7P2 - Cluster 7 Phase 2		425,953.36	425,953.36		425,953.36
9724960	WG - C8 - SM - WGP Geysers		6,848.14	6,848.14		6,848.14
9724961	WG - C8 - SM - New Kearney Energy Park		(202.78)	5,066.13	(5,268.91)	(202.78)
9724923	WG - C8P1 - Cluster 8 Phase 1		679,371.37	679,371.37		679,371.37
9724980	WG - MMA - Q744 Redwood Solar			6,197.41	(6,197.41)	
9724929	WG - MMA - Q645A-Sirius Solar-COD Change			867.53	(867.53)	
9724930	WG - C8 - SM - Midtown Park ES		(99.49)	1,531.69	(1,631.18)	(99.49)
9725006	WG - C8 - SM - Alpaugh3BESS		(207.92)	3,684.20	(3,892.12)	(207.92)
9725007	WG - C8 - SM - AmericanKings2		(207.92)	3,856.39	(4,064.31)	(207.92)
9725008	WG - C8 - SM - AtwellWestBESS		(207.91)	3,645.30	(3,853.21)	(207.91)
9725009	WG - C8 - SM - Britain		(207.91)	3,760.78	(3,968.69)	(207.91)
9725010	WG - C8 - SM - CabrilloWind		(61.62)	4,117.39	(4,179.01)	(61.62)
9725011	WG - C8 - SM - Corcoran2BESS		(385.96)	3,467.25	(3,853.21)	(385.96)
9725012	WG - C8 - SM # Trafalgar		(194.21)	4,279.37	(4,473.58)	(194.21)
9725013	WG - C8 - SM # Troy		(207.91)	3,856.31	(4,064.22)	(207.91)
9725014	WG - C8 - SM - WhiteRiverBESS		(207.91)	3,588.65	(3,796.56)	(207.91)
9725000	WG - C8 - SM - Carneras Solar 1		(207.91)	3,756.49	(3,964.40)	(207.91)
9725001	WG - C8 - SM - Gale Solar 1		(16.16)	3,948.24	(3,964.40)	(16.16)
9725002	WG - C8 - SM - Quail Creek Solar 1		(207.91)	3,708.04	(3,915.95)	(207.91)
9725003	WG - C8 - SM - Seneca Solar 1		(207.91)	3,845.48	(4,053.39)	(207.91)
9725083	WG - C8 - SM -WestlandsAlmond		(167.47)	3,264.32	(3,431.79)	(167.47)
9725084	WG - C8 - SM -WestlandsApricot		(194.21)	4,146.70	(4,340.91)	(194.21)
9725085	WG - C8 - SM -WestlandsArtichoke		(194.21)	3,110.00	(3,304.21)	(194.21)
9725086	WG - C8 - SM -AlamoSprings		644.17	3,392.04	(2,747.87)	644.17
9725087	WG - C8 - SM -AlgosoES					

FOOTNOTE DATA

			644.17	4,015.88	(3,371.71)	644.17
9725088	WG - C8 - SM #Bridgehead		(335.82)	5,507.03	(5,842.85)	(335.82)
9725089	WG - C8 - SM #Brisbane		15.66	4,149.05	(4,133.39)	15.66
9725090	WG - C8 - SM -CentralValleyProject		171.70	4,183.10	(4,011.40)	171.70
9725091	WG - C8 - SM -CSICENTRAL40		(335.82)	2,227.43	(2,563.25)	(335.82)
9725092	WG - C8 - SM -DosAmigosSolar		(335.82)	4,032.51	(4,368.33)	(335.82)
9725093	WG - C8 - SM -FirebaughPanocheBESS		(335.82)	4,192.89	(4,528.71)	(335.82)
9725095	WG - C8 - SM -FresnoSolar1		337.36	3,984.77	(3,647.41)	337.36
9725096	WG - C8 - SM -GoldenEyeEnergyStorageCent		(335.82)	3,162.03	(3,497.85)	(335.82)
9725097	WG - C8 - SM -MolinoES		(335.82)	3,210.95	(3,546.77)	(335.82)
9725098	WG - C8 - SM -Montezuma 3		(335.82)	2,510.03	(2,845.85)	(335.82)
9725099	WG - C8 - SM -NicolausStorage		(335.82)	2,605.65	(2,941.47)	(335.82)
9725100	WG - C8 - SM -NorthCentralValley		(335.82)	3,433.09	(3,768.91)	(335.82)
9725101	WG - C8 - SM -OldKearneyES		30.54	4,357.18	(4,326.64)	30.54
9725102	WG - C8 - SM -Periwinkle		644.18	4,316.69	(3,672.51)	644.18
9725103	WG - C8 - SM -PointArenaES		644.18	4,439.58	(3,795.40)	644.18
9725104	WG - C8 - SM -SantaMariaEnergyReliabilit		55.04	3,258.87	(3,203.83)	55.04
9725105	WG - C8 - SM -ShingleSpringsES		(335.82)	4,075.12	(4,410.94)	(335.82)
9725106	WG - C8 - SM -WestlandsSolarBlue		(207.91)	3,920.28	(4,128.19)	(207.91)
9725107	WG - C8 - SM #WheelerIndigo		(335.82)	4,281.29	(4,617.11)	(335.82)
9725108	WG - C8 - SM -WhiteWolfSolar		(335.82)	3,797.03	(4,132.85)	(335.82)
9725040	WG - C8 - SM - AnchoCreekSolar		(207.92)	3,681.21	(3,889.13)	(207.92)
9725041	WG - C8 - SM # BasketRidgeSolar		(251.08)	3,548.44	(3,799.52)	(251.08)
9725042	WG - C8 - SM # BearCanyonEnergyStorage		644.18	4,456.76	(3,812.58)	644.18
9725043	WG - C8 - SM - KimberlinaSolar		664.18	3,336.76	(2,672.58)	664.18
9725044	WG - C8 - SM - LunaValleySolar		(335.82)	2,893.13	(3,228.95)	(335.82)
9725045	WG - C8 - SM - MountVernonSolar		337.36	3,316.76	(2,979.40)	337.36
9725046	WG - C8 - SM - OvejaSolarFarm		644.18	3,892.79	(3,248.61)	644.18
9725047	WG - C8 - SM - WhiterockSolar		644.18	3,720.11	(3,075.93)	644.18
9725048	WG - MMA # Q526 # Westside Solar Farm			672.26	(672.26)	
9725049	WG - C8 - SM -AquamarineWestside		(207.92)	3,519.93	(3,727.85)	(207.92)
9725050	WG - C8 - SM -BeltranSolar_Updated		(335.82)	3,714.09	(4,049.91)	(335.82)
9725051	WG - C8 - SM -CornwallEnergyStorage		(335.82)	4,055.97	(4,391.79)	(335.82)
9725052	WG - C8 - SM #Creek		1,000.00	2,210.51	(1,210.51)	1,000.00
9725053	WG - C8 - SM -HenriettaEnergyStorage		(101.51)	4,263.92	(4,365.43)	(101.51)
9725054	WG - C8 - SM -MaricopaWestSolarPV3		193.01	3,062.10	(2,869.09)	193.01
9725055	WG - C8 - SM #McCloudWind		(335.82)	2,477.19	(2,813.01)	(335.82)
9725056	WG - C8 - SM -MoonPrism_2		(86.12)	3,392.03	(3,478.15)	(86.12)
9725057	WG - C8 - SM #OaklandES		(335.82)	4,534.58	(4,870.40)	(335.82)

9725058	WG - C8 - SM #PittsburgEnergyStorage		(335.82)	3,679.97	(4,015.79)	(335.82)
9725059	WG - C8 - SM #Ripon		(335.82)	2,534.40	(2,870.22)	(335.82)
9725060	WG - C8 - SM - Sand Hill 2		(335.82)	4,485.38	(4,821.20)	(335.82)
9725061	WG - C8 - SM #Scarlett		361.86	4,834.24	(4,472.38)	361.86
9725063	WG - C8 - SM #Slate		(267.42)	4,172.25	(4,439.67)	(267.42)
9725064	WG - C8 - SM #UltrapowerChineseStation		(335.82)	3,839.14	(4,174.96)	(335.82)
9725120	WG - C8 - SM -ChestnutWestside		(309.20)	2,961.84	(3,271.04)	(309.20)
9725121	WG - C8 - SM -CooleyLandingBESS		(332.34)	4,185.53	(4,517.87)	(332.34)
9725122	WG - C8 # SM -LittleBear3		(335.82)	3,193.13	(3,528.95)	(335.82)
9725123	WG - C8 # SM -LittleBear4		(335.82)	3,443.27	(3,779.09)	(335.82)
9725124	WG # post-COD mp # Q378# LECEFE		26,948.69	26,948.69		26,948.69
9725160	WG - C8 - SM - Geysers Unit 11 Reconnect		(335.82)	2,873.68	(3,209.50)	(335.82)
9725140	LID SIS Restudy		(10,808.03)	4,191.97	(15,000.00)	(10,808.03)
9725202	WG - MMA # Q612# ThreeRocks		3,980.96	3,980.96		3,980.96
9725221	WG - MMA # Q687# ColumbiaSolar			403.36	(403.36)	
9725260	WG - C8 - SM Primrose Engy Storage Cntr		(527.57)	2,076.72	(2,604.29)	(527.57)
9725320	WG -MMA # Q825#PatriotSolarB			1,394.05	(1,394.05)	
9725321	WG -MMA # Q824#PatriotSolarA			1,528.51	(1,528.51)	
9725844	CDWR BDCP Phase 2 sudy		6,912.31	46,573.70	(39,661.39)	6,912.31
9725845	SVP PST Re-study		(20,000.00)		(20,000.00)	(20,000.00)
9725921	WG Fast Track - Campbell Solar 1		1,210.07	1,210.07		1,210.07
9725902	WG - MMA - Q272 - American Kings Solar		2,802.33	2,802.33		2,802.33
9725922	WG-MMA-Q709-Golden Hills 2,GR Repower		6,068.95	6,068.95		6,068.95
9725962	WG - MMA - Q644 - Chowchilla Solar		2,954.53	2,954.53		2,954.53
9726060	WG - MMA - Q356 - Cuyama Solar -COD Chg			555.34	(555.34)	
9726062	Q900 Rio Bravo Solar 1 COD/Inverter Cha		2,967.23	2,967.23		2,967.23
9726063	Q901 Wildwood Solar II COD/Inverter Cha		2,503.06	2,503.06		2,503.06
9726064	Q972 Rio Bravo Solar 2 COD/Inverter Ch		2,967.23	2,967.23		2,967.23
9726123	WG ISP q1092 Wellhead Gates Fac Stdy		5,051.95	5,051.95		5,051.95
9726101	WG MMA Q720 and Q1002 Lassen Lodge CODCH		1,062.80	1,062.80		1,062.80
9726102	Travis AFB Feasibility Study		(11,369.80)	3,630.20	(15,000.00)	(11,369.80)
9726131	WG - MMA # Q529-Freshwater		4,546.77	4,546.77		4,546.77
9726342	WG - MMA # Q526-Westside		767.81	767.81		767.81
9726343	WG - MMA # Q532- WhitneyPoint		767.81	767.81		767.81
9726381	WG - MMA # Q678- Burford		134.46	134.46		134.46
9726382	WG - MMA # Q539- FrontierSolar		134.46	134.46		134.46
9726383	WG - MMA # Q877- CaliforniaFlats		672.26	672.26		672.26
9707780	CP-Martin 115/60 kV Upgrade Project		486.01	486.01		486.01
9712247	WL-Red Bluff 6-MW Reclamation Pump Plant					

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

		18,877.08	(18,877.08)	(18,877.08)		
9713955	WL - Tesla Tracy 230kV Line 1 Reloc-FAS	13,215.50	(13,215.50)		(13,215.50)	
9715022	WL - WAPA Red Bluff PP-IFAS	9,458.99	(25,248.20)	(25,248.20)		(15,789.21)
9715140	WG - Rough & Ready Solar - SIS	(15,518.85)				(15,518.85)
9715781	WL - DOE Labs LBNL 2nd Capmus-SIS	51,893.73	(51,893.73)		(51,893.73)	
9716660	WL-LBNL City of Richmond-SKS	1,157.12	(1,157.12)		(1,157.12)	
9717162	WL - LBNL DOE Capacity Increase-SIS	8,050.00	(8,050.00)		(8,050.00)	
9717186	WL - SVP Phase-Shifting Trans Study	39,978.01	3,742.76	3,742.76		43,720.77
9719120	Merced ID Facility Study	35,285.68	(35,285.68)		(35,285.68)	
9720462	Lathrop Irrigation District Load Study	(9,197.93)	9,197.93	761.94	8,435.99	
9720641	Merced ID Interconnection System Study	12,174.09	(12,174.09)		(12,174.09)	
9722206	Trans Bay Cable Quick Start Study	(30,825.36)	4,058.59	4,058.59		(26,766.77)
9717187	WL - CA HiSpeed Train Interconnect Study	302,968.31	253,507.21	1,732,658.92	(1,479,151.71)	556,475.52
9714755	WL - KMPUD-IFAS	88,553.10	(25,000.00)		(25,000.00)	63,553.10
	Transmission Total	**1,861,118.59**	**7,585.53**	**4,084,112.60**	**(4,076,527.07)**	**1,868,704.12**

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

Order	Order Description	BALANCE 12/31/2014	COSTS INCURRED PERIOD ENDED 12/31/2015	REIMBURSEMENTS RECEIVED PERIOD ENDED 12/31/2015	NET ACTIVITY PERIOD ENDED 12/31/2015	BALANCE 12/31/2015
9712880	BIG CREEK HYDRO (Protection/reliability)	(1,723.40)	1,723.40	1,723.40		
9713622	BIG CREEK HYDRO (Protection/reliability)	(3.00)	3.00	3.00		
9718222	Eagle Energy-Bakersfield 240(a) F. Track	1,000.00	(1,000.00)	(1,000.00)		
9720265	WDT-ZWEDC Phase 1, CL6 Deliv Assess	3,747.10	31,910.25	31,910.25		35,657.35
9720266	WDT-OakLeafSolar-Reedly,CL6 Deliv Assess	3,747.10	31,910.25	31,910.25		35,657.35
9720267	WDT - G18 Solar 1, CL6 Deliv Assess	28,180.76	(28,180.76)		(28,180.76)	
9720269	WDT - Oak Leaf Solar X, CL6 Deliv Assess	3,747.10	31,910.25	31,910.25		35,657.35
9721383	MRWMD LFG Pwr Plant 2 (0780-RD) Det Sty	(3,602.68)	3,602.68	1,924.26	1,678.42	
9722203	Shasta Renewable LLC- Independent Study	(40,846.67)	40,846.67	2,199.15	38,647.52	
9722340	R21 - 2076 Mass - Detailed Study	1,646.98	4,468.54	4,468.54		6,115.52
9722681	WDT - Redwood Indep. Study Process	1,661.64	(1,661.64)		(1,661.64)	
9722764	R21-Apple Computer (1 of 2) Detailed Sty	(43,742.61)	43,742.61	80.48	43,662.13	
9722765	R21-Apple Computer (2 of 2) Detailed Sty	(38,560.74)	38,560.74	4,184.74	34,376.00	
9722881	R21 - 2064 Rogers - Detailed Study	(4,188.61)	4,188.61		4,188.61	
9723060	WDT - Binford Road Storage - Fast Track	4,037.51	(4,037.51)		(4,037.51)	
9723163	R21 - SRI International WPA	6,085.09	(6,085.09)	1,875.60	(7,960.69)	
9723200	GrnRdge Pwr Wireless DTT Option: Scoping	52,515.18	(52,515.18)		(52,515.18)	
9723260	R21 - Dignity Health - Detailed Study	1,209.16	(1,209.16)		(1,209.16)	
9723241	R21 ClarksburgWindTurbine (0936-RD)DetSt	(356.85)	356.85		356.85	
9723302	WDT - Lemoore 3 JC - Independent Study	3,284.26	(3,284.26)		(3,284.26)	
9723320	WDT-Energy 2001-Ind Study (Restudy)	(8,034.66)	8,034.66	8,034.66		
9723321	WDT Freethy Industrial Park Facility Sty					

FOOTNOTE DATA

		(9,789.65)	6,996.74	6,996.74		(2,792.91)
9723323	WDT - Sirius Solar - Fast Track Study	(705.33)	705.33	705.33		
9723325	R21-SWPCP-Close Transition Scheme Review	(5,000.00)	5,000.00		5,000.00	
9723326	WDT - Binford Storage - Supplemental Rev	2,769.58	(2,769.58)		(2,769.58)	
9723328	WDT-Maricopa East Solar PV 2-Ind Study	(52,064.48)	20,377.24	19,577.24	800.00	(31,687.24)
9723380	WDT- 35.325 - 9th Ave. Fast Track Study	650.69	(650.69)		(650.69)	
9723382	WDT- 45.1301 Leavenworth Fast Track Sty	624.69	(624.69)		(624.69)	
9723384	WDT- 47.267-287 Green Fast Track Study	482.69	(482.69)		(482.69)	
9723387	WDT- 50.2898 Jackson Fast Track Study	151.35	(151.35)		(151.35)	
9723388	WDT- Peterson Rd Solar 1 - Indepen Study	1,211.99	(1,211.99)	1,982.23	(3,194.22)	
9723460	WDT - Eagle Solar - Supplemental Review	(227.88)	227.88	824.68	(596.80)	
9723423	WDT - Bakersfield 1- System Impact Study	(51,991.89)	991.12	991.12		(51,000.77)
9723500	WDT - Oro Loma 1 FIT - Fast Track Study	1,818.78	(1,818.78)		(1,818.78)	
9723520	WDT - 54.78 Buchanan - Fast Track Study	(658.00)	2,000.49	2,000.49		1,342.49
9723521	WDT - 56.2677 Larkin - Fast Track Study	(658.00)	2,270.35	2,270.35		1,612.35
9723522	WDT - 58.500 Stanyan - Fast Track Study	(658.00)	658.00	1,986.01	(1,328.01)	
9723523	WDT - 7.1660 Bay - Fast Track Study	(610.67)	610.67	2,315.14	(1,704.47)	
9723524	WDT - 8.1840 Clay - Fast Track Study	(610.67)	610.67	2,383.86	(1,773.19)	
9723525	WDT - 9.2363 Van Ness - Fast Track Study	(705.34)	705.34	705.34		
9723526	WDT - 19.411 15th Ave - Fast Track Study	(610.67)	610.67	2,799.94	(2,189.27)	
9723527	WDT - 5.915 Pierce - Fast Track Study	(610.67)	2,462.04	2,462.04		1,851.37
9723528	WDT - 6.106 Sanchez - Fast Track Study	(610.67)	610.67	1,986.01	(1,375.34)	
9723529	WDT - 10.1690 Northpoint Fast Track Sty	(610.67)	610.67	676.48	(65.81)	
9723531	WDT - 11.2500 Van Ness - Fast Track Stdy	(516.00)	2,124.38	2,124.38		1,608.38
9723532	WDT - 16.2975 Van Ness - Fast Track Stdy	(610.67)	610.67	980.37	(369.70)	
9723533	WDT - 17.1260 Broadway - Fast Track Stdy	(610.67)	610.67	1,215.54	(604.87)	
9723534	WDT - 18.3210 Gough - Fast Track Study	(563.33)	618.50	618.50		55.17
9723535	WDT - 21.3715 California Fast Track Stdy	(658.00)	745.21	745.21		87.21
9723536	WDT - 22.1500_1514 Geneva Fast Track Sty	(658.00)	2,172.64	2,172.64		1,514.64
9723537	WDT - 23.500-506 Bartlett Fast Track Sty	(658.00)	2,172.65	2,172.65		1,514.65
9723538	WDT - 24.1547 Clay- Fast Track Study	(658.00)	1,897.74	1,897.74		1,239.74
9723539	WDT - 26.1440 Sutter - Fast Track Study	(658.00)	2,378.81	2,378.81		1,720.81
9723540	WDT Natoma Storage System Impact Study	(8,105.30)	8,962.63	8,962.63		857.33
9723541	WDT El Dorado Storage System Impact Stdy	(8,105.30)	8,430.36	8,430.36		325.06
9723542	WDT Golden Hill Storage System Impct Sty	(8,105.30)	6,610.54	6,610.54		(1,494.76)
9723567	WDT - 33.520 Buchanan - Fast Track Study	(658.01)	2,216.15	2,216.15		1,558.14
9723560	WDT - 57.1870 Pacific - Fast Track Study	(658.01)	1,980.98	1,980.98		1,322.97
9723561	WDT 27.1656 Leavenworth - Fast Track Sty	(658.01)	658.01	658.01		
9723562	WDT 28.2038 Divisadero - Fast Track Sty	(658.01)	658.01	676.48	(18.47)	

9723563	WDT - 1.400 Duboce - Fast Track Sty	(658.01)	2,324.59	2,324.59		1,666.58
9723564	WDT - 3.100 Broderick - Fast Track Sty	(658.01)	658.01	1,284.26	(626.25)	
9723565	WDT - 25.2238 Hyde - Fast Track Sty	(658.01)	1,255.26	1,255.26		597.25
9723566	WDT - 32.737 Pine - Fast Track Sty	47.33	(47.33)	(47.33)		
9723568	WDT 34.1855 10th Ave - Fast Track Study	(705.34)	1,146.81	1,146.81		441.47
9723569	WDT 36.4540 Californiia Fast Track Study	(705.34)	705.34	1,009.37	(304.03)	
9723570	WDT- 37.1355 Lombard - Fast Track Study	(705.34)	1,373.22	1,373.22		667.88
9723571	WDT- 38.240 Cumberland Fast Track Study	(705.34)	705.34	705.34		
9723572	WDT- 41.311 Corbett - Fast Track Study	(705.34)	705.34	705.34		
9723581	WDT- Spondee Solar II LLC Fast Track Sty	4,037.53	(4,037.53)	2,227.07	(6,264.60)	
9723662	WDT- Sirius 10 - Fast Track Study	(705.33)	332.88	332.88		(372.45)
9723660	WDT - Lemoore 1 HN - System Impact Study	(2,495.59)	2,495.59	6,016.75	(3,521.16)	
9723661	WDT - Lemoore 2 HN - System Impact Study	(8,932.19)	8,932.19		8,932.19	
9723840	WDT - Sher Solar - Fast Track Study	(705.33)	705.33	705.33		
9723880	WDT - CLK 240 - Fast Track Study	314.71	(314.71)	1,490.44	(1,805.15)	
9723881	WDT Black Diamond Energy Storage F Track	1,576.06	(1,576.06)	1,884.52	(3,460.58)	
9723920	WDT - Sher Solar Phase 2 Fast Track Sty	(658.00)	658.00	658.00		
9723900	WDT - Lakeview Dairy Biogas Indep. Study	(10,000.00)	7,758.78	7,758.78		(2,241.22)
9723901	WDT - West-Star Dairy Biogas Indep Study	(10,000.00)	9,058.04	9,058.04		(941.96)
9723903	WDT - Binford Storage System Impact Sty	(10,000.00)	10,000.00	18,271.93	(8,271.93)	
9724001	WDT - Spondee Solar II, LLC Supp. Review	(2,121.31)	2,121.31	2,640.48	(519.17)	
9724002	WDT - Sher Solar - Supplemental Review	(928.65)	928.65	716.23	212.42	
9724181	R21 2076 Maas - Facilities Study		(15,000.00)		(15,000.00)	(15,000.00)
9724180	0946-WD Peterson Rd Solar 1 Facility Sty	(15,000.00)	15,000.00	12,299.31	2,700.69	
9724160	R21 City of San Jose WPCP - Detailed Sty		230.00	30,530.05	(30,300.05)	230.00
9724221	WDT - Chevron 2MW Fast Track Study	(800.00)	800.00	5,154.82	(4,354.82)	
9724258	WDT - DRES Quarry 2.1 Fast Track Study	(800.00)	800.00	1,714.85	(914.85)	
9724282	1078-WD - CLK 240 - Supplemental Review		(214.59)	2,285.41	(2,500.00)	(214.59)
9724321	WDT Shingle Springs Energy Fast Track			800.00	(800.00)	
9724320	R21 Genentech Inc. Non Exp Detailed Sty		(41,118.43)	16,881.57	(58,000.00)	(41,118.43)
9724361	R21 NEMMT - City of Bakersfield Restudy		(1,005.47)	3,994.53	(5,000.00)	(1,005.47)
9724381	WDT - WGE-1 Fast Track Study			3,808.78	(3,808.78)	
9724402	R21 Utilastore Shingle Springs 1 Det Sty			870.68	(870.68)	
9724403	WDT-50001 SCWA North&South Ponds Fst Trk		(31,526.03)	25,473.97	(57,000.00)	(31,526.03)
9724404	WDT-50002 SCWA Ponds 1 & 2 Fast Track			1,588.15	(1,588.15)	
9724405	WDT-50004 SCWA R5 Pond Fast Track Study		817.14	1,617.14	(800.00)	817.14
9724420	WDT - LeMoore 2 HN - Fast Track Study			5,859.58	(5,859.58)	
9724421	WDT - Chevron 8.5 Independent Study		(45,289.72)	13,710.28	(59,000.00)	(45,289.72)
9724422	R21 Blue Mountain Electric - Detail Sty					

FOOTNOTE DATA

				5,709.19	(5,709.19)	
9724423	R21 North Fork Community Power - Det Sty			7,760.43	(7,760.43)	
9724424	TO - COO - CalRenew-1 Solar DTT			15,546.13	(15,546.13)	
9724441	WDT - Dres Quarry 2.1 - Supplemental Rev		(835.61)	1,664.39	(2,500.00)	(835.61)
9724442	WDT - Shingle Springs - Fast Track Study		676.49	676.49		676.49
9724500	WDT Sonoma Valley PV 100kW - Fast Track		1,313.26	1,313.26		1,313.26
9724521	WDT-Golden Valley Energy Stor Indep Sty			2,468.04	(2,468.04)	
9724540	McFarland Solar 0157WD System Impact Sty		(2,304.71)	7,695.29	(10,000.00)	(2,304.71)
9724541	Chevron 2MW 1122-WD Supplemental Review		7,136.29	9,636.29	(2,500.00)	7,136.29
9724580	WDT - Morgan Hill BESS - Fast Track Sty		571.24	1,371.24	(800.00)	571.24
9724660	WDT New Slab Creek Powerhouse Fast Track		4,354.34	14,354.34	(10,000.00)	4,354.34
9724661	WDT - Peacock Phase II Fast Track Study		774.21	774.21		774.21
9724662	WDT Sirius Solar Phase II Fast Track Sty		936.89	936.89		936.89
9724683	TO-Green Ridge Repowering Facilities Sty		7,404.53	7,404.53		7,404.53
9724742	WDT- Porter B Energy Storage - Indep Sty		(7,310.50)	2,689.50	(10,000.00)	(7,310.50)
9724743	WDT- Madera 1 - Fast Track Study		303.89	303.89		303.89
9724700	WDT-Burdell Solar Energy Fast Track Sty		4,630.23	4,630.23		4,630.23
9724701	WDT-Golden Valley Energy Storage_Cluster			6,322.55	(6,322.55)	
9724704	WDT- CE&S Dairy Biogas - Independent Sty		(5,245.59)	4,754.41	(10,000.00)	(5,245.59)
9724740	50002 SCWA Ponds 1 & 2 1149-WD Supp Rev		195.23	2,695.23	(2,500.00)	195.23
9724741	50004 SCWA R5 Pond 1150-WD Supp Rev		(177.37)	2,322.63	(2,500.00)	(177.37)
9724702	WDT - Templeton A Energy Storage- ISP			1,609.92	(1,609.92)	
9724703	WDT - Templeton B Energy Storage- ISP		(6,139.59)	3,860.41	(10,000.00)	(6,139.59)
9724780	WDT - Porter Solar - Independent Study		(6,638.39)	3,361.61	(10,000.00)	(6,638.39)
9724900	WDT - Buck Institute Cluster Study		(45,845.27)	5,154.73	(51,000.00)	(45,845.27)
9724901	WDT - Peacock Phase II - Independent Sty		(2,400.03)	7,599.97	(10,000.00)	(2,400.03)
9724926	R21 Scheid Vineyards Corp Detailed Study		464.17	464.17		464.17
9724927	R21 Wal-Mart Stores Inc. Detailed Study		0.01	2,343.17	(2,343.16)	0.01
9724920	WDT Bakersfield Industrial 1(A) Fast Trk		6,909.90	6,909.90		6,909.90
9724921	WDT Bakersfield Industrial 1(B) Fast Trk			4,130.91	(4,130.91)	
9724922	WDT - Manteca Land 1 Fast Track Study		745.22	745.22		745.22
9724931	WDT Delano Land 1 - Fast Track Study		8,589.32	8,589.32		8,589.32
9724932	WDT Kern County Industrial 1 - Indep Sty		27,390.32	37,390.32	(10,000.00)	27,390.32
9725005	WDT Shingle Springs Energy Storage Indep			1,228.03	(1,228.03)	
9725015	WDT Madera 1 - Supplemental Review		172.83	172.83		172.83
9725016	WDT Manteca Land 1- Supplemental Review			1,910.29	(1,910.29)	
9725020	R21: City of Soledad - ENOS 202645 - DIS			4,084.58	(4,084.58)	
9725021	R21: Cemex Constr - ENOS 202656 - DIS			268.90	(268.90)	
9725022	R21: Taylor Farms - NEMMT - DIS			3,136.86	(3,136.86)	

9725080	0963-WD Binford Rd Storage Facility Sty		(12,800.88)	2,199.12	(15,000.00)	(12,800.88)
9725081	1207-WD Bakersfield Indus 1 (A) Supp Rev			3,848.50	(3,848.50)	
9725082	1208-WD Bakersfield Indus 1 (B) Supp Rev		1,649.36	6,597.44	(4,948.08)	1,649.36
9725065	WDT - Porter B Energy Storage Deliv Sty		(1,053.75)	8,946.25	(10,000.00)	(1,053.75)
9725066	WDT - Porter Solar Devlierability Study		(5,054.05)	4,945.95	(10,000.00)	(5,054.05)
9725069	WDT - Templeton B Energy Storage Del Sty		3,626.70	13,626.70	(10,000.00)	3,626.70
9725070	WDT - New Slab Creek Powerhouse Del Sty		8,246.78	8,246.78		8,246.78
9725071	R21 El Camino Irrig Dist Detailed Study			601.79	(601.79)	
9725180	WDT-Black Diamond Energy Storage-FastTrk		2,195.92	2,195.92		2,195.92
9725220	EID Powerhouse Post-COD Telecom Study		(6,407.71)	3,592.29	(10,000.00)	(6,407.71)
9725240	WDT - Delano Land Project - Supp Review		248.94	2,748.94	(2,500.00)	248.94
9725300	ConEdison Solar Post-COD Telecom Study		15,482.87	15,482.87		15,482.87
9725340	WDT-Sirius Solar Phase II 740kw Fast Trk		318.39	318.39		318.39
9725380	1221-WD Burdell Solar Energy - Supp Rev		3,229.78	5,729.78	(2,500.00)	3,229.78
9725760	WDT-Apex Energy-Madera 1-1.5MW-FastTrk		1,186.56	1,186.56		1,186.56
9725802	WDT-Apex Energy-Madera 1-1.0MW-FastTrk		441.34	441.34		441.34
9725820	1207-WD Bakersfield Indus 1 (A) SIS		(3,638.34)	6,361.66	(10,000.00)	(3,638.34)
9725841	WDT- Orange Cove 2 - Fast Track		6,546.97	6,546.97		6,546.97
9725842	R21 Apple Enos 147238 - Detailed Study		(7,496.91)	2,503.09	(10,000.00)	(7,496.91)
9725843	R21 Apple Enos 147273 - Detailed Study		(7,330.47)	2,669.53	(10,000.00)	(7,330.47)
9725880	1227WD Black Diamond Energy Stor Sup Rev		(275.32)	2,224.68	(2,500.00)	(275.32)
9725900	8.4 MW Frick Wind Repower Facilities Sty		3,687.06	13,687.06	(10,000.00)	3,687.06
9725901	2.99 MW Dyer Wind Repower Facilities Sty		651.34	10,651.34	(10,000.00)	651.34
9725963	WDT New Slab Creek Pwrhse Facilities Sty		(8,484.87)	6,515.13	(15,000.00)	(8,484.87)
9725960	WDT El Dorado Storage - Facilities Study		(12,870.71)	2,129.29	(15,000.00)	(12,870.71)
9726012	WDT - Peacock Phase II - Facility Study		(13,759.12)	1,240.88	(15,000.00)	(13,759.12)
9726013	WDT - 50003 SCWA R4 Fast Track Study		6,879.83	6,879.83		6,879.83
9726041	WDT - Sirius Solar Phase 2 Suppl. Review		437.93	2,937.93	(2,500.00)	437.93
9726044	1223-RD Indian Valley Hydro - Det. Study		(7,298.48)	2,701.52	(10,000.00)	(7,298.48)
9726040	R21 Genentech - Facilities Study		(11,519.87)	1,980.13	(13,500.00)	(11,519.87)
9726081	WDT Collins Small Bioenergy Indep Study		(8,578.12)	1,421.88	(10,000.00)	(8,578.12)
9726124	WDT - Madera 1 - 1.0 Supplemental Review		(1,019.63)	1,480.37	(2,500.00)	(1,019.63)
9726126	WDT - DRES Quarry 2 (09_2015) Fast Track		2,199.14	2,199.14		2,199.14
9726127	WDT - Camden 1 FIT 1 PV - Fast Track		911.65	911.65		911.65
9726125	GJ TeVelde Ranch Pacific Rim Detail. Sty		(9,500.68)	499.32	(10,000.00)	(9,500.68)
9726129	R21 193203 Sierra Nevada Brewing Det Sty		(1,833.56)	166.44	(2,000.00)	(1,833.56)
9726128	R21 Hanford Renewable Energy Detail Sty		(7,565.67)	2,434.33	(10,000.00)	(7,565.67)
9726130	WDT - McFarland Solar - Facilities Study		(15,000.00)		(15,000.00)	(15,000.00)
9726132	WDT - Castroville Energy Storage - ISP					

FOOTNOTE DATA

			(8,248.40)	1,751.60	(10,000.00)	(8,248.40)
9726180	R21-US Air Force Civil Engrs-Det Study		(69,300.95)	6,699.05	(76,000.00)	(69,300.95)
9726241	WDT - Camden 1 FIT 1, PV - Supp. Review		(922.59)	1,577.41	(2,500.00)	(922.59)
9726300	WDT Black Diamond Energy 11_2015 F Trk		929.93	929.93		929.93
9726360	WDT - Bellanave Dairy Biogas - Indep Sty		(9,187.30)	812.70	(10,000.00)	(9,187.30)
9726361	1252-WD 50003 SCWA R4 Pond Supp Review		(1,950.22)	549.78	(2,500.00)	(1,950.22)
9726400	0026-WD G2 Energy Ostrom Rd Replace Gen		(757.07)	242.93	(1,000.00)	(757.07)
9726421	1274-WD Black Diamond Energy - Suppl Rev		(2,500.00)		(2,500.00)	(2,500.00)
9726443	R21 Burney-Hat Creek Bio 12_15 Det. Stdy		(9,667.12)	332.88	(10,000.00)	(9,667.12)
	Distribution Total	**(243,820.27)**	**(36,227.07)**	**767,572.37**	**(803,799.44)**	**(280,047.34)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	Acc Amt - Plant RA Tax	(151,325,765)		405	3,520,572	-154,846,337
2	(amortization: 11 years)					
3	Accum Amort - URG Plant Reg Asset	3,520,575				3,520,575
4	(amortization: < 12 months)					
5	Accum Amort - URG Plant Reg Asset Non Current	(517,576,723)		405	43,335,000	-560,911,723
6	(amortization: 12 years)					
7	Balancing Account - Utility Generation	261,187,576	2,166,210,900	400	2,305,203,159	122,195,317
8	(amortization: < 12 months)					
9	BCA Charge Account	441,360	2,928,343	400	971,697	2,398,006
10	(amortization: <12 months)					
11	CA Alternate Rates for Energy Program-Electric	(13,662,403)	519,328,908	400	469,370,227	36,296,278
12	(amortization: < 12 months)					
13	CA Alternate Rates for Energy Program-Gas	(28,882,015)	120,214,605	400	116,926,420	-25,593,830
14	(amortization: < 12 months)					
15	CA Solar Initiative Thermal Program Memo Account	5,082,896	6,777,061	400	5,044,600	6,815,357
16	(amortization: < 12 months)					
17	Catastrophic Event Memorandum Account		52,516,000	182.3	26,258,000	26,258,000
18	(amortization: <12 months)					
19	CEE Incentive Electric Balancing Account	32,436,995	20,254,185	400	28,236,073	24,455,107
20	(amortization: < 12 months)					
21	CEE Incentive Gas Balancing Account	7,319,886	5,734,387	400	11,617,907	1,436,366
22	(amortization: < 12 months)					
23	Community Choice Aggr. Implem. Costs Balan. Acct.	4,018,610	5,864			4,024,474
24	(amortization: < 12 months)					
25	CORE BROKERAGE FEE	1,927,566	6,992,334	400	7,367,020	1,552,880
26	Amortization : < 12 MONTHS					
27	Core Fixed Cost Gas Balancing Account	565,952,810	2,279,601,894	400	2,352,747,708	492,806,996
28	(amortization: < 12 months)					
29	Core Gas Pipeline Safety Bal Acct	(35,214,850)	41,542,195	400	11,803,497	-5,476,152
30	(amortization: < 12 Months)					
31	Core Pipeline Demand Charge Account	32,027,284	515,145,673	400	536,152,898	11,020,059
32	(amortization: < 12 months)					
33	Customer Data Access B/A-Elec Rev	476,928	4,320,701	182.3	8,369,816	-3,572,187
34	(amortization: 3 years)					
35	Deferred Debit - Gas Reserves (Contra Balancing Ac	(205,970,627)	261,521,494	400	79,668,524	-24,117,657
36	(amortization: < 12 months)					
37	Demand Response Expenditures B/A (DREBA)	(4,963,989)	7,984,707	400	2,409,047	611,671
38	amortization: < 12 months					
39	Department of Energy Litigation Balancing Account	(114,009,160)	21,014,241	182.3	21,097,023	-114,091,942
40	(amortization: > 12 months)					
41	Diablo Canyon Seismic Studies Balancing Acct	41,203,083	6,762,106			47,965,189
42	(amortization: < 12 months)					
43	Distribution Revenue Adjustment Mechanism	344,207,852	5,048,465,608	400	5,012,326,637	380,346,823
44	TOTAL	7,687,225,400	25,738,018,587		24,758,332,308	8,666,911,679

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	DWR Power Charge Collection Balancing Account	38,879,973	82,486,356	400	129,203,514	-7,837,185
3	(amortization: < 12 months)					
4	Dynamic Pricing Memorandum Account	506,949	6,020,706	182.3	6,019,967	507,688
5	(amortization: < 12 months)					
6	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
7	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
8	Electric Balancing Account Reserve Account	(999,999,999)				-999,999,999
9	Electric Balancing Account Reserve Account	67,770,764	51,690,951	400	166,303,024	-46,841,309
10	(amortization: < 12 months)					
11	Electric Hazardous Substance Balancing Account	19,937,796	41,353,895	182.3	40,179,461	21,112,230
12	(amortization: < 12 months)					
13	Electric Price Risk Management - Current	71,013,015	382,340,226	555	357,208,959	96,144,282
14	Electric Price Risk Management - NonCurrent	126,231,590	735,090,865	555	723,241,334	138,081,121
15	Electric Program Investment Charge	2,418,856	86,150,018	400	85,080,764	3,488,110
16	(amortization: < 12 months)					
17	End-Use Customer Refund Adjustment	47,570,194	42,439,926	400	89,667,817	342,303
18	(amortization: < 12 months)					
19	Energy Data Ctr Memo Acct - Electric	149,021	118,036			267,057
20	(amortization: > 12 Months)					
21	Energy Data Ctr Memo Acct - Gas	121,926	96,575			218,501
22	(amortization: > 12 Months)					
23	Energy Recovery Bonds Balancing Account	(460,641,517)	445,744,767	400	6,819,148	-21,715,898
24	(amortization: < 12 months)					
25	Energy Resource Recovery Account	508,439,558	5,354,573,721	400	5,734,698,659	128,314,620
26	(amortization: < 12 months)					
27	Environmental Compliance	135,945,837	30,477,691	182.3	21,958,334	144,465,194
28	(amortization: 32 years)					
29	Environmental Compliance Non-HSM	71,301,444	8,089,796	228.4	15,995,478	63,395,762
30	(amortization: 32 years)					
31	Family Electric Rate Assistance Balancing Acct	6,312,202	3,622,571	400	6,313,533	3,621,240
32	(amortization: < 12 months)					
33	FASB 109 Regulatory Asset	2,928,507,701	694,023,728	282	29,791,448	3,592,739,981
34	(amortization: 1-45 years)					
35	FASB 109 Regulatory Asset Amortzation	(538,567,000)				-538,567,000
36	(amortization: 1-45 years)					
37	FIN 47 - Regulatory Asset	16,321,186	4,826,265	101	4,165,430	16,982,021
38	Financing Costs - Current	2,097,199		428	29,498	2,067,701
39	(amortization: < 12 months)					
40	Financing Costs Regulatory Asset	22,107,666	29,498	428	2,097,199	20,039,965
41	(amortization: 20 years)					
42	Fire Hazard Prevention Memo Acct	162,479	346,738	182.3	3	509,214
43	(amortization: < 12 Months)					
44	TOTAL	7,687,225,400	25,738,018,587		24,758,332,308	8,666,911,679

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Gas Core Firm Storage Account	5,262,514	52,752,306	400	57,307,006	707,814
2	(amortization: < 12 months)					
3	Gas Hazardous Substance Balancing Account	46,555,128	96,526,630	182.3	93,276,909	49,804,849
4	(amortization: < 12 months)					
5	Gas Hazardous Substance Regulatory Asset	311,605,271	72,542,978	182.3	47,062,798	337,085,451
6	(amortization: 32 years)					
7	GAS LEAK SURVEY AND REPAIR BALANCING ACCOUNT	(16,207,630)	143,670,547	182.3	131,096,357	-3,633,440
8	Amortization : <12 MONTHS					
9	Gas Non-Hazardous Substance Regulatory Asset	126,937,083	18,687,115	228.4	9,620,528	136,003,670
10	(amortization: 32 years)					
11	Gas Pipeline Expense and Capital Balancing Account	37,005	6,745,318	400	669,734	6,112,589
12	(amortization: <12 months)					
13	Gas Price Risk Management - Current	2,381,173	8,627,802	807	9,161,119	1,847,856
14	GPBA-Greenhouse Gas Compliance Subaccount		146,027,154	400	109,750,254	36,276,900
15	(amortization: < 12 months)					
16	Gas Public Purpose Program Surcharge Memo Acct	6,074,458	275,574,353	186	238,967,869	42,680,942
17	(amortization: < 12 months)					
18	Gas Transmission and Storage Memo Account		28,714,902	400	64,681,257	-35,966,355
19	(amortization: < 12 months)					
20	Gas Transmission and Storage Revenue Sharing Mech.	12,648,068	12,781	400	11,370,299	1,290,550
21	(amortization: < 12 months)					
22	GREEN TARIFF SHARED RENEWABLES MEMORANDUM		3,173,194	400	927,026	2,246,168
23	Amortization : < 12 MONTHS					
24	Greenhouse Gas Expense Memo Account	(3,622,916)	1,429,001	400	1,732,251	-3,926,166
25	Hydro Licensing Balancing Account	(10,969,627)	544,481	182.3	16,642,403	-27,067,549
26	(amortization: > 12 Months)					
27	Land Conserv. Plan Env. Remediation Memo Acct.	1,899,432	2,106,043	182.3	1,899,432	2,106,043
28	(amortization: < 12 months)					
29	Major Emergency Balancing Account	(1,130,739)	61,175,012	182.3	73,088,875	-13,044,602
30	(amortization: < 12 Months)					
31	Market Redesign & Technology Memo Account	75,547,281	110,249			75,657,530
32	(amortization: < 12 months)					
33	Miscellaneous Electric Reg Asset - Current	218,075,589	40,602,395	Various	3,203,619	255,474,365
34	(amortization: < 12 months)					
35	Miscellaneous Electric Reg Asset - NonCurrent	25,866,590	43,367,194	549	56,450,394	12,783,390
36	(amortization: 25 years)					
37	Mobile Home Park Balancing Account - Electric	324,027	2,967,460	182.3	342,820	2,948,667
38	(amortization: < 12 months)					
39	Mobile Home Park Balancing Account - Gas	324,027	3,027,587	182.3	342,819	3,008,795
40	(amortization: < 12 months)					
41	Modified transition cost balancing account	99,196,797	117,773,248	400	83,584,111	133,385,934
42	(amortization: < 12 months)					
43	Negative Ongoing Competition Transition Chrg BA	2,841,304,523	99,059,603	182.3	14,701,046	2,925,663,080
44	TOTAL	7,687,225,400	25,738,018,587		24,758,332,308	8,666,911,679

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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.
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1	(amortization: < 12 months)					
2	New System Generation BA	(24,730,502)	204,624,772	400	223,240,933	-43,346,663
3	(amortization: < 12 months)					
4	Non Current HSM BA Elec	21,383,068	40,422,271	182.3	41,552,839	20,252,500
5	(amortization: > 12 months)					
6	Non Current HSM BA Gas	49,893,826	94,318,633	182.3	96,956,624	47,255,835
7	(amortization: > 12 months)					
8	Non-Core Gas Pipeline Safety Bal Acct	(24,138,515)	39,029,956	400	8,789,271	6,102,170
9	(amortization: < 12 Months)					
10	Nuclear Decommissioning Adjustment Mechanism	27,066,222	107,834,013	400	143,692,777	-8,792,542
11	(amortization: 2 years)					
12	Nuclear Regulatory Commission Rulemaking Costs BA	(3,735,730)	18,036,475	182.3	29,325,662	-15,024,917
13	(amortization: > 12 Months)					
14	Pension Regulatory Asset	2,346,797,722	126,161,604	926	59,336,180	2,413,623,146
15	(amortization: indefinite)					
16	Procurement Energy Efficiency Rev. Adj. Mechanism	17,672,250	237,381,982	400	254,205,741	848,491
17	(amortization: < 12 months)					
18	Public Purpose Programs Revenue Adjustment Mech.	(11,001,583)	217,095,173	400	223,319,310	-17,225,720
19	(amortization: < 12 months)					
20	Purchased Gas Balancing Account	19,020,403	2,225,638,618	400	2,246,478,441	-1,819,420
21	(amortization: < 12 months)					
22	Reg Asset - Electric Meters Current	64,373,887	272,671,508	182.3	266,531,207	70,514,188
23	(amortization: < 12 months)					
24	REGULATORY ASSET-CEMA-ELEC-NONCURRENT		127,252,071	588	50,441,275	76,810,796
25	Amortization : > 12 MONTHS					
26	Reliability Services Balancing Account	6,585,510	10,204,541	400	10,692,466	6,097,585
27	(amortization: < 12 months)					
28	Renewables Portfolio Standard Cost Memo Acct	326,269	476			326,745
29	(amortization: < 12 months)					
30	Residential Rate Reform Memorandum Account (RRRMA)		1,683,079			1,683,079
31	(amortization: >12 months)					
32	Revised Customer Energy Stmt. BA - Elec.	3,058,311	1,964,299	182.3	3,060,828	1,961,782
33	(amortization: < 12 months)					
34	Revised Customer Energy Stmt. BA - Gas	2,502,253	1,607,154	182.3	2,504,314	1,605,093
35	(amortization: < 12 months)					
36	SMART GRID MEMORANDUM ACCOUNT	5,271,627	5,962,062	182.3	5,434,612	5,799,077
37	Amortization : < 12 MONTHS					
38	SmartMeter Opt-Out Program Balancing Account-Electc	8,712,904	17,460,327	182.3	19,014,292	7,158,939
39	(amortization: < 12 Months)					
40	SmartMeter Opt-Out Program Balancing Account-Gas	10,878,207	17,643,899	182.3	16,531,456	11,990,650
41	(amortization: < 12 Months)					
42	Transition Cost - Noncore Balancing Account	(12,161,077)	134,769,540	400	130,782,410	-8,173,947
43	(amortization: < 12 months)					
44	TOTAL	7,687,225,400	25,738,018,587		24,758,332,308	8,666,911,679

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	Transmission Access Charge Balancing Account	(43,525,246)	408,525,267	400	253,181,440	111,818,581
2	(amortization: < 12 months)					
3	Transmission Revenue Balancing Account	(13,498,618)	95,581,676	400	144,645,535	-62,562,477
4	(amortization: < 12 months)					
5	Unamortized Financial Hedging Cost	15,288,429		428	836,195	14,452,234
6	(amortization: 20 years)					
7	Unamortized Financial Hedging Cost Current	836,195				836,195
8	(amortization: < 12 months)					
9	URG Plant Regulatory Asset - current	45,057,996		182.3	1,722,996	43,335,000
10	(amortization: < 12 months)					
11	URG Plant Regulatory Asset - noncurrent	941,986,004	1,722,996			943,709,000
12	(amortization: 22 years)					
13	URG Plant Regulatory Asset - Tax	183,010,953				183,010,953
14	(amortization: 11 years)					
15	Vegetation Management Reg. Asset - Current	12,726,483	152,592,444	400	142,739,373	22,579,554
16	(amortization: < 12 months)					
17						
18	Miscellaneous minor items	675,367	895,772,863	Various	896,237,810	210,420
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44	TOTAL	7,687,225,400	25,738,018,587		24,758,332,308	8,666,911,679

Schedule Page: 232.1 Line No.: 6 Column: b

The FERC software will not allow the entire beginning balance of Electric Balancing Account Reserve Account of ($2,932,229,233) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 6:	($999,999,999)
Line 7:	($999,999,999)
Line 8:	($999,999,999)
Line 9:	$67,770,764
Total	($2,932,229,233)

Schedule Page: 232.1 Line No.: 6 Column: f

The FERC software will not allow the entire ending 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 6:	($999,999,999)
Line 7:	($999,999,999)
Line 8:	($999,999,999)
Line 9:	($46,841,308)
Total	($3,046,841,305)

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

Primarily internal labor expenses.

Schedule Page: 232.2 Line No.: 33 Column: d

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

Schedule Page: 232.4 Line No.: 18 Column: d

Primarily Regulatory Asset - Electric Meters, offset to 404 - Amortization of Plant, and Greenhouse Gas Expense Memorandum Account, offset to 400 - Operating Revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	-12,849,435	855,005,472	Various	849,591,319	-7,435,282
2	Customer Adv for Construction	12,015,092	1,978,308	Various	3,731,947	10,261,453
3	Development Costs	44,917,168	3,305,078	131	537,678	47,684,568
4	Payments for MLX and					
5	Non-Energy Invoices	914,637	679,888,628	Various	681,787,408	-984,143
6	Payments for Main Line					
7	Extension	-3,747,619	119,639,334	Various	119,045,299	-3,153,584
8	Clearing Account for					
9	JP Morgan Chase	1,508,245	32,656,585	Various	32,314,145	1,850,685
10	Single Use Auto Clearing	-261,619	15,725,710	Various	16,663,308	-1,199,217
11	Reimburseable Transmission					
12	Interest on Commercial Paper	65,025	3,763,692	431	3,600,301	228,416
13	Interconnection Study Costs	1,617,298	6,511,679	Various	6,540,321	1,588,656
14	Miscellaneous minor items	-36,947	7,791,659,645	Various	7,791,609,909	12,789
15						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	44,141,845				48,854,341

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	02/24/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: d

Accounts charged: 131, 142

Schedule Page: 233 Line No.: 2 Column: d

Accounts charged: 456, 495

Schedule Page: 233 Line No.: 5 Column: d

Accounts charged: 131, 143

Schedule Page: 233 Line No.: 7 Column: d

Accounts charged: 131, 252

Schedule Page: 233 Line No.: 9 Column: d

Accounts charged: 108, 131

Schedule Page: 233 Line No.: 10 Column: d

Accounts charged: 109, 131

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

FY14 end of year balance ($65,025) previously disclosed within the miscellaneous minor items row. End of year 2015 balance exceeds the $100,000 threshold for miscellaneous minor items. As such, interest on commercial paper is being disclosed separately in 2015.

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

Accounts charged: 131, 143

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

Activity primarily reflects payroll clearing account.

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

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	02/24/2016	End of 2015/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	-84,820,239	-98,264,038
3	Compensation	21,926,470	31,480,441
4	CIAC	-201,702,794	-216,936,608
5	Injuries and Damages	123,708,440	111,193,926
6	California Corporation Franchise Tax	123,531,974	163,526,064
7	Other	405,252,274	421,346,952
8	TOTAL Electric (Enter Total of lines 2 thru 7)	387,896,125	412,346,737
9	Gas		
10	Environmental	42,748,989	-2,111,272
11	Compensation	29,009,565	36,989,999
12	CIAC	302,717,834	298,706,854
13	Injuries and Damages	-33,481,745	-39,822,402
14	California Corporation Franchise Tax	2,481,723	-3,868,408
15	Other	1,053,849,331	1,069,891,541
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,397,325,697	1,359,786,312
17	Other	120,119,774	312,153,435
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,905,341,596	2,084,286,484

Notes

(1) Line 17 - Other

	Balance at Beginning of the year	Balance at end of the year
California Corporation Franchise Tax	(172,984,531)	(193,286,134)
Compensation (FKA Pension/PBOP /Severance/Workforce Reduction)	(7,835,010)	(10,849,994)
Other	300,939,315	516,289,407
Total	120,119,774	312,153,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	Undesigned 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		
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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
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						36
10,319,783	257,994,575					37
						38
						39
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						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	02/24/2016	End of 2015/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	5,394,587,624
3	Excess Tax Benefit on Stock Based Compensation	50,960,303
4		
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40	TOTAL	5,445,547,927

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	COMMON	25,143,083
2		
3	PREFERRED, CUMULATIVE:	
4	Redeemable - $25 par value per share:	
5	4.36%	29,509
6	4.50%	387,663
7	4.80%	777,999
8	5.00%	1,758,375
9	5.00% - Series A	158,204
10		
11	Non-Redeemable - $25 par value per share:	
12	5.00%	73,717
13	5.50%	173,730
14	6.00%	449,606
15		
16		
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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	02/24/2016	End of 2015/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		15,892,100,000	226,284,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	3,479,526
29			2,540,000 D
30	Series 4.30% Senior Notes due 2045 4.30%	100,000,000	1,094,824
31			5,231,000 D
32	Series 3.50% Senior Notes due 2025 3.50%	200,000,000	1,710,772
33	TOTAL	15,892,100,000	226,284,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	4,861,738
3			8,415,000 D
4			
5	Pollution Control Bonds		
6	1996 Series 96C/E/F/G Various	527,870,000	5,923,662
7			
8	1997 Series 97B Various	148,550,000	2,129,592
9			
10	2004 Series A-D 4.750%	345,000,000	7,897,424
11			
12	2008 Series F-G Various	95,000,000	692,629
13			
14	2009 Series A-D Various	308,550,000	1,682,621
15			
16	2010 Series E 2.250%	50,000,000	
17			
18	SUBTOTAL ACCOUNT 221	16,099,970,000	226,284,325
19			
20	ACCOUNT 222:		
21	REACQUIRED BONDS		
22	Pollution Control Bonds		
23	1996 Series 96G Variable	-62,870,000	
24			
25	2008 Series F-G Variable	-95,000,000	
26			
27	2010 Series E 2.25%	-50,000,000	
28			
29	SUBTOTAL ACCOUNT 222	-207,870,000	
30			
31			
32			
33	TOTAL	15,892,100,000	226,284,325

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	11,250,000	10
						11
3/3/08	2/15/38	3/3/08	2/15/38	400,000,000	25,400,000	12
						13
10/21/08	10/15/18	10/21/08	10/15/18	600,000,000	49,500,000	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
				15,892,100,000	725,523,837	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	11,250,000	2
						3
4/6/12	4/15/42	4/6/12	4/15/42	400,000,000	17,800,000	4
						5
8/16/12	8/16/22	8/16/12	8/16/22	400,000,000	9,800,000	6
						7
8/16/12	8/16/42	8/16/12	8/16/42	350,000,000	13,125,000	8
						9
6/14/13	6/15/23	6/14/13	6/15/23	375,000,000	12,187,500	10
						11
6/14/13	6/15/43	6/14/13	6/15/43	375,000,000	17,250,000	12
						13
11/12/13	11/15/23	11/12/13	11/15/23	300,000,000	11,550,000	14
						15
11/12/13	11/15/43	11/12/13	11/15/43	500,000,000	25,625,000	16
						17
2/21/14	2/15/24	2/21/14	2/15/24	450,000,000	16,875,000	18
						19
2/21/14	2/15/44	2/21/14	2/15/44	450,000,000	21,375,000	20
						21
8/18/14	8/15/24	8/18/14	8/15/24	350,000,000	11,900,000	22
						23
8/18/14	2/15/44	8/18/14	2/15/44	225,000,000	10,687,500	24
						25
11/6/14	3/15/45	11/6/14	3/15/45	500,000,000	21,500,000	26
						27
6/12/15	6/15/25	6/12/15	6/15/25	400,000,000	7,738,889	28
						29
6/12/15	3/15/45	6/12/15	3/15/45	100,000,000	2,400,833	30
						31
11/5/15	6/15/25	11/5/15	6/15/25	200,000,000	1,088,889	32
				15,892,100,000	725,523,837	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
11/5/15	3/15/46	11/5/15	3/15/46	450,000,000	2,975,000	2
						3
						4
						5
5/23/96	Various	5/23/96	Various	527,870,000	84,517	6
						7
9/16/97	11/1/26	9/16/97	11/1/26	148,550,000	37,320	8
						9
6/29/04	12/1/23	6/29/04	12/1/23	345,000,000	16,387,500	10
						11
9/22/08	Various	9/22/08	Various	95,000,000		12
						13
9/1/09	Various	9/1/09	Various	308,550,000	60,889	14
						15
4/8/10	11/1/26	4/8/10	11/1/26	50,000,000		16
						17
				16,099,970,000	725,523,837	18
						19
						20
						21
						22
				-62,870,000		23
						24
				-95,000,000		25
						26
				-50,000,000		27
						28
				-207,870,000		29
						30
						31
						32
				15,892,100,000	725,523,837	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: 256.1 Line No.: 28 Column: a

Refer to Q2 2015 Note 6 on page 109.3, for CPUC authorization number and date.

Schedule Page: 256.1 Line No.: 30 Column: a

Refer to Q2 2015 Note 6 on page 109.3, for CPUC authorization number and date.

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

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

Schedule Page: 256.2 Line No.: 2 Column: a

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

Schedule Page: 256.2 Line No.: 18 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	725,523,837
Remarketing costs not included on this page	1,128,680
Total Interest expense per page 117	726,652,517

Schedule Page: 256.2 Line No.: 29 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.: 29 Column: i

No interest income or expense are recorded 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	02/24/2016	End of 2015/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)	862,018,078
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	201,384,036
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	43,818,609
11	Provision for State income Taxes	-62,636,648
12	Balancing Accounts	-80,720,799
13	Per attached schedule (See page 261-1)	1,076,274,692
14	Income Recorded on Books Not Included in Return	
15	AFUDC - Equity and debt	154,529,213
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Per attached schedule (See page 261-1)	2,266,272,241
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-380,663,486
28	Show Computation of Tax:	
29	Federal Tax net Income as above $	-133,232,220
30	Tax at 35% for Electric, Non-Utility, and Gas	
31	Other	
32	Add: Tax on FIN 48 Interest	65,330
33	Less: Research & Development Credits	-4,500,000
34	Specified Liability Loss	-87,586,888
35	Other Adjustments	-420,509
36	Reclass tax loss to Deferred	137,732,218
37		
38	Subtotal Tax	-87,942,069
39	FIN 48 Tax Adjustment (net to Gross)	-13,107,000
40	Federal Income Tax Accrual	-101,049,069
41		
42		
43		
44		

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

Deductions recorded on books not deducted on return:

	Total
Executive Compensation	4,826,194
Loss on Reacquired Debt	23,573,353
Compensation Related Adjustments	24,053,147
Meals & Entertainment & Lobbying	15,443,095
Capitalized Interest	76,517,813
Nuclear Fuel expense	122,902,702
GHG Allowances	273,004,448
Penalties	104,281,805
DOE Settlement	5,070,823
Plant Disallowance	405,722,624
Injuries & Damages	13,402,618
Other	7,476,070
Total	$ 1,076,274,692

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

Deductions on return not charged against book income:

Bad Debts	$ (11,807,449)
Computer Software	(147,786,014)
Cost of removal	(221,192,664)
Depreciation adjustment	(852,211,046)
Earnings of Subsidiaries	(1,240,536)
Property Tax	(20,798,918)
Section 263A MSCM	(141,568,800)
Repairs	(736,831,747)
Environmental Cleanup	(45,655,784)
Gas Hedge Amortization	(28,657,684)
Dividends Paid Deduction	(3,540,000)
Nuclear Decom Trust Book Expense	(49,850,805)
Fossil Decommissioning	(5,130,794)
Total	$ (2,266,272,241)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal - FICA	19,655,154		99,866,461	205,361,643	101,059,589
2	Federal - Taxes on Income	-135,462,434		-101,049,069	-87,933,226	100,854,328
3	Federal - Unemployment	2,178,384		2,312,232	3,272,966	
4	Federal - Decommisioning			21,921,928	21,921,928	
5						
6	SUBTOTAL FEDERAL	-113,628,896		23,051,552	142,623,311	201,913,917
7						
8	State - Taxes on Income	446,892		35,970,730	11,708,084	36,549,031
9	State - Unemployment	166,910		11,358,734	11,533,724	
10						
11	SUBTOTAL STATE TAXES	613,802		47,329,464	23,241,808	36,549,031
12						
13	Ad Valorem property	1,103		347,879,153	365,939,518	18,060,365
14	Other	1,903,000		14,109,138	13,551,009	
15						
16	SUBTOTAL OTHER TAXES	1,904,103		361,988,291	379,490,527	18,060,365
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	-111,110,991		432,369,307	545,355,646	256,523,313

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) 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)	
15,219,561		67,853,957			32,012,504	1
-47,723,949		-43,668,897			-57,380,172	2
1,217,650		1,665,732			646,500	3
		21,921,928				4
						5
-31,286,738		47,772,720			-24,721,168	6
						7
61,258,569		197,853,336			-161,882,606	8
-8,080		8,182,832			3,175,902	9
						10
61,250,489		206,036,168			-158,706,704	11
						12
1,103		278,163,986			69,715,167	13
2,461,129		10,164,223			3,944,915	14
						15
2,462,232		288,328,209			73,660,082	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
32,425,983		542,137,097			-109,767,790	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	32,012,504	0	32,012,504
Federal - Taxes on Income	-57,445,500	65,328	-57,380,172
Federal - Unemployment	646,500	0	646,500
Total Federal taxes	-24,786,496	65,328	-24,721,168
State - Taxes on Income	-103,122,857	-58,761,109	-161,883,966
State - Unemployment	3,175,902	0	3,175,902
Total State	-99,946,955	-58,761,109	-158,708,064
Ad Valorem property	69,370,214	344,953	69,715,167
Other	3,944,915	0	3,944,915
Total Other	73,315,129	344,953	73,660,082

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

Adjustment relates to FIN 48 and Balance Sheet reclasses of $100,854,328

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

Adjustment relates to FIN 48 and Balance Sheet reclasses of $36,549,031.

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 include 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	02/24/2016	End of 2015/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%	98,868,000			411.5	-9,631,537	
6							
7							
8	TOTAL	98,868,000				-9,631,537	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	10%	23,395,000			411.5	939,706	
13							
14							
15							
16	Grand	122,263,000				-8,692,000	
17							
18							
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45							
46							
47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
108,499,537	18		5
			6
			7
108,499,537			8
			9
			10
			11
22,455,294	22		12
			13
			14
			15
130,955,000			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
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			39
			40
			41
			42
			43
			44
			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	02/24/2016	End of 2015/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	159,262,700	143,146,456	99,009,527	105,254,452	165,507,625
2						
3	Deferred Credits - Electric	42,095,266	182,232,926	1,886,837	1,323,421	41,531,850
4	Reserves					
5						
6	Other Deferred Credits - Misc	6,154,296	101, 107	1,092,909	15,515,688	20,577,075
7						
8	Other	5,409,631	Various	39,414,703	36,810,677	2,805,605
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	212,921,893		141,403,976	158,904,238	230,422,155

Schedule Page: 269 Line No.: 1 Column: d

Activity includes ~$44M amortization; related deferred credit is amortized over 30 years.

Schedule Page: 269 Line No.: 6 Column: b

FY14 end of year balance ($6,154,296) previously disclosed within the "Other" line item. End of year 2015 balance exceeds the 5% of ending balance ($11,521,108) threshold for other items. As such, other deferred credits - misc is being disclosed separately in 2015.

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

"Other" consists of various other deferred credits amounts with balances of less than 5% of the year end balance. (< 230,422,155 * 5% = 11,521,108)

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

Refer to the footnote on Line 6, 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	02/24/2016	End of 2015/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					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
						307	6
							7
						307	8
							9
							10
							11
							12
							13
							14
							15
							16
						307	17
							18
						307	19
							20
							21

NOTES (Continued)

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	8,150,877,915	531,336,080	290,412,363
3	Gas	2,228,662,367	458,666,968	423,943,755
4	Nonutility	127,433,818		
5	TOTAL (Enter Total of lines 2 thru 4)	10,506,974,100	990,003,048	714,356,118
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	10,506,974,100	990,003,048	714,356,118
10	Classification of TOTAL			
11	Federal Income Tax	8,227,446,023	775,218,113	559,373,835
12	State Income Tax	2,279,528,077	214,784,935	154,982,283
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
					402,235,577	8,794,037,209	2
					185,678,044	2,449,063,624	3
19,526,738	3,907,871				80,411,135	223,463,820	4
19,526,738	3,907,871				668,324,756	11,466,564,653	5
							6
							7
							8
19,526,738	3,907,871				668,324,756	11,466,564,653	9
							10
15,290,338	3,060,043				523,329,153	8,978,849,749	11
4,236,400	847,828				144,995,603	2,487,714,904	12
							13

NOTES (Continued)

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

FERC Form 1 Pages 274-275
12/31/15
Detail of Adjustments

	(402,235,577)	SFAS 109 adjustment - account 182.3
<A>	(402,235,577)	
	($185,677,043)	SFAS 109 adjustment - account 182.3
<B>	($185,677,043)	
	(80,411,136)	SFAS 109 adjustment - account 182.3
<C>	(80,411,136)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	61,922,061	-5,667,574	252,598
4	Balancing Accounts	31,345,503	47,093,309	-85,365,523
5	Other	-1,998,321	90,505	-4,400,147
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	91,269,243	41,516,240	-89,513,072
10	Gas			
11	Loss on Reacquired Debt	30,237,678	-3,651,422	39,988
12	Balancing Accounts	290,118,535	-18,511,341	18,682,236
13				
14	Other	-2,421,918		
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	317,934,295	-22,162,763	18,722,224
18	OTHER	-29,362,331		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	379,841,207	19,353,477	-70,790,848
20	Classification of TOTAL			
21	Federal Income Tax	339,973,506	15,154,666	-55,432,504
22	State Income Tax	39,867,701	4,198,811	-15,358,344
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	02/24/2016	End of 2015/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						56,001,889	3
						163,804,335	4
		0	420,509			2,071,822	5
							6
							7
							8
			420,509			221,878,046	9
							10
						26,546,268	11
						252,924,958	12
							13
						-2,421,918	14
							15
							16
						277,049,308	17
4,867	165,021,345					-194,378,809	18
4,867	165,021,345		420,509			304,548,545	19
							20
3,811	129,219,335		329,278			281,015,874	21
1,056	35,802,010		91,231			23,532,671	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 9 Column: h

$420,509 FIN 48 Adjustment

Schedule Page: 276 Line No.: 19 Column: f

Amount relates to bill credit from San Bruno Penalty Decision by the CPUC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	425,050	182.3	89	432,089	857,050
2	(amortization: <12 months)					
3	Affiliate Transfer Fees Account	162,312	182.3	162,351	167,465	167,426
4	(amortization: <12 months)					
5	Ca Energy Systems for 21st Century B/A-Elec - NC		182.3	2,261,968	3,798,972	1,537,004
6	(amortization: 5 years)					
7	California Solar Initiative	50,437,331	400	78,025,886	95,357,045	67,768,490
8	(amortization: 5 years)					
9	Demand Response Expenditures Balancing Account	87,514,861	400	115,740,731	56,501,736	28,275,866
10	DREBA Operations Balancing Account - Current				75,826,917	75,826,917
11	Electric Price Risk Management - Current	67,438,009	555	320,986,313	347,169,419	93,621,115
12	Electric Price Risk Management - NonCurrent	164,255,004	555	762,194,334	766,605,037	168,665,707
13	Electric Program Investment Charge Balancing Acct	205,845,586	400	117,730,683	85,401,101	173,516,004
14	FAS 143 Regulatory Liability - Nuclear	(999,999,999)				-999,999,999
15	FAS 143 Regulatory Liability - Nuclear	(339,997,875)	Various	206,701,950	149,801,165	-396,898,660
16	FAS 143 Regulatory Liability - Fossil	(114,658,175)	Various	7,511,640	30,703	-122,139,112
17	FAS 143 Regulatory Liability - Fossil Decomm	119,920,930	228.4	3,044,341	39,354,313	156,230,902
18	FAS 143 Regulatory Liability-Nuclear Decomm	2,489,944,183	128	457,803,097	437,459,156	2,469,600,242
19	FIN 47 Regulatory Liability	(401,194,936)	Various	279,501,799	204,867,210	-475,829,525
20	Gas PPP Surcharge-RDD	(934,548)	400	11,362,560	11,108,553	-1,188,555
21	(amortization: <12 months)					
22	Gas Price Risk Management - Current	1,200,783	807	9,033,873	8,036,719	203,629
23	GHGRBA - Greenhouse Gas Revenue Subaccount		400	147,922,582	213,116,469	65,193,887
24	(amortization: <12 months)					
25	GPBA - Greenhouse Gas Revenue Subaccount				58,813,397	58,813,397
26	(amortization: <12 months)					
27	HSM Insurance Recoveries Reg	2,006,521	Various	1,221,883	504,145	1,288,783
28	Miscellaneous Electric Reg Liab - Current	188,115,573	449	151,028,634	140,872,105	177,959,044
29	(amortization: <12 months)					
30	Miscellaneous Electric Reg Liab - NonCurrent	53,592,356	549	19,199,798	8,122,610	42,515,168
31	Miscellaneous Gas Reg Liab - Current				400,000,000	400,000,000
32	(amortization: <12 months)					
33	Miscellaneous Gas Reg Liab - NonCurrent	30,491,218	549	134,842		30,356,376
34	(amortization: 2 years)					
35	Non Current Reg Liab-CC8 Settlement	53,840,351	108	2,361,833		51,478,518
36	(amortization: 25 Years)					
37	Non-Tariffed Products and Svcs BA-Electric	186,354	182.3	1,374,694	1,344,911	156,571
38	(amortization: < 12 months)					
39	Non-Tariffed Products and Svcs BA-Gas	152,397	182.3	233,579	209,223	128,041
40	(amortization: < 12 months)					
41	TOTAL	2,244,891,189		3,944,661,359	4,306,255,566	2,606,485,396

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	On Bill Financing Balancing Electric	18,586,615	930.2	6,272,210	20,446,785	32,761,190
2	On Bill Financing Balancing Gas	4,079,899	930.2	1,376,827	4,488,318	7,191,390
3	PPP (PPPLIBA)-Electric	89,728,340	400	78,572,423	102,793,086	113,949,003
4	(amortization: <12 months)					
5	PPP (PPPLIBA)-Gas	5,924,672	400	68,406,949	73,549,652	11,067,375
6	(amortization: <12 months)					
7	PPP Energy Efficiency-Gas	28,838,253	400	86,378,697	78,504,646	20,964,202
8	PPP Surcharge Energy Efficiency - Gas	(20,442,217)	400	81,858,684	79,711,887	-22,589,014
9	(amortization: <12 months)					
10	PPP Surcharge Low Income - Gas	(15,087,135)	400	72,705,792	70,226,550	-17,566,377
11	(amortization: <12 months)					
12	PPP Surcharge RDD - Current	3,746,227	182.3	10,273,249	10,900,035	4,373,013
13	(amortization: <12 months)					
14	Procurement Energy Efficiency	132,755,492	400	396,063,085	358,151,709	94,844,116
15	PVPMA - Current	23,992,200	182.3	4,720,324	28,234,669	47,506,545
16	(amortization: < 12 months)					
17	Reg Liability Gas Risk MGMT - Noncurrent	925,009	807	5,526,326	5,553,417	952,100
18	Regulatory Liability Retirement	152,158,867	520	66,982,479	61,265,002	146,441,390
19	(amortization: indefinite)					
20	Self Generation Program-Gas	26,255,143	400	7,327,139	8,099,685	27,027,689
21	Self Generation Program - Electric	140,116,977	400	33,379,189	36,928,497	143,666,285
22	Smart Grid Pilot Deployment	983,413	400	10,650,653	5,446,081	-4,221,159
23	(amortization: 4 Years)					
24	SW Marketing, Education and Outreach Program BA	4,915,148	400	46,843,039	45,679,209	3,751,318
25	(amortization: < 12 months)					
26	SW Marketing, Education and Outreach Program BA	1,684,304	400	5,197,214	4,198,882	685,972
27	(amortization: < 12 months)					
28	TAMA - Electric		182.3	12,722,771		-12,722,771
29	(amortization: 2 Years)					
30	TAMA - Gas		182.3	59,765,309		-59,765,309
31	(amortization: 2 Years)					
32						
33	Miscellanous minor items	(13,013,304)	Various	194,099,540	207,176,996	64,152
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	2,244,891,189		3,944,661,359	4,306,255,566	2,606,485,396

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

The FERC software will not allow the entire beginning balance of FAS 143 Regulatory Liability of ($1,339,997,874) 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:	($339,997,875)
Total	($1,339,997,874)

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

The FERC software will not allow the entire ending balance of FAS 143 Regulatory Liability of ($1,339,898,659) 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:	($339,898,660)
Total	($1,339,898,659)

Schedule Page: 278 Line No.: 15 Column: c

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

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 Line No.: 27 Column: c

182.3 - Transferred to balancing accounts for refund to customers and 407.3/426.5 offset to O&M expense.

Schedule Page: 278.1 Line No.: 33 Column: c

Primarily Vegetation Management Balancing Account (VMBA), offset to 400 - Operating Revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	5,031,641,589	4,783,973,961
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	6,511,220,329	6,312,479,524
5	Large (or Ind.) (See Instr. 4)	1,554,743,090	1,543,429,765
6	(444) Public Street and Highway Lighting	69,774,393	70,890,073
7	(445) Other Sales to Public Authorities	3,097,792	2,869,911
8	(446) Sales to Railroads and Railways	9,747,183	5,260,944
9	(448) Interdepartmental Sales	42,247,495	40,815,362
10	TOTAL Sales to Ultimate Consumers	13,222,471,871	12,759,719,540
11	(447) Sales for Resale	18,093,440	71,120,465
12	TOTAL Sales of Electricity	13,240,565,311	12,830,840,005
13	(Less) (449.1) Provision for Rate Refunds	87,833,615	27,064,741
14	TOTAL Revenues Net of Prov. for Refunds	13,152,731,696	12,803,775,264
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,954,221	6,635,333
17	(451) Miscellaneous Service Revenues	7,974,162	9,568,377
18	(453) Sales of Water and Water Power	3,038,309	1,891,832
19	(454) Rent from Electric Property	95,486,423	84,810,257
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-138,450,611	-293,422,709
22	(456.1) Revenues from Transmission of Electricity of Others	8,453,438	12,972,325
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(400) Balancing Accounts	559,692,075	1,109,280,132
26	TOTAL Other Operating Revenues	543,148,017	931,735,547
27	TOTAL Electric Operating Revenues	13,695,879,713	13,735,510,811

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
29,278,920	29,835,314	4,749,484	4,679,176	2
				3
39,848,490	40,041,776	632,081	625,007	4
15,974,630	15,648,127	1,448	1,383	5
372,243	394,666	34,107	33,653	6
20,371	19,903	15	15	7
365,799	360,949	25	25	8
306,967	303,031			9
86,167,420	86,603,766	5,417,160	5,339,259	10
1,813,603	1,585,919	3	3	11
87,981,023	88,189,685	5,417,163	5,339,262	12
				13
87,981,023	88,189,685	5,417,163	5,339,262	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 284,107,411 which was deducted from Line 21 below.

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

Column (b) includes California Department of Water Resources ("DWR") revenues of $445,054,747 which was deducted from Line 21 below.

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

Page 300, Line 17, Column b

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)	1,462
Total	7,974,162

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

This consists of :

NSF fees and rent charges to customers' refundable deposits	2,964,433
MLX billings to electric residential customers	3,620,162
MLX billings to electric non-residential customers	1,160,369
Reimbursable third-party labor requested on behalf of customers	1,823,301
Miscellaneous (items under $250,000)	112
Total	9,568,377

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

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.

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

This consists of :

DWR	(445,054,747)
Unbilled revenues	28,106,658
Other electric revenues not classified elsewhere	56,927,239
Reimbursement to the Utility for costs spent on customer projects	55,682,401
Reimbursement fees paid to the CPUC based on sales	(20,832,153)
Transition Cost Revenue Account for non-bypassable charges	24,466,272
Revenue assigned - base	(15,139,742)
Pass-through franchise fees and uncollectible revenue	15,139,742
Other revenue-damage claim	1,894,640
MCI rights of way	864,577
Fees for customer billing for third party service providers	725,883
Reimbursement to the Utility for costs spent on customer billing	507,232
Employee transfer fees	424,858
Fees for utility energy service contracts	2,196,326
Timber sales	374,631
Miscellaneous (items under $250,000)	293,473
Total	(293,422,709)

The DWR revenues of ($445,054,747) 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	02/24/2016	End of 2015/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					
5					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	19,633,621	3,811,638,284	3,371,131	5,824	0.1941
3	EL1 Residential Care Program S	7,224,347	813,842,546	1,171,811	6,165	0.1127
4	E6 Residential Time-of-Use Servic	248,213	43,155,967	56,382	4,402	0.1739
5	EL6 Residential Care Time-of-U	15,856	1,696,316	2,657	5,968	0.1070
6	E7 Time-of-Use	501,832	87,743,885	57,765	8,687	0.1748
7	EL7 Residential Care Program T	48,891	5,627,139	5,330	9,173	0.1151
8	E8 Seasonal Service Option	523,064	106,472,585	38,969	13,423	0.2036
9	EL8 Residential Seasonal Care	73,602	8,319,635	5,612	13,115	0.1130
10	EA9 Experimental TOU Service for	17,596	2,962,195	2,362	7,450	0.1683
11	EB9 Experimental TOU Service for	395	47,827	137	2,883	0.1211
12	ECLSD		5,040			
13	EVA Residential TOU Service for P	251,853	40,115,190	16,730	15,054	0.1593
14	EVB Residential TOU Service for P	697	85,694	185	3,768	0.1229
15	EM Master-Metered Multi-family Se	234,970	42,998,009	17,047	13,784	0.1830
16	EML Multifamily CARE Program - Ma	23,695	2,463,626	166	142,741	0.1040
17	EMTOU Residential Time of Use Ser	1,071	164,434	47	22,787	0.1535
18	ES Multi-family Service	26,882	4,221,263	284	94,655	0.1570
19	ESL Multifamily CARE Program Serv	29,454	3,993,662	318	92,623	0.1356
20	ESR RV Park and Residential Marin	1,266	197,377	23	55,043	0.1559
21	ESRL RV Park and Residential Mari	7,735	1,069,511	80	96,688	0.1383
22	ET Mobilehome Park Service	16,859	2,506,843	262	64,347	0.1487
23	ETL Low-Income Mobile Home	394,182	51,973,899	2,165	182,070	0.1319
24	MIS-RS		-142,317			
25	SE1 Standby - Individually Metere	25	6,218	1	25,000	0.2487
26	SEM1 Standby - Master-Metered Mul	2,752	449,485	9	305,778	0.1633
27	STOUS INDV Standby - TOU		27,277	11		
28	UNCLASSIFIED	61				
29	Total Residential	29,278,919	5,031,641,590	4,749,484	6,165	0.1719
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	86,167,418	13,240,565,313	5,417,160	15,906	0.1537
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	86,167,418	13,240,565,313	5,417,160	15,906	0.1537

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	1,928,953	376,201,206	87,201	22,121	0.1950
3	A1F Small General Service	72,460	16,047,970	17,697	4,094	0.2215
4	A1X Small General Service	4,935,960	1,029,821,030	325,011	15,187	0.2086
5	A15 Small General Service	452	268,728	435	1,039	0.5945
6	A6 Time-of-Use	1,376,749	267,466,940	26,468	52,016	0.1943
7	A10 Medium General	9,212,483	1,613,517,682	45,805	201,124	0.1751
8	E19 500 to 999 Kw Demand	13,705,508	1,857,711,250	24,045	569,994	0.1355
9	E20 1000 Kw Demand or More	14,161,257	1,341,850,276	1,019	13,897,210	0.0948
10	E37 1000 Kw Demand or More	720,888	80,649,618	457	1,577,435	0.1119
11	MIS-RS		-94,763			
12	AG1 Agricultural Power	186,528	47,824,170	9,790	19,053	0.2564
13	AG4 TOU Agricultural Power	1,249,330	284,631,684	48,873	25,563	0.2278
14	AG5 Large TOU Agricultural Power	5,751,757	843,654,016	23,969	239,966	0.1467
15	AGICE Agricultural Internal Combu	367,214	33,490,739	1,800	204,008	0.0912
16	AGR Split-Wk TOU Agricultural Pow	62,927	14,205,534	2,491	25,262	0.2257
17	AGV Short-Pk TOU Agricultural Pow	39,075	8,960,873	1,671	23,384	0.2293
18	OL1 Outdoor Area Lighting Serv	11,075	3,218,941	15,908	696	0.2906
19	SA1 Standby & General Service	322	69,984	7	46,000	0.2173
20	SA6 Standby & Small TOU	8,032	1,412,311	14	573,714	0.1758
21	SA10 Standby & Alt. Rate for Med-	22,120	3,217,540	33	670,303	0.1455
22	SE19 Standby & 500 to 999 Kw	109,673	16,168,852	70	1,566,757	0.1474
23	SE20 Standby & 1000 Kw Demand	1,170,673	130,099,512	98	11,945,643	0.1111
24	SE37 Standby - Med Gen	80,346	9,181,313	5	16,069,200	0.1143
25	STOUP Standby - TOU Primary	-6,761	4,379,956	209	-32,349	-0.6478
26	STOUT Standby - TOU Transformer	653,990	79,064,763	282	2,319,113	0.1209
27	STOUS INDV Standby - TOU	2,102	1,920,715	171	12,292	0.9138
28	TC1 Traffic Control Service					
29	UNCLASSIFIED	5	1,022,581			204.5162
30	Total Commercial and Industrial	55,823,118	8,065,963,421	633,529	88,115	0.1445
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	86,167,418	13,240,565,313	5,417,160	15,906	0.1537
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	86,167,418	13,240,565,313	5,417,160	15,906	0.1537

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 Public Street and Highway Lig					
2	LS1-A Utility-Owned Street & High	26,318	8,319,072	3,847	6,841	0.3161
3	LS1-B Utility-Owned Street & High	28	6,255	7	4,000	0.2234
4	LS1-C Utility-Owned Street & High	9,580	2,472,535	567	16,896	0.2581
5	LS1-D Utility-Owned Street & High	7,185	2,562,399	979	7,339	0.3566
6	LS1-E Utility-Owned Street & High	19,722	6,391,049	1,697	11,622	0.3241
7	LS1-F Utility-Owned Street & High	8,155	2,878,598	1,659	4,916	0.3530
8	LS2-A Customer-Owned Street & Hig	243,018	35,904,833	9,315	26,089	0.1477
9	LS2-C Customer-Owned Street & Hig	5,630	1,090,020	498	11,305	0.1936
10	LS3 Cust-Owned Street & Highway L	8,732	1,378,325	1,334	6,546	0.1578
11	LS3F Cust-Owned Street & Highway	4,145	760,223	2,230	1,859	0.1834
12	TC1 Traffic Control Service	38,509	7,735,648	11,386	3,382	0.2009
13	TC1F Traffic Control Service	1,221	275,435	588	2,077	0.2256
14	UNCLASSIFIED	1				
15	Total Public Street and Highway	372,244	69,774,392	34,107	10,914	0.1874
16						
17	445 Other Sales to Public Authori					
18	Special Contracts	20,371	3,097,792	15	1,358,067	0.1521
19	Total Other Sales to Public Aut	20,371	3,097,792	15	1,358,067	0.1521
20						
21	446 Sales to Railroads and Railwa					
22	Special Contracts	365,799	9,747,183	25	14,631,960	0.0266
23	Total Sales to Railroads and Ra	365,799	9,747,183	25	14,631,960	0.0266
24						
25	448 Interdepartmental Sales	306,967	42,247,495			0.1376
26	Total Interdepartmental Sales	306,967	42,247,495			0.1376
27						
28	Total Sales to					
29	Ultimate Consumers	86,167,418	13,222,471,873	5,417,160	15,906	0.1535
30						
31	447 Sales for Resale					
32	Special Contracts		18,093,440			
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	86,167,418	13,240,565,313	5,417,160	15,906	0.1537
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	86,167,418	13,240,565,313	5,417,160	15,906	0.1537

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	.2	17.7	17.7
3	Hetch Hetchy	RQ	114	12.1	12.1	12.1
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**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
768	445	23,837		24,282	2
	724,690			724,690	3
1,812,835		17,342,410	2,058	17,344,468	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
1,813,603	725,135	17,366,247	2,058	18,093,440	
0	0	0	0	0	
1,813,603	**725,135**	**17,366,247**	**2,058**	**18,093,440**	

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel	189,655,735	256,825,579
6	(502) Steam Expenses	340,423	128,909
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		1,572
10	(506) Miscellaneous Steam Power Expenses	39,269	278,610
11	(507) Rents		
12	(509) Allowances	70,147,327	52,101,349
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	260,182,754	309,336,019
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures	7,410	9,734
17	(512) Maintenance of Boiler Plant	4,189,830	3,503,473
18	(513) Maintenance of Electric Plant	5,937,595	11,242,074
19	(514) Maintenance of Miscellaneous Steam Plant	2,185,250	1,282,107
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,320,085	16,037,388
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	272,502,839	325,373,407
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel	126,705,233	115,233,156
26	(519) Coolants and Water	31,444,865	35,756,666
27	(520) Steam Expenses	44,671,316	50,368,175
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,199,280	1,978,104
31	(524) Miscellaneous Nuclear Power Expenses	155,982,651	143,161,852
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	361,003,345	346,497,953
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures	2,228,588	12,561,476
37	(530) Maintenance of Reactor Plant Equipment	34,566,278	48,747,580
38	(531) Maintenance of Electric Plant	41,314,819	50,415,539
39	(532) Maintenance of Miscellaneous Nuclear Plant	64,002,629	2,187,154
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	142,112,314	113,911,749
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	503,115,659	460,409,702
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power	2,307,985	2,126,441
46	(537) Hydraulic Expenses	1,706,362	1,016,640
47	(538) Electric Expenses	40,092,844	39,749,011
48	(539) Miscellaneous Hydraulic Power Generation Expenses	45,990,538	41,959,837
49	(540) Rents	805,764	794,366
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	90,903,493	85,646,295
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures	6,735,118	5,663,717
55	(543) Maintenance of Reservoirs, Dams, and Waterways	24,694,303	20,527,215
56	(544) Maintenance of Electric Plant	25,838,644	23,778,210
57	(545) Maintenance of Miscellaneous Hydraulic Plant	11,087,571	9,569,603
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	68,355,636	59,538,745
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	159,259,129	145,185,040

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses	12,392,031	11,882,629
65	(549) Miscellaneous Other Power Generation Expenses	8,651,839	10,047,258
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	21,043,870	21,929,887
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	3,129,265	2,928,864
71	(553) Maintenance of Generating and Electric Plant	8,939,220	7,748,297
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	26,394,822	2,604,345
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	38,463,307	13,281,506
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	59,507,177	35,211,393
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	4,419,716,817	5,026,087,915
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	329,047,197	249,758,767
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,748,764,014	5,275,846,682
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,743,148,818	6,242,026,224
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering		
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	31,486,251	27,839,395
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	27,818,335	27,535,370
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	10,931,830	10,786,626
93	(562) Station Expenses	7,310,475	8,065,388
94	(563) Overhead Lines Expenses	9,269,289	7,241,440
95	(564) Underground Lines Expenses	2,390,838	2,329,747
96	(565) Transmission of Electricity by Others	15,673,592	15,749,704
97	(566) Miscellaneous Transmission Expenses	71,008,557	56,341,796
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	175,889,167	155,889,466
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	1,279,293	2,390,806
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	35,483,435	30,088,385
108	(571) Maintenance of Overhead Lines	71,803,748	52,450,240
109	(572) Maintenance of Underground Lines	778,027	566,835
110	(573) Maintenance of Miscellaneous Transmission Plant	1,478,822	1,661,845
111	TOTAL Maintenance (Total of lines 101 thru 110)	110,823,325	87,158,111
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	286,712,492	243,047,577

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	15,719,229	15,996,882
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	15,719,229	15,996,882
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)	15,719,229	15,996,882
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering		
135	(581) Load Dispatching		
136	(582) Station Expenses	4,320,249	4,571,008
137	(583) Overhead Line Expenses	29,620,496	32,838,919
138	(584) Underground Line Expenses	49,642,215	36,975,331
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	3,964,078	2,382,027
141	(587) Customer Installations Expenses	26,571,529	21,934,169
142	(588) Miscellaneous Expenses	182,496,269	131,182,065
143	(589) Rents		
144	TOTAL Operation (Enter Total of lines 134 thru 143)	296,614,836	229,883,519
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures	4,581,922	3,593,593
148	(592) Maintenance of Station Equipment	33,825,137	33,287,423
149	(593) Maintenance of Overhead Lines	424,992,315	336,699,532
150	(594) Maintenance of Underground Lines	41,800,787	45,256,369
151	(595) Maintenance of Line Transformers	2,949,552	1,675,638
152	(596) Maintenance of Street Lighting and Signal Systems	6,300,405	6,906,992
153	(597) Maintenance of Meters	17,033,078	16,759,638
154	(598) Maintenance of Miscellaneous Distribution Plant	1,596,466	1,031,257
155	TOTAL Maintenance (Total of lines 146 thru 154)	533,079,662	445,210,442
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	829,694,498	675,093,961
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	11,698,199	14,706,007
161	(903) Customer Records and Collection Expenses	173,828,400	164,049,297
162	(904) Uncollectible Accounts	35,171,408	34,358,559
163	(905) Miscellaneous Customer Accounts Expenses	2,095,555	3,073,005
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	222,793,562	216,186,868

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	629,052,968	610,743,581
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	2,470,361	3,862,037
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	631,523,329	614,605,618
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	2,978,856	10,381,680
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	2,978,856	10,381,680
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	313,969,948	318,572,130
182	(921) Office Supplies and Expenses	23,245,746	32,435,339
183	(Less) (922) Administrative Expenses Transferred-Credit	53,445,415	53,730,347
184	(923) Outside Services Employed	200,125,233	150,027,534
185	(924) Property Insurance	16,144,030	15,210,062
186	(925) Injuries and Damages	84,806,973	96,626,937
187	(926) Employee Pensions and Benefits	350,134,384	347,442,118
188	(927) Franchise Requirements	97,921,794	94,332,407
189	(928) Regulatory Commission Expenses		398
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	10,058,156	7,362,114
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	1,042,960,849	1,008,278,692
195	Maintenance		
196	(935) Maintenance of General Plant	9,774,832	9,825,565
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	1,052,735,681	1,018,104,257
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	8,785,306,465	9,035,443,067

Schedule Page: 320 Line No.: 76 Column: b
Of the year end balance, $85,614 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 76 Column: c
Of the end of year balance, $153,016 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: b
Of the year end balance, $7,093 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: c
Of the end of year balance, $6,164 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: b
Of the end of year balance, $176 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: c
Of the end of year balance, $2,486 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: b
Of the year end balance, $1,000,995 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: c
Of the end of year balance, $751,062 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: b
Of the year end balance, $310,050 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: c
Of the end of year balance, $118,419 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: b
Of the year end balance, $79,709 relate to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: c
Of the end of year balance, $72,461 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	02/24/2016	End of 2015/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	N/A	0.05641	N/A
4	GAS RECOVERY SYS. (AMERICAN CYN)	LU	0.00000	0.00	0.00000	N/A
5	MONTEREY REGIONAL WATER	LU	0.00000	N/A	0.37908	N/A
6	NAPA SANITATION DISTRICT	LU	0.00000	N/A	0.00000	N/A
7	WASTE MANAGEMENT RENEWABLE	LU	0.00000	N/A	13.73455	N/A
8	BIOMASS-BURNEY FOREST PRODUCTS	LU	0.00000	24.00	30.48492	N/A
9	COLLINS PINE	LU	0.00000	0.00	5.73025	N/A
10	COVANTA MENDOTA L. P.	LU	0.00000	22.00	23.70292	N/A
11	DG FAIRHAVEN POWER, LLC	LU	0.00000	16.00	17.14170	N/A
12	HUMBOLDT REDWOOD COMPANY	LU	0.00000	0.00	0.68483	N/A
13	HL POWER	LU	0.00000	20.00	26.58749	N/A
14	PACIFIC-ULTRAPOWER CHINESE	LU	0.00000	19.80	19.76400	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	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RIO BRAVO FRESNO	LU	0.00000	23.50	24.87783	N/A
2	RIO BRAVO ROCKLIN	LU	0.00000	22.00	24.73208	N/A
3	SIERRA PACIFIC IND. (ANDERSON)	LU	0.00000	N/A	1.40844	N/A
4	SIERRA PACIFIC IND. (BURNEY)	LU	0.00000	9.50	15.21698	N/A
5	SIERRA PACIFIC IND. (LINCOLN)	LU	0.00000	4.98	11.27033	N/A
6	SIERRA PACIFIC IND. (QUINCY)	LU	0.00000	12.50	21.12269	N/A
7	SIERRA PACIFIC IND.(SONORA)	LU	0.00000	N/A	3.53323	N/A
8	WHEELABRATOR SHASTA	LU	0.00000	49.68	50.62558	N/A
9	GEOTHERMAL-AMEDEE GEOTHERMAL	IU	0.00000	N/A	0.00000	N/A
10	WENDEL ENERGY OPERATIONS 1,LLC	LU	0.00000	0.21	0.52900	N/A
11	HYDRO-EAGLE HYDRO	LU	0.00000	0.00	0.17116	N/A
12	EIF HAYPRESS LLC (LWR)	LU	0.00000	0.00	0.73533	N/A
13	EIF HAYPRESS LLC (MDL)	LU	0.00000	0.00	0.66733	N/A
14	EL DORADO HYDRO LLC (MONTGOMERY	LU	0.00000	0.00	0.90541	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	02/24/2016	End of 2015/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.

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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	ERIC AND DEBBIE WATTENBURG	LU	0.00000	0.00	0.02183	N/A
2	FAIRFIELD POWER PLANT (PAPAZIAN)	LU	0.00000	0.00	0.00000	N/A
3	FAR WEST POWER CORPORATION	LU	0.00000	0.00	0.00000	N/A
4	FIVE BEARS HYDROELECTRIC	LU	0.00000	0.00	0.07108	N/A
5	FRIANT POWER AUTHORITY	LU	0.00000	0.00	1.02767	N/A
6	HAT CREEK HEREFORD RANCH	LU	0.00000	0.00	0.01165	N/A
7	HUMBOLDT BAY MWD	LU	0.00000	0.00	0.58541	N/A
8	HYPOWER, INC.	LU	0.00000	0.00	3.39117	N/A
9	INDIAN VALLEY HYDRO	IU	0.00000	N/A	1.19817	N/A
10	JAMES B. PETER	LU	0.00000	N/A	0.01213	N/A
11	JAMES CRANE HYDRO	LU	0.00000	N/A	0.00057	N/A
12	JOHN NEERHOUT JR.	LU	0.00000	N/A	0.00025	N/A
13	KINGS RIVER HYDRO CO.	LU	0.00000	N/A	0.00000	N/A
14	LASSEN STATION HYDRO	LU	0.00000	N/A	0.44825	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	02/24/2016	End of 2015/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	LOFTON RANCH	LU	0.00000	N/A	0.08200	N/A
2	MALACHA HYDRO L.P.	LU	0.00000	N/A	12.77275	N/A
3	MEGA HYDRO #1 (CLOVER CREEK)	LU	0.00000	N/A	0.35794	N/A
4	MEGA RENEWABLES (BIDWELL DITCH)	LU	0.00000	N/A	1.45478	N/A
5	MEGA RENEWABLES (HATCHET CRK)	LU	0.00000	N/A	1.64275	N/A
6	MEGA RENEWABLES (ROARING CRK)	LU	0.00000	N/A	0.58157	N/A
7	MEGA RENEWABLES (SILVER SPRINGS)	LU	0.00000	N/A	0.17383	N/A
8	MILL & SULPHUR CREEK	LU	0.00000	N/A	0.09491	N/A
9	NELSON CREEK POWER INC.	LU	0.00000	N/A	0.29450	N/A
10	NEVADA IRRIGATION DISTRICT/BOWMAN	LU	0.00000	N/A	1.12008	N/A
11	OLCESE WATER DISTRICT	LU	0.00000	N/A	0.55750	N/A
12	OLSEN POWER PARTNERS	LU	0.00000	N/A	0.88600	N/A
13	ORANGE COVE IRRIGATION DIST.	LU	0.00000	N/A	0.25783	N/A
14	ROBERT W. LEE	LU	0.00000	N/A	0.00000	N/A
	Total					

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1	ROCK CREEK HYDRO, LLC	LU	0.00000	N/A	0.36241	N/A
2	ROCK CREEK WATER DISTRICT	LU	0.00000	N/A	0.20191	N/A
3	SANTA CLARA VALLEY WATER DIST.	LU	0.00000	N/A	0.00000	N/A
4	SCHAADS HYDRO	LU	0.00000	N/A	0.01691	N/A
5	SHAMROCK UTILITIES (CEDAR FLAT)	LU	0.00000	N/A	0.00000	N/A
6	SHAMROCK UTILITIES (CLOVER LEAF)	LU	0.00000	N/A	0.00000	N/A
7	SHEILA ST. GERMAIN	LU	0.00000	N/A	0.00000	N/A
8	SNOW MOUNTAIN HYDRO LLC (BURNEY	LU	0.00000	N/A	0.72325	N/A
9	SNOW MOUNTAIN HYDRO LLC (COVE)	LU	0.00000	N/A	1.26813	N/A
10	SNOW MOUNTAIN HYDRO LLC	LU	0.00000	N/A	0.24650	N/A
11	STEVE & BONNIE TETRICK	LU	0.00000	N/A	0.00000	N/A
12	STEVEN SPELLENBERG HYDRO	LU	0.00000	N/A	0.00000	N/A
13	STS HYDROPOWER LTD. (KANAKA)	LU	0.00000	N/A	0.23933	N/A
14	STS HYDROPOWER LTD. (KEKAWAKA)	LU	0.00000	N/A	2.64945	N/A
	Total					

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1	SUTTER'S MILL	LU	0.00000	N/A	0.06002	N/A
2	SWISS AMERICA	LU	0.00000	N/A	0.03571	N/A
3	TKO POWER (SOUTH FORK BEAR CREEK)	LU	0.00000	N/A	0.40670	N/A
4	TOM BENNINGHOVEN	LU	0.00000	N/A	0.00649	N/A
5	TRI-DAM AUTHORITY	LU	0.00000	15.00	6.09092	N/A
6	WATER WHEEL RANCH	LU	0.00000	N/A	0.22175	N/A
7	WRIGHT RANCH HYDROELECTRIC	LU	0.00000	N/A	0.00038	N/A
8	YOLO COUNTY FLOOD & WCD	LU	0.00000	N/A	0.00000	N/A
9	YUBA COUNTY WATER AGENCY (FISH	LU	0.00000	0.13	0.14210	N/A
10	HYDRO SIERRA ENERGY (DEADWOOD	LU	0.00000	N/A	0.43750	N/A
11	SOLAR-REAL GOODS TRADING CORP.	LU	0.00000	N/A	0.00000	N/A
12	VILLA SORRISO SOLAR	LU	0.00000	N/A	0.00071	N/A
13	WIND-ALTAMONT POWER LLC (3-4)	LU	0.00000	N/A	0.84487	N/A
14	ALTAMONT POWER LLC (4-4)	LU	0.00000	N/A	4.78784	N/A
	Total					

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1	ALTAMONT POWER LLC (6-4)	LU	0.00000	N/A	3.33633	N/A
2	DONALD R. CHENOWETH	LU	0.00000	N/A	0.00173	N/A
3	EDF RENEWABLE WINDFARM V, INC (10	LU	0.00000	N/A	9.70287	N/A
4	EDF RENEWABLE WINDFARM V, INC (70	LU	0.00000	N/A	0.00000	N/A
5	EDF RENEWABLE WINDFARM V, INC (70	LU	0.00000	N/A	2.97242	N/A
6	EDF RENEWABLE WINDFARM V, INC (70	LU	0.00000	N/A	0.00000	N/A
7	GREEN RIDGE POWER LLC (100 MW - A)	LU	0.00000	N/A	22.63132	N/A
8	GREEN RIDGE POWER LLC (100 MW - D)	LU	0.00000	N/A	2.58518	N/A
9	GREEN RIDGE POWER LLC (110 MW)	LU	0.00000	N/A	29.81800	N/A
10	GREEN RIDGE POWER LLC (23.8 MW)	LU	0.00000	N/A	4.59750	N/A
11	GREEN RIDGE POWER LLC (5.9 MW)	LU	0.00000	N/A	2.53993	N/A
12	GREEN RIDGE POWER LLC (70 MW)	LU	0.00000	N/A	15.70093	N/A
13	INTERNATIONAL TURBINE RESEARCH	LU	0.00000	N/A	13.38758	N/A
14	THERMAL:		0.00000		0.00000	
	Total					

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1	COGEN-1080 CHESTNUT CORP.	LU	0.00000	N/A	0.00480	N/A
2	AIRPORT CLUB	LU	0.00000	N/A	0.00023	N/A
3	ARDEN WOOD BENEVOLENT ASSOC.	LU	0.00000	N/A	0.00025	N/A
4	CALPINE KING CITY COGEN.	LU	0.00000	111.00	121.36717	N/A
5	CARDINAL COGEN	LU	0.00000	N/A	28.02680	N/A
6	CHEVRON RICHMOND REFINERY	LU	0.00000	N/A	1.98933	N/A
7	CITY OF MILPITAS	LU	0.00000	N/A	0.03042	N/A
8	COUNTY OF SANTA CRUZ (WATER ST.	LU	0.00000	N/A	0.00000	N/A
9	CROCKETT COGEN	LU	0.00000	240.00	239.16809	N/A
10	FRESNO COGENERATION PARTNERS, LP	LU	0.00000	33.00	46.87650	N/A
11	FRITO-LAY COGEN	LU	0.00000	N/A	0.43766	N/A
12	GRAPHIC PACKAGING INTERNATIONAL,	IU	0.00000	17.00	21.97350	N/A
13	GREATER VALLEJO RECREATION	LU	0.00000	N/A	0.03231	N/A
14	GREENLEAF UNIT #1	LU	0.00000	49.20	36.24319	N/A
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1	GREENLEAF UNIT #2	LU	0.00000	49.20	49.53975	N/A
2	HAYWARD AREA REC & PARK DIST.	LU	0.00000	N/A	0.03246	N/A
3	J.R. WOOD	LU	0.00000	N/A	0.00000	N/A
4	MARTINEZ COGEN LIMITED	IU	0.00000	N/A	0.00000	N/A
5	NIHONMACHI TERRACE	LU	0.00000	N/A	0.01062	N/A
6	OCCIDENTAL POWER	LU	0.00000	N/A	0.00000	N/A
7	OILDALE ENERGY LLC	IU	0.00000	29.00	38.66417	N/A
8	PE - BERKELEY, INC.	LU	0.00000	22.47	26.21517	N/A
9	PE - KES KINGSBURG,LLC	LU	0.00000	34.50	31.46660	N/A
10	PHILLIPS 66	LU	0.00000	N/A	5.44300	N/A
11	RIO BRAVO POSO	LU	0.00000	30.00	0.00000	N/A
12	RIPON COGENERATION, LLC	LU	0.00000	42.00	48.15885	N/A
13	SANGER POWER, L.L.C.	LU	0.00000	38.00	42.45133	N/A
14	SANTA CRUZ COGEN (PORTER COLLEGE)	LU	0.00000	N/A	0.00000	N/A
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PURCHASED POWER (Account 555)
(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.
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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	SATELLITE SENIOR HOMES	LU	0.00000	N/A	0.00975	N/A
2	SRI INTERNATIONAL	LU	0.00000	N/A	2.08358	N/A
3	STANFORD ENERGY GROUP	LU	0.00000	N/A	0.00000	N/A
4	UCSC PHYSICAL PLANT	LU	0.00000	N/A	0.00000	N/A
5	WESTMOOR HIGH SCHOOL	LU	0.00000	N/A	0.00000	N/A
6	YOUNG RADIO INC.	LU	0.00000	N/A	0.00000	N/A
7	YUBA CITY COGEN	LU	0.00000	46.00	47.07248	N/A
8	YUBA CITY RACQUET CLUB	LU	0.00000	N/A	0.00731	N/A
9	ECO SERVICES OPERATIONS LLC	LU	0.00000	N/A	0.74975	N/A
10	EOR-AERA ENERGY LLC (SOUTH	LU	0.00000	N/A	0.50451	N/A
11	AERA ENERGY LLC. (COALINGA)	LU	0.00000	N/A	2.09224	N/A
12	BADGER CREEK LIMITED	IU	0.00000	42.00	0.00000	N/A
13	BEAR MOUNTAIN LIMITED	LU	0.00000	42.00	48.81600	N/A
14	BERRY PETROLEUM COMPANY -	LU	0.00000	0.00	11.68748	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	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	BERRY PETROLEUM COMPANY -	IU	0.00000	0.00	36.86376	N/A
2	CHALK CLIFF LIMITED	IU	0.00000	42.00	0.00000	N/A
3	CHEVRON MCKITTRICK	LU	0.00000	N/A	4.13337	N/A
4	CHEVRON U.S.A. INC. (SE KERN RIVER)	LU	0.00000	N/A	17.75517	N/A
5	CHEVRON USA (COALINGA)	LU	0.00000	N/A	2.56808	N/A
6	CHEVRON USA (CYMRIC)	LU	0.00000	N/A	7.94000	N/A
7	CHEVRON USA (EASTRIDGE)	LU	0.00000	N/A	20.47675	N/A
8	CHEVRON USA (TAFT/CADET)	LU	0.00000	N/A	2.56375	N/A
9	COALINGA COGENERATION COMPANY	LU	0.00000	37.70	39.19275	N/A
10	LIVE OAK LIMITED	IU	0.00000	42.00	0.00000	N/A
11	MCKITTRICK LIMITED	IU	0.00000	42.00	0.00000	N/A
12	MIDSET COGEN CO.	LU	0.00000	34.70	37.27850	N/A
13	SALINAS RIVER COGEN CO	LU	0.00000	34.70	37.24775	N/A
14	SARGENT CANYON COGENERATION	LU	0.00000	33.50	36.78800	N/A
	Total					

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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(Including power exchanges)

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1	WESTERN POWER & STEAM, INC.	LU	0.00000	17.75	18.23026	N/A
2	FREEPORT-MCMORAN OIL & GAS LLC	LU	0.00000	N/A	1.57267	N/A
3	FREEPORT-MCMORAN OIL & GAS LLC	IU	0.00000	N/A	1.21533	N/A
4						
5						
6						
7						
8						
9	BILATERALS		0.00000		0.00000	
10						
11	2041 ALVARES PRISTINE SUN		0.00000		0.00000	
12	2056 JARDINE PRISTINE SUN LLC		0.00000		0.00000	
13	2065 ROGERS PRISTINE SUN FUND 5 LLC		0.00000		0.00000	
14	2094 BUZZELLE PRISTINE SUN LLC		0.00000		0.00000	
	Total					

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	2096 COTTON PRISTINE SUN LLC		0.00000		0.00000	
2	2097 HELTON PRISTINE SUN, LLC		0.00000		0.00000	
3	2102 CHRISTENSEN PRISTINE SUN		0.00000		0.00000	
4	2103 HILL PRISTINE SUN LLC		0.00000		0.00000	
5	2113 FITZJARRELL PRISTINE SUN		0.00000		0.00000	
6	2125 JARVIS PRISTINE SUN		0.00000		0.00000	
7	2127 HARRIS PRISTINE SUN LLC		0.00000		0.00000	
8	2158 STROING PRISTINE SUN FUND 5 LLC		0.00000		0.00000	
9	ABEC BIDART OLD RIVER		0.00000		0.00000	
10	ABEC BIDART-STOCKDALE LLC		0.00000		0.00000	
11	AGUA CALIENTE SOLAR, LLC		0.00000		0.00000	
12	ALAMO SOLAR		0.00000		0.00000	
13	ALGONQUIN SKIC 20 SOLAR, LLC		0.00000		0.00000	
14	ALPAUGH NORTH, LLC		0.00000		0.00000	
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1	APEX 646-460		0.00000		0.00000	
2	ARLINGTON WIND POWER PROJECT		0.00000		0.00000	
3	Atwell Island		0.00000		0.00000	
4	AV Solar Ranch One		0.00000		0.00000	
5	BADGER CREEK LIMITED CHP RFO-2		0.00000		0.00000	
6	BAKER CREEK HYDROELECTRIC		0.00000		0.00000	
7	BAKERSFIELD 111, LLC		0.00000		0.00000	
8	BARCLAYS CAPITAL ELECTRIC		0.00000		0.00000	
9	BEAR CREEK SOLAR LLC		0.00000		0.00000	
10	BEAR MOUNTAIN LIMITED		0.00000		0.00000	
11	BEAR MOUNTAIN LIMITED (2013 CHP		0.00000		0.00000	
12	BIG CREEK WATER WORKS, LTD.		0.00000		0.00000	
13	Big Valley Power		0.00000		0.00000	
14	Blackspring Ridge 1A		0.00000		0.00000	
	Total					

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1	Blackspring Ridge 1B		0.00000		0.00000	
2	BLAKE'S LANDING FARMS INC		0.00000		0.00000	
3	Bonneville Power (BPA Transmission)		0.00000		0.00000	
4	BONNEVILLE POWER ADMINSTRATION		0.00000		0.00000	
5	BOTTLE ROCK Power LLC		0.00000		0.00000	
6	BROWNS VALLEY IRRIGATION DISTRICT		0.00000		0.00000	
7	BUCKEYE HYDROELECTRIC PROJECT		0.00000		0.00000	
8	BUCKEYE HYDROELECTRIC PROJECT		0.00000		0.00000	
9	BUENA VISTA ENERGY, LLC		0.00000		0.00000	
10	CAL RENEW (AKA CLEAN TECH) - COD:		0.00000		0.00000	
11	CALAVERAS PUBLIC UTILI. DIST. 1		0.00000		0.00000	
12	CALAVERAS PUBLIC UTILI. DIST. 2		0.00000		0.00000	
13	CALAVERAS PUBLIC UTILI. DIST. 3		0.00000		0.00000	
14	CALPINE - DELTA RA PURCHASE 2014 &		0.00000		0.00000	
	Total					

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1	CALPINE - SUTTER RA PURCHASE 2014		0.00000		0.00000	
2	CALPINE ENERGY - AGNEWS, INC		0.00000		0.00000	
3	Calpine Energy - EEI		0.00000		0.00000	
4	Calpine Energy - WSPP		0.00000		0.00000	
5	Calpine Energy Services, LP		0.00000		0.00000	
6	CALPINE GEYSERS (200/425 MW)		0.00000		0.00000	
7	CALPINE GEYSERS II - 175 MW		0.00000		0.00000	
8	CALPINE GEYSERS RETAINED ASSET		0.00000		0.00000	
9	Calpine Local RA Feb 2015 (120 MW)		0.00000		0.00000	
10	CALPINE LOS ESTEROS UPGRADE		0.00000		0.00000	
11	Calpine Los Medanos RA Purchase 2013-2		0.00000		0.00000	
12	CALPINE PEAKERS		0.00000		0.00000	
13	CALPINE RUSSELL CITY - COD JUNE 2010		0.00000		0.00000	
14	CALRENEW-1 LLC		0.00000		0.00000	
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CAMS-DOUBLE C LIMITED		0.00000		0.00000	
2	CAMS-HIGH SIERRA LIMITED		0.00000		0.00000	
3	CAMS-KERN FRONT LIMITED		0.00000		0.00000	
4	CASTELANELLI BROS BIOGAS		0.00000		0.00000	
5	CED WHITE RIVER SOLAR 2, LLC		0.00000		0.00000	
6	CEDAR FLAT		0.00000		0.00000	
7	CENTRAL VALLEY AG POWER		0.00000		0.00000	
8	CHALK CLIFF LIMITED		0.00000		0.00000	
9	CHALK CLIFF LIMITED (2013 CGO FRO-2)		0.00000		0.00000	
10	CID SOLAR, LLC		0.00000		0.00000	
11	CITY OF SANTA CLARA SVP MUNI		0.00000		0.00000	
12	CLOVER FLAT LFG		0.00000		0.00000	
13	CLOVER LEAF		0.00000		0.00000	
14	CLOVERDALE SOLAR 1, 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	02/24/2016	End of 2015/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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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	COLUMBIA SOLAR ENERGY, LLC		0.00000		0.00000	
2	COPPER MOUNTAIN 10		0.00000		0.00000	
3	COPPER MOUNTAIN SOLAR 2 (SEMPRA)		0.00000		0.00000	
4	COPPER MOUNTAIN SOLAR 48		0.00000		0.00000	
5	CORAM BRODIE WIND		0.00000		0.00000	
6	Corcoran Solar		0.00000		0.00000	
7	Desert Center Solar Farm		0.00000		0.00000	
8	DIGGER CREEK HYDRO		0.00000		0.00000	
9	DTE Stockton		0.00000		0.00000	
10	DWR KRCD CAISO REVENUES		0.00000		0.00000	
11	Dynegy Moss Landing		0.00000		0.00000	
12	DYNEGY MOSS LANDING UNITS 6&7		0.00000		0.00000	
13	ECOS ENERGY HOLLISTER PROJECT LLC		0.00000		0.00000	
14	ECOS ENERGY KETTLEMAN 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	02/24/2016	End of 2015/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	ECOS ENERGY LLC KETTLEMAN SOLAR		0.00000		0.00000	
2	ECOS ENERGY MERCED SOLAR		0.00000		0.00000	
3	ECOS ENERGY MISSION SOLAR		0.00000		0.00000	
4	EDF TRADING EEI		0.00000		0.00000	
5	EDF TRADING NORTH AMERICA, LLC		0.00000		0.00000	
6	EIF PANOCHE (FIREBAUGH)		0.00000		0.00000	
7	EL DORADO IRRIGATION		0.00000		0.00000	
8	Energy America - Feb 2015 (134 MW)		0.00000		0.00000	
9	ENERPARC CA1 LLC		0.00000		0.00000	
10	EURUS (AVENAL PARK, LLC)		0.00000		0.00000	
11	EURUS (SAND DRAG, LLC)		0.00000		0.00000	
12	EURUS (SUN CITY PROJECT, LLC)		0.00000		0.00000	
13	Exelon Feb 2015 System (18MW)		0.00000		0.00000	
14	EXELON GENERATION		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	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Exelon Generation Company, LLC		0.00000		0.00000	
2	Exelon Jan/Feb 2014 4/8 MW Sale		0.00000		0.00000	
3	Exelon RA import Allocation Rights Aug		0.00000		0.00000	
4	Exelon RA Sale 2015 Annual (50MW)		0.00000		0.00000	
5	FALL RIVER MILLS A (ACHOMAWI)		0.00000		0.00000	
6	FALL RIVER MILLS B (AHJUMAWI)		0.00000		0.00000	
7	FPLE DIABLO WINDS		0.00000		0.00000	
8	FRESH AIR ENERGY IV, LLC-SONORA 1		0.00000		0.00000	
9	FRESNO SOLAR SOUTH		0.00000		0.00000	
10	FRESNO SOLAR WEST		0.00000		0.00000	
11	GAS TRANSPORT ASSOC WITH PANOCHE		0.00000		0.00000	
12	GAS TRANSPORT ASSOC. WITH MARSH		0.00000		0.00000	
13	GAS TRANSPORT ASSOC. WITH MIRANT		0.00000		0.00000	
14	GASNA 16P, LLC - LA JOYA DEL SOL #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	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	GENESIS SOLAR, LLC		0.00000		0.00000	
2	Genon Energy, Inc		0.00000		0.00000	
3	GENON NRG EEI		0.00000		0.00000	
4	GENON- PITTS 5,6,7 (2011-2015)		0.00000		0.00000	
5	GLOBAL AMPERSAND, CHOWCHILLA		0.00000		0.00000	
6	GLOBAL AMPERSAND, EL NIDO		0.00000		0.00000	
7	GREEN LIGHT ENERGY - SIRUIS SOLAR		0.00000		0.00000	
8	GWF Energy II LLC		0.00000		0.00000	
9	GWF HANFORD 2013-2022		0.00000		0.00000	
10	GWF HENRIETTA 2013-2022		0.00000		0.00000	
11	GWF TRACY REPOWERING PPA		0.00000		0.00000	
12	Halkirk I Wind Project		0.00000		0.00000	
13	HATCHET RIDGE WIND LLC		0.00000		0.00000	
14	HIGH PLAIN RANCH II		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	02/24/2016	End of 2015/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	High Plain Ranch III		0.00000		0.00000	
2	HOLLISTER SOLAR ECOS ENERGY		0.00000		0.00000	
3	IBERDROLA KLONDIKE (AKA PPM		0.00000		0.00000	
4	IBERDROLA RENEWABLES (AKA PPM		0.00000		0.00000	
5	ICE		0.00000		0.00000	
6	JACKSON VALLEY IRRIGATION DIST		0.00000		0.00000	
7	JR SIMPLOT		0.00000		0.00000	
8	KEKAWAKA CREEK (STS)		0.00000		0.00000	
9	KENT SOUTH - PV 2		0.00000		0.00000	
10	KERN RIVER COGEN (KRCC)		0.00000		0.00000	
11	KINGSBURG 1 - TULARE PV II LLC		0.00000		0.00000	
12	KINGSBURG 2 - TULARE PV 11 LLC		0.00000		0.00000	
13	KINGSBURG 3 - TULARE PV 11 LLC		0.00000		0.00000	
14	KLONDIKE WIND IIIA POWER		0.00000		0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	LA JOYA DEL SOL #1 (GASNA 16P, LLC)		0.00000		0.00000	
2	LIVE OAK LIMITED		0.00000		0.00000	
3	LIVE OAK LIMITED (2013 CHP FRO-2)		0.00000		0.00000	
4	Los Esteros Toll		0.00000		0.00000	
5	LOST CREEK 1		0.00000		0.00000	
6	LOST CREEK 2		0.00000		0.00000	
7	MADERA CHOWCHILLA SITE 980		0.00000		0.00000	
8	MAMMOTH G1 (ORMAT) - RAM 2		0.00000		0.00000	
9	MAMMOTH G3 (M3 ORMAT) - RAM 1		0.00000		0.00000	
10	MARIPOSA ENERGY, LLC		0.00000		0.00000	
11	MARSH LANDING		0.00000		0.00000	
12	MARTINEZ COGEN LP (TESORO)		0.00000		0.00000	
13	MCFADDEN HYDROELECTRIC FACILITY		0.00000		0.00000	
14	MCKITTRICK LIMITED (2013 CHP FRO-2)		0.00000		0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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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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	MCKITTRICK LIMITTED		0.00000		0.00000	
2	MERCED IRRIGATION DISTRICT		0.00000		0.00000	
3	MERCED SOLAR ECOS ENERGY		0.00000		0.00000	
4	MESQUITE SOLAR		0.00000		0.00000	
5	MIDWAY SUNSET COGENERATION		0.00000		0.00000	
6	MIDWAY SUNSET PPA		0.00000		0.00000	
7	MILL SULPHUR CREEK PROJECT		0.00000		0.00000	
8	Mirant Marsh Landing, LLC		0.00000		0.00000	
9	MISSION SOLAR ECOS ENERGY		0.00000		0.00000	
10	MOJAVE SOLAR		0.00000		0.00000	
11	MONTEZUMA WIND II (NEXTERA)		0.00000		0.00000	
12	Morgan Stanley		0.00000		0.00000	
13	MT. POSO (RED HAWK)		0.00000		0.00000	
14	NDP1 (SUN HARVEST SOLAR, LLC)		0.00000		0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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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	NEVADA IRRIGATION DISTRICT NORTH		0.00000		0.00000	
2	NEVADA IRRIGATION DISTRICT SCOTTS		0.00000		0.00000	
3	NEVADA IRRIGATION DISTRICT SOUTH		0.00000		0.00000	
4	NEVADA IRRIGATION DISTRICT - Chicago		0.00000		0.00000	
5	NEVADA IRRIGATION DISTRICT-DUTCH		0.00000		0.00000	
6	NEXTERA MONTEZUMA WIND		0.00000		0.00000	
7	NICKEL 1 (NLH1 SOLAR, LLC)		0.00000		0.00000	
8	NLP		0.00000		0.00000	
9	NOBLE AMERICAS		0.00000		0.00000	
10	Noble Americas - Hercules		0.00000		0.00000	
11	NOBLE AMERICAS HERCULES		0.00000		0.00000	
12	NORTH SKY RIVER ENERGY CENTER		0.00000		0.00000	
13	NORTH STAR SOLAR		0.00000		0.00000	
14	NRG Alpine 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	02/24/2016	End of 2015/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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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	NRG SOLAR KANSAS SOUTH		0.00000		0.00000	
2	OAKLEY EXECUTIVE LLC		0.00000		0.00000	
3	OAKLEY EXECUTIVE RV AND BOAT		0.00000		0.00000	
4	OLD RIVER ONE LLC - RAM 3		0.00000		0.00000	
5	ORION SOLAR I, LLC		0.00000		0.00000	
6	Oroville Cogen		0.00000		0.00000	
7	ORTIGALITA POWER COMPANY LLC		0.00000		0.00000	
8	PACIFICORP TSA		0.00000		0.00000	
9	PCWA - LINCOLN HYDROELECTRIC		0.00000		0.00000	
10	Placer County Water Agency		0.00000		0.00000	
11	PRISTINE SUN 5 2041 ALVARES		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					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PUTAH CREEK SOLAR FARMS		0.00000		0.00000	
2	RIPON COGENERATION LLC		0.00000		0.00000	
3	RISING TREE WIND FARM II LLC - RAM 4		0.00000		0.00000	
4	Russell City		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	SCE Purchase/Sell Aug 2015 600 MW		0.00000		0.00000	
9	SDG&E Jan 2015 300 MW Sale		0.00000		0.00000	
10	SEMPRA COPPER MOUNTAIN SOLAR		0.00000		0.00000	
11	Sempra Generation		0.00000		0.00000	
12	SEMPRA MESQUITE SOLAR		0.00000		0.00000	
13	SHAFTER SOLAR LLC		0.00000		0.00000	
14	SHASTA RENEWABLE RESOURCES, 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	02/24/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SHELL ENERGY NORTH AMERICA		0.00000		0.00000	
2	SHILOH I WIND PROJECT LLC		0.00000		0.00000	
3	SHILOH II WIND (AKA ENXCO)		0.00000		0.00000	
4	SHILOH III (ENXCO)		0.00000		0.00000	
5	SHILOH IV		0.00000		0.00000	
6	SIERRA GREEN ENERGY LLC		0.00000		0.00000	
7	SIERRA PACIFIC INDUSTRIES		0.00000		0.00000	
8	SIERRA PACIFIC INDUSTRIES REC PSA		0.00000		0.00000	
9	Sierra Pacific Power Company		0.00000		0.00000	
10	Silicon Valley		0.00000		0.00000	
11	Silray Foothill		0.00000		0.00000	
12	SOLAR PARTNERS II (IVANPAH UNIT 1)		0.00000		0.00000	
13	SOLAR PARTNERS VIII (IVANPAH UNIT 3)		0.00000		0.00000	
14	SOUTH FEATHER WATER AND POWER		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)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	SOUTH SUTTER WATER DISTRICT		0.00000		0.00000	
2	STARWOOD POWER MIDWAY, LLC		0.00000		0.00000	
3	SUN HARVEST SOLAR NDP1		0.00000		0.00000	
4	SUNRISE POWER COMPANY LLC		0.00000		0.00000	
5	Sunshine Gas Landfill		0.00000		0.00000	
6	Tenaska Power Services CO. SALE PART I		0.00000		0.00000	
7	TFS ENERGY - GAS BROKER		0.00000		0.00000	
8	THREE FORKS		0.00000		0.00000	
9	TOPAZ SOLAR FARM		0.00000		0.00000	
10	TORO SLO LANDFILL		0.00000		0.00000	
11	Transalta Energy Marketing		0.00000		0.00000	
12	TUNNEL HILL HYDROELECTRIC PROJECT		0.00000		0.00000	
13	TUNNEL HILL HYDROELECTRIC PROJECT		0.00000		0.00000	
14	TWIN VALLEY HYDRO		0.00000		0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	VANTAGE WIND (POWEREX S&F)		0.00000		0.00000	
2	VANTAGE WIND ENERGY LLC		0.00000		0.00000	
3	VASCO WINDS (NEXTERA)		0.00000		0.00000	
4	VINTNER SOLAR PROJECT		0.00000		0.00000	
5	WADHAM ENERGY LTD. PART.		0.00000		0.00000	
6	WATER WHEEL RANCH		0.00000		0.00000	
7	WEST ANTELOPE - RAM 1		0.00000		0.00000	
8	WESTERN ANTELOPE BLUE SKY RANCH		0.00000		0.00000	
9	WESTERN ELECTRICITY COORDINATING		0.00000		0.00000	
10	WESTLANDS SOLAR FARMS LLC		0.00000		0.00000	
11	White River Solar 2, LLC		0.00000		0.00000	
12	WIND RESOURCE I (CalWind) - RAM 1		0.00000		0.00000	
13	WIND RESOURCE II (CALWIND) - RAM 2		0.00000		0.00000	
14	WOODLAND BIOMASS		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	02/24/2016	End of 2015/Q4

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	YOLO COUNTY GRASSLAND #3		0.00000		0.00000	
2	YOLO COUNTY GRASSLAND #4		0.00000		0.00000	
3						
4						
5	AMP charges		0.00000		0.00000	
6	CP Power		0.00000		0.00000	
7	Energy Connect		0.00000		0.00000	
8	EnerNoc Inc		0.00000		0.00000	
9						
10	Pipeline charges		0.00000		0.00000	
11	Core gas supply		0.00000		0.00000	
12	GTN LLC		0.00000		0.00000	
13	RUBY PIPELINE		0.00000		0.00000	
14	WILLIAMS FIELD SERVICES -		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	02/24/2016	End of 2015/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						
2	Other charges		0.00000		0.00000	
3	Irrigation districts		0.00000		0.00000	
4	Liberty Utilities		0.00000		0.00000	
5	ISO charges for storage cost		0.00000		0.00000	
6	ISO charges (net of storage cost but		0.00000		0.00000	
7	Gas purchases, storage cost & forex		0.00000		0.00000	
8	CARB fees		0.00000		0.00000	
9	Consultancy fees		0.00000		0.00000	
10	Gas Hedges & brokers fees		0.00000		0.00000	
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
							2
19			68	736		804	3
							4
986			6,046	33,381		39,427	5
							6
36,990			200,283	1,144,737		1,345,020	7
221,351			5,658,314	15,092,585		20,750,899	8
10,371			-284,718	589,391		304,673	9
6,156			86,127	2,019,596		2,105,723	10
114,899			2,590,872	8,224,807		10,815,679	11
1,401				111,672		111,672	12
183,423			3,765,805	14,487,207		18,253,012	13
133,918			3,146,097	8,854,216		12,000,313	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
194,699			5,140,448	13,246,352		18,386,800	1
188,103			4,976,223	12,665,042		17,641,265	2
1,928			37,695	102,980		140,675	3
65,317			1,286,698	3,717,201		5,003,899	4
51,756			1,034,794	2,927,548		3,962,342	5
94,058			1,797,596	5,323,594		7,121,190	6
12,775			256,713	712,733		969,446	7
399,348			9,029,025	29,628,252		38,657,277	8
				30		30	9
192			-17,635	3,785		-13,850	10
211			482	6,950		7,432	11
826			6,852	47,453		54,305	12
1,049			8,628	60,212		68,840	13
2,500			20,730	141,373		162,103	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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 Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6			15	339		354	1
							2
							3
-1			-9	-32		-41	4
6,851			108,115	389,888		498,003	5
51			56	1,727		1,783	6
3,280			13,771	102,114		115,885	7
8,392			59,387	260,734		320,121	8
1,555			13,796	63,507		77,303	9
83			81	2,621		2,702	10
5			10	176		186	11
1			2	53		55	12
							13
2,357			28,661	76,397		105,058	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
545			3,171	16,377		19,548	1
16,555			999,072	1,073,301		2,072,373	2
1,486			12,738	48,687		61,425	3
10,099			176,384	299,330		475,714	4
4,250			36,224	138,164		174,388	5
2,148			16,600	72,449		89,049	6
1,263			25,763	38,239		64,002	7
519				20,355		20,355	8
496			4,306	15,807		20,113	9
4,769			105,367	147,790		253,157	10
1,801			16,884	102,809		119,693	11
1,299			9,119	42,324		51,443	12
1,830			40,827	58,385		99,212	13
							14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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 Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
96			856	5,586		6,442	1
581			4,406	33,100		37,506	2
							3
23			56	682		738	4
558			4,228	31,844		36,072	5
225			1,891	12,817		14,708	6
							7
336			3,207	19,419		22,626	8
3,415			26,684	191,097		217,781	9
302			2,458	14,418		16,876	10
							11
							12
126			968	7,249		8,217	13
1,238			3,024	61,530		64,554	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
350			1,841	19,902		21,743	1
238			1,642	7,820		9,462	2
1,165			7,114	66,320		73,434	3
42			188	1,890		2,078	4
29,977			2,594,008	978,964		3,572,972	5
1,131				38,399		38,399	6
2			2	66		68	7
							8
1,199			22,113	38,230		60,343	9
391			3,421	12,176		15,597	10
							11
5			18	171		189	12
3,377			58,419	103,688		162,107	13
19,260			332,845	592,994		925,839	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
13,340			247,720	410,795		658,515	1
12			40	405		445	2
22,443			296,704	686,588		983,292	3
							4
7,404			205,665	233,318		438,983	5
							6
73,151			1,581,710	4,068,024		5,649,734	7
4,903			101,396	274,519		375,915	8
53,307			1,043,973	2,692,566		3,736,539	9
16,757			282,224	914,237		1,196,461	10
8,550			178,174	475,713		653,887	11
52,876			28,671	1,707,429		1,736,100	12
27,300			698,483	1,543,287		2,241,770	13
							14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
34			89	1,256		1,345	1
1			3	44		47	2
1			3	33		36	3
438,853			25,023,576	14,371,993		39,395,569	4
36,825			76,594	1,418,191		1,494,785	5
4,751			18,966	119,049		138,015	6
132			357	5,351		5,708	7
				2		2	8
1,669,943			50,344,685	53,024,249		103,368,934	9
9,873			7,281,436	439,513		7,720,949	10
641			3,363	20,691		24,054	11
75,217			626,645	2,425,675		3,052,320	12
252			589	9,546		10,135	13
31,092			9,277,681	1,319,599		10,597,280	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
225,149			10,015,788	7,204,563		17,220,351	1
295			662	11,510		12,172	2
							3
156,040			434,199	5,254,337		5,688,536	4
73			208	2,771		2,979	5
							6
103,952			1,474,459	3,490,303		4,964,762	7
211,546			4,684,189	6,950,744		11,634,933	8
56,689			8,918,102	2,634,402		11,552,504	9
10,370			27,146	378,036		405,182	10
			13,710	9,335,176		9,348,886	11
15,188			645,226	587,001		1,232,227	12
129,439			8,382,706	5,742,896		14,125,602	13
							14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
8				232		232	1
6,113			14,368	197,757		212,125	2
							3
							4
							5
							6
24,782			10,209,986	857,282		11,067,268	7
62			134	2,478		2,612	8
687			2,122	22,714		24,836	9
22			55	1,015		1,070	10
9,162			43,046	293,910		336,956	11
116,099			533,273	3,884,631		4,417,904	12
121,456			3,181,141	4,096,267		7,277,408	13
80,480			592,931	2,578,294		3,171,225	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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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)	
139,573			1,233,685	4,554,571		5,788,256	1
48,787			572,549	1,753,607		2,326,156	2
20,410			10,103	947,796		957,899	3
81,594			448,566	2,706,941		3,155,507	4
9,063			52,376	288,481		340,857	5
39,344			199,497	1,253,142		1,452,639	6
39,756			182,661	1,251,211		1,433,872	7
7,518			42,132	243,719		285,851	8
285,848			3,301,222	10,083,560		13,384,782	9
122,556			224,654	4,103,203		4,327,857	10
47,712			561,281	1,756,807		2,318,088	11
281,022			3,015,980	9,811,930		12,827,910	12
256,848			3,035,307	9,028,028		12,063,335	13
264,946			3,008,743	9,249,477		12,258,220	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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

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134,974			1,178,048	4,372,333		5,550,381	1
7,734			36,683	247,006		283,689	2
1,125			2,102	40,005		42,107	3
							4
							5
							6
							7
							8
							9
							10
93				20,385		20,385	11
2,472				382,869		382,869	12
540				75,761		75,761	13
1,099				177,985		177,985	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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

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1,863				308,834		308,834	1
1,797				328,044		328,044	2
2,264				357,056		357,056	3
676				98,554		98,554	4
471				77,975		77,975	5
477				73,548		73,548	6
1,986				301,154		301,154	7
1,043				160,925		160,925	8
10,280				1,508,274		1,508,274	9
							10
739,276				128,159,504		128,159,504	11
38,557				2,428,060		2,428,060	12
35,997				2,768,688	-54,444	2,714,244	13
183,396				28,136,519		28,136,519	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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

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1,689				243,796		243,796	1
188,270				19,410,215		19,410,215	2
41,646				6,427,583		6,427,583	3
623,360				95,650,111		95,650,111	4
8,119			3,092,808	37,849		3,130,657	5
2,084				186,332		186,332	6
1,027				187,658		187,658	7
					-3,806	-3,806	8
3,236				544,860		544,860	9
1,830			748,111	6,802		754,913	10
19,570			2,344,698	96,519		2,441,217	11
2,493				272,914		272,914	12
					-14,039	-14,039	13
					16,888,705	16,888,705	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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

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8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					18,179,222	18,179,222	1
216				19,329		19,329	2
					16,025	16,025	3
				557,838		557,838	4
17,303				1,797,661	-712,711	1,084,950	5
937				87,815		87,815	6
9				902		902	7
706				69,820		69,820	8
99,051				5,630,001		5,630,001	9
4,112				806,549		806,549	10
187				19,960		19,960	11
216				23,200		23,200	12
85				8,607		8,607	13
			10,727,995			10,727,995	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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.
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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)	
			6,356,700			6,356,700	1
30,843			5,957,260	244,386		6,201,646	2
			3,983,160		3,176,500	7,159,660	3
			537,040		549,780	1,086,820	4
			6,786,970			6,786,970	5
3,542,137			18,717,000	253,475,682		272,192,682	6
				-167,799		-167,799	7
					11,364	11,364	8
			-237,600			-237,600	9
360,629			61,238,954	2,714,381		63,953,335	10
			4,331,600			4,331,600	11
169,508			46,267,985	3,634,961		49,902,946	12
2,777,357			127,558,592	16,145,381		143,703,973	13
6,188				1,509,958		1,509,958	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours 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)	
50,828			5,099,350	487,027		5,586,377	1
51,964			4,992,429	504,253		5,496,682	2
42,075			5,078,843	453,962		5,532,805	3
1,006				106,298		106,298	4
50,171				6,050,989		6,050,989	5
120				10,376		10,376	6
							7
3,212			154,409	80,343		234,752	8
10,395			2,938,399	111,290		3,049,689	9
54,341				4,371,749		4,371,749	10
							11
4,771				424,790		424,790	12
177				15,861		15,861	13
2,680				425,398		425,398	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
8,926				333,596		333,596	1
6,449				1,023,882		1,023,882	2
356,522				45,816,519		45,816,519	3
30,398				4,787,847		4,787,847	4
235,024				26,867,359		26,867,359	5
52,451				7,514,322		7,514,322	6
682,240				113,794,911		113,794,911	7
2,417				215,421		215,421	8
337,289				44,093,505		44,093,505	9
				-168,214		-168,214	10
			4,279,795			4,279,795	11
				37,820		37,820	12
1,958				299,028		299,028	13
201				22,764		22,764	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,200				356,296		356,296	1
1,712				266,722		266,722	2
1,356				218,382		218,382	3
600				15,004		15,004	4
200				5,388		5,388	5
874,584			51,902,235	5,238,418		57,140,653	6
32,465				4,096,990		4,096,990	7
			-134,000			-134,000	8
3,394				541,193		541,193	9
12,826				3,201,768		3,201,768	10
40,918				10,173,133		10,173,133	11
42,964				10,681,212		10,681,212	12
			-16,200			-16,200	13
52,000			-274,000	1,366,439		1,092,439	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
			-142,000			-142,000	1
			-10,800			-10,800	2
			-49,000			-49,000	3
			-406,200			-406,200	4
3,530				568,463		568,463	5
3,573				574,851		574,851	6
42,615				2,654,115		2,654,115	7
3,454				536,314		536,314	8
284				28,881		28,881	9
240				24,392		24,392	10
				1,080,302		1,080,302	11
				152,449		152,449	12
				702,517		702,517	13
2,570				341,012	-147,000	194,012	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
619,920				131,765,094		131,765,094	1
			1,892,000			1,892,000	2
			624,000			624,000	3
147,587			34,186,281	-7,286,079		26,900,202	4
64,398				7,425,970		7,425,970	5
63,940				7,187,498		7,187,498	6
2				160		160	7
103,740			8,173,013	565,169		8,738,182	8
98,539			8,171,504	1,464,186		9,635,690	9
96,780			8,245,717	1,214,840		9,460,557	10
664,440			59,360,691	5,165,111		64,525,802	11
					17,614,712	17,614,712	12
272,072				28,958,378		28,958,378	13
564,813				70,084,912		70,084,912	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
111,817				14,640,416		14,640,416	1
663				123,393		123,393	2
209,119				12,233,469		12,233,469	3
				4,472,934		4,472,934	4
					166,850	166,850	5
281				32,520		32,520	6
3,203				79,622		79,622	7
1,658				115,743		115,743	8
54,996				4,531,565		4,531,565	9
740,223			22,376,452	20,596,402		42,972,854	10
2,751				418,772		418,772	11
2,786				423,407		423,407	12
1,362				207,179		207,179	13
223,127				18,189,801		18,189,801	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
546				103,154		103,154	1
218			154,409	-2,214		152,195	2
9,868			2,938,399	63,959		3,002,358	3
4,609			5,684,073	32,671		5,716,744	4
3,930				433,728		433,728	5
1,987				220,056		220,056	6
							7
51,421				4,449,492		4,449,492	8
88,703				7,991,614		7,991,614	9
85,837			29,023,983	571,579		29,595,562	10
95,617			107,220,654	2,030,050		109,250,704	11
64,240			427,180	2,090,303		2,517,483	12
							13
11,278			2,344,995	372,839		2,717,834	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
3,997			748,111	13,096		761,207	1
-5,766				1,520,717		1,520,717	2
657				112,690		112,690	3
115,251				18,053,980		18,053,980	4
683,402			10,395,008	-2,235,503		8,159,505	5
244,160			1,018,172	7,319,783		8,337,955	6
707				63,501		63,501	7
			10,635,489	-30,706		10,604,783	8
659				110,626		110,626	9
510,070				98,337,800		98,337,800	10
224,356				22,916,467		22,916,467	11
174,247				5,754,349		5,754,349	12
248,603				30,886,965		30,886,965	13
1,043				98,115		98,115	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
950				118,933		118,933	1
2,066				209,302		209,302	2
1,465				136,323		136,323	3
70,421				9,668,123		9,668,123	4
51,082				10,730,932		10,730,932	5
99,298				10,029,065		10,029,065	6
2,715				396,365		396,365	7
					-60,023	-60,023	8
9,585				650,794		650,794	9
1,190				40,414	40,414	80,828	10
576				39,110		39,110	11
408,475				35,549,899		35,549,899	12
94,736				11,724,929		11,724,929	13
158,428				24,456,622		24,456,622	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
53,312				5,402,049		5,402,049	1
176				19,339		19,339	2
2,189				350,223		350,223	3
51,837				3,691,132		3,691,132	4
32,237				4,078,973		4,078,973	5
1,528			1,003,108	45,614		1,048,722	6
1				186		186	7
					16,611	16,611	8
15,343				2,167,939		2,167,939	9
274,477				28,156,822		28,156,822	10
488				72,149		72,149	11
1,281				199,003		199,003	12
502				79,708		79,708	13
2,427				375,295		375,295	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
5,201				446,359		446,359	1
31,569			6,875,531	304,066		7,179,597	2
17,622				1,074,616		1,074,616	3
122,716			12,442,994	814,860		13,257,854	4
1,437				127,680		127,680	5
156				19,269		19,269	6
6,103				631,429		631,429	7
			-12,000			-12,000	8
			-214,500			-214,500	9
85,131				14,087,504		14,087,504	10
			28,600			28,600	11
280,933				46,164,592		46,164,592	12
19,841				2,382,498		2,382,498	13
3,208					-129,991	-129,991	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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)	
			-1,335,800			-1,335,800	1
206,860				11,722,823		11,722,823	2
403,235				35,713,142		35,713,142	3
274,099				31,475,077		31,475,077	4
302,734				27,280,895		27,280,895	5
85				12,846		12,846	6
70,395				6,393,999		6,393,999	7
					861,568	861,568	8
					52,569	52,569	9
			9,814			9,814	10
					-40,072	-40,072	11
202,034				33,400,741	-1,076,680	32,324,061	12
219,410				36,540,993	-1,817,340	34,723,653	13
244,991			4,183,627	8,566,024		12,749,651	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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 ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
68				6,260		6,260	1
82,881			12,858,862	489,013		13,347,875	2
1,408				132,309		132,309	3
			12,657,600			12,657,600	4
141,863				17,118,097		17,118,097	5
				-285,158		-285,158	6
					21,250	21,250	7
4,295				429,945		429,945	8
1,298,740				226,034,691		226,034,691	9
8,581				1,049,988		1,049,988	10
326,402				9,759,026		9,759,026	11
39				3,882		3,882	12
1,251				131,101		131,101	13
647				89,224		89,224	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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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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)	
				9,335,783		9,335,783	1
235,575				22,604,747		22,604,747	2
253,449				27,372,778		27,372,778	3
3,872				621,611		621,611	4
153,596				14,071,880		14,071,880	5
691				61,383		61,383	6
64,141				4,746,357		4,746,357	7
55,799				3,217,751		3,217,751	8
					118,671	118,671	9
46,143				6,007,854		6,007,854	10
59,202				6,886,352		6,886,352	11
11,831				851,932		851,932	12
34,873				2,527,743		2,527,743	13
172,882				19,436,235		19,436,235	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,016				260,413		260,413	1
2,208				292,869		292,869	2
							3
							4
							5
			1,820,324	140,047		1,960,371	6
			-55,385	-86,537		-141,922	7
			4,150,591	364,592		4,515,183	8
							9
							10
					89,918	89,918	11
					10,442	10,442	12
					15,133,333	15,133,333	13
					2,747	2,747	14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
541,979					32,959,559	32,959,559	3
3,942					791,322	791,322	4
					85,614	85,614	5
16,470,996					673,262,921	673,262,921	6
					140,841,052	140,841,052	7
					397,634	397,634	8
					459,783	459,783	9
					50,726,583	50,726,583	10
							11
							12
							13
							14
49,974,000			946,942,689	2,504,355,085	968,419,043	4,419,716,817	

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	CITY & COUNTY OF SAN FRANCISCO			
7	TRANSMISSION	CCSF	CCSF	LFP
8	INTERRUPTIBLE TRANSMISSION	Various	CCSF	NF
9				
10	CALIFORNIA DEPARTMENT OF WATER			
11	RESOURCES (DWR)			
12	HIGH VOLTAGE	DWR	Various	LFP
13	LOW VOLTAGE	DWR	Various	LFP
14				
15	SF BAY AREA RAPID TRANSIT (BART)	NCPA/WAPA	SF BART	LFP
16				OLF
17	TRANSMISSION AGENCY OF			
18	NORTHERN CALIFORNIA (TANC)	Various	Various	LFP
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						1
						2
227	Various	Various	29	73,482	73,482	3
						4
						5
						6
114	Newark	Various	175	539,979	539,979	7
114	Newark	Various				8
						9
						10
						11
77	Various	Various				12
77	Various	Various				13
						14
12	COTP Terminus/Tracy	Various	67	379,258	368,451	15
						16
						17
143	Midway	Various	233	329,538	323,306	18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			504	**1,322,257**	**1,305,218**	

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
43,551	24,492		68,043	3
				4
				5
				6
	3,140,417	-426,508	2,713,909	7
				8
				9
				10
		-144,153	-144,153	11
				12
				13
				14
4,197,149		-5,893	4,191,256	15
				16
				17
	1,658,466	-34,083	1,624,383	18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
4,240,700	**4,823,375**	**-610,637**	**8,453,438**	

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

Revenue data represent transmission only.

CCSF and WAPA act as their own Scheduling Coordinators and, as such, are charged losses by the California Independent System Operator ("CAISO"). The Utility does not have access to the loss data under the CAISO. Further, these customers are 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.

The CCSF IA was terminated on July 1, 2015.

Schedule Page: 328 Line No.: 6 Column: a

Revenue data represent transmission only.

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.

CCSF and WAPA act as their own Scheduling Coordinators and, as such, are charged losses by the California Independent System Operator ("CAISO"). The Utility does not have access to the loss data under the CAISO. Further, these customers are 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.

The CCSF IA was terminated on July 1, 2015.

Schedule Page: 328 Line No.: 10 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.

CDWR IA was terminated on December 31, 2014.

Schedule Page: 328 Line No.: 15 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 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.

Schedule Page: 328 Line No.: 18 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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	California - Oregon							
2	Transmission Project	OS					276,612	276,612
3	Pacificorp	OS			14,500,000		292,063	14,792,063
4	Sacramento Municipal							
5	Utility District	OS			89,400			89,400
6	Western Area Power							
7	Administration	OS			1,768			1,768
8	California-Oregon							
9	Intertie	OS					513,749	513,749
10	Other	OS						
11								
12								
13								
14								
15								
16								
	TOTAL				14,591,168		1,082,424	15,673,592

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	02/24/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Clearing Account Adjustments	-836,324
7	MCI-PG&E Exchange Rights	864,577
8	Intervenor Compensation	6,093,260
9	Bank Service Fees	4,100,578
10	Consulting Services, Outside Attorn Fees & Contracts	756,024
11	Cash Bonus from Procurement Card Usage	-165,692
12	Misc. Cash Receipts (recovery of unclaimed funds)	-625,282
13	Payroll and Other Tax Adjustments	87,631
14	Return of Undistributed Gift Cards	-182,946
15	Misc. Non-PO Credit Memo's	-31,846
16	Other Miscellaneous Adjustments	-1,824
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	10,058,156

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,984,443		2,984,443
2	Steam Production Plant	61,049,110				61,049,110
3	Nuclear Production Plant	231,504,623			38,731,572	270,236,195
4	Hydraulic Production Plant-Conventional	52,470,501			4,752,000	57,222,501
5	Hydraulic Production Plant-Pumped Storage	5,011,675			3,372,000	8,383,675
6	Other Production Plant	41,811,111				41,811,111
7	Transmission Plant	234,360,028				234,360,028
8	Distribution Plant	959,681,315				959,681,315
9	Regional Transmission and Market Operation					
10	General Plant	10,768,787				10,768,787
11	Common Plant-Electric	131,562,501		180,550,310		312,112,811
12	TOTAL	1,728,219,651		183,534,753	46,855,572	1,958,609,976

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: Frahchise 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 67.13%.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Intangible Plant						
13	302	113,750,070	40.00		2.17	SQ	25.00
14	303	2,482,275	3.00			SQ	-14.00
15	Subtotal	116,232,345					
16							
17	Steam Prod - Fossil					0	
18	311	112,125,238	75.00		3.63	L0	69.00
19	312	273,493,692	50.00		3.70	R1	44.00
20	313						
21	314	248,783,088	40.00		3.58	R2.5	34.00
22	315	50,697,111	30.00		3.51	R4	24.00
23	316	28,295,579	40.00		3.76	L0.5	34.00
24	Subtotal	713,394,708					
25							
26	Hydraulic Production						
27	331	428,450,107	100.00	-1.00	0.97	S2.5	76.00
28	332	1,943,104,867	100.00	-2.00	1.28	S2.5	71.00
29	333	789,278,656	51.00	-6.00	2.19	R1.5	35.00
30	334	253,646,444	50.00	-9.00	3.21	R1.5	33.00
31	335	87,261,944	40.00	-14.00	3.93	R2	26.00
32	336	73,960,001	65.00	-3.00	2.52	R1.5	44.00
33	Subtotal	3,575,702,019					
34							
35	Nuclear Prod-Diablo						
36	321	1,036,743,265	100.00	-1.00	0.93	R1	73.00
37	322	3,432,483,225	60.00	-1.00	2.50	R1	39.00
38	323	1,162,811,055	40.00	-1.00	1.41	R3	14.00
39	324	808,988,441	75.00	-1.00	1.14	R1.5	50.00
40	325	1,055,904,489	40.00	-2.00	4.47	R4	26.00
41	Subtotal	7,496,930,475					
42							
43	Other Production						
44	341	210,375,654	55.00		3.72	R5, R1	50.00
45	342	11,264,118	50.00		3.73	R5,R1	45.00
46	343	223,711,698	40.00		3.59	R5,R2.5	34.00
47	344	353,570,942	27.00		4.27	R5, R2.5, SQ	23.00
48	345	210,675,563	35.00		3.76	R5,R2.5	30.00
49	346	95,867,567	26.00		4.13	R5,S0.5,SQ	20.00
50	Subtotal	1,105,465,542					

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	244,899,372			4.00		-20.00
14	352	411,126,471	65.00	-20.00	1.80	R3	55.00
15	353	5,205,577,725	45.00	-19.00	2.64	R2, R1.5, SQ	35.00
16	354	786,215,619	75.00	-61.00	2.14	R4, R5	55.00
17	355	902,849,368	52.00	-60.00	2.87	R1.5	41.00
18	356	1,387,318,870	60.00	-65.00	2.71	R2.5, R3	44.00
19	357	351,257,648	60.00		1.68	R5	48.00
20	358	257,949,627	55.00	-10.00	1.99	R3	44.00
21	359	63,834,857	60.00	-10.00	1.93	R1.5	50.00
22	Subtotal	9,611,029,557					
23							
24	Transmission-Diablo						
25	352.01	4,880,936	60.00	-20.00	1.37	R5	31.00
26	353.01	89,586,025	43.00	-4.00	2.96	R1.5,R5	28.00
27	Subtotal	94,466,961					
28							
29	Distribution						
30	361	314,904,461	55.00	-20.00	2.25	S5	39.00
31	362	3,003,824,747	40.00	-21.00	2.93	R2.5	27.00
32	363	32,814,644			6.64	R2	-3.00
33	364	3,732,691,533	42.00	-105.00	5.03	R1.5	28.00
34	365	4,265,768,766	42.00	-108.00	5.21	R2	28.00
35	366	2,652,279,272	54.00	-40.00	2.91	R4	37.00
36	367	4,095,122,779	42.00	-43.00	3.08	R3	26.00
37	368	2,916,391,575	31.00	-7.00	3.56	R2.5,R3	20.00
38	369	3,011,526,441	45.00	-57.00	3.38	R3,R4	27.00
39	370	1,079,398,099	20.00	-9.00	5.75	R1.5	15.00
40	371	27,313,911	40.00			S1	8.00
41	372	895,448	16.00			S1	-23.00
42	373	212,846,207	25.00	-23.00	3.97	R0.5,S6,L0,L3	7.00
43	Subtotal	25,345,777,883					
44							
45	General Plant						
46	390	11,254,863	40.00	-10.00	2.08	R3	23.00
47	391	13,258,919	20.00		7.20	SQ	11.00
48	394	103,985,003	25.00		3.66	SQ	18.00
49	395	14,403,678	20.00		9.49	SQ	14.00
50	396	271,612	20.00		6.34	SQ	2.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	136,120,007	15.00		5.04	SQ	14.00
13	398	10,876,557	20.00		13.75	SQ	5.00
14	Subtotal	290,170,639					
15							
16	General Plant Diablo						
17	391.01	1,872,495	20.00		5.13	SQ	18.00
18	398.01	8,049,765	20.00		5.13	SQ	17.00
19							
20	Subtotal	9,922,260					
21							
22	Total	48,359,092,389					
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
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Schedule Page: 336.2 Line No.: 24 Column: a

(1) Column (b) amounts obtained from depreciable and amortizable plant account balances as of 12/31/13.

(2) Plant depreciation parameters and rates (other than for fossil, hydro, and Diablo Canyon) are based on mortality characteristics adopted in Decisions 11-05-018 and 10-11-018.

Depreciation rates for fossil, hydro, and Diablo Canyon are based on the estimated remaining useful life of the power plants, as required by Decisions 11-05-018 and 10-11-018.

(3) For Transmission Plant, column (e) reflects accrual rates based on FERC authorized depreciation parameters. For all other Plant, column (e) reflects accrual rates based on CPUC jurisdiction and authorized depreciation parameters in Decision 11-05-018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Annual fees paid for Diablo Canyon Power Plant				
2	in accordance with Part 171				
3	Docket# 05000275	4,474,472		4,474,472	
4	Docket# 05000323	4,474,472		4,474,472	
5	General Accrual	-211,200		-211,200	
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	1,279,870		1,279,870	
11	Docket# 05000323	1,224,103		1,224,103	
12	General Accrual				
13					
14	Annual fees paid for Diablo Canyon Power Plant				
15	in accordance with Part 171				
16	Docket# 05000275	507,278		507,278	
17	Docket# 05000323	507,278		507,278	
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	1,186,430		1,186,430	
24	Docket# 05000323	1,006,881		1,006,881	
25	Docket# 07200026	34,387		34,387	
26	General Accrual	597,200		597,200	
27					
28	Fees paid for Diablo Canyon Power Plant				
29	for inspection, license renewal, operator				
30	examination in accordance with Part 170				
31	Docket# 05000275	206,766		206,766	
32	Docket# 05000323	189,187		189,187	
33	General Accrual	129,100		129,100	
34					
35	Annual fees paid for Humbolt Bay Power Plant				
36	in accordance with Part 171 (Docket# 05000133)	222,750		222,750	
37					
38	*All paid to US Nuclear Regulatory Commission				
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	16,162,874		16,162,874	

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	4,474,472					3
Electric	524	4,474,472					4
Electric	524	-211,200					5
							6
							7
							8
							9
Electric	524	1,279,870					10
Electric	524	1,224,103					11
							12
							13
							14
							15
Electric	532	507,278					16
Electric	532	507,278					17
Electric	532	333,900					18
							19
							20
							21
							22
Electric	107	1,186,430					23
Electric	107	1,006,881					24
Electric	107	34,387					25
Electric	107	597,200					26
							27
							28
							29
							30
Electric	101	206,766					31
Electric	101	189,187					32
Electric	101	129,100					33
							34
							35
Electric	524	222,750					36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		16,162,874					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	02/24/2016	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A2, A3	Electric Program Investment Charge
2		
3		
4		
5		
6	A2, A3	Customer Energy Services - Cyber Security and Grid Integratn
7		
8		
9		
10	A1(e)	Customer Energy Services - California Solar Initiative
11		
12		
13		
14		
15	A3, A1(e)	SmartGrid
16		
17		
18		
19		
20		
21		
22	Total	
23		
24		
25		
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36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
117,688,169		408	220,308		1
		588	116,825,080		2
		926	712,665		3
		456	-69,884		4
					5
2,714,845		408	4,634		6
		588	2,693,948		7
		926	16,263		8
					9
1,751,913		408	7		10
		926	21		11
		456	-2,511,423		12
		908	4,263,308		13
					14
1,379,977		408	22,196		15
		548	172,969		16
		549	66,679		17
		588	1,034,340		18
		926	82,711		19
		930	1,082		20
					21
123,534,904			123,534,904		22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Schedule Page: 352 Line No.: 4 Column: f

Revenues represent cofunding agreements, whereby PG&E is reimbursed costs incurred on behalf of the parties in these cofunding agreements.

Schedule Page: 352 Line No.: 12 Column: f

Revenues represent cofunding agreements, whereby PG&E is reimbursed costs incurred on behalf of the parties in these cofunding agreements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	224,481,644		
4	Transmission	61,911,140		
5	Regional Market			
6	Distribution	149,220,127		
7	Customer Accounts	117,277,221		
8	Customer Service and Informational	75,475,130		
9	Sales	1,414,377		
10	Administrative and General	315,061,962		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	944,841,601		
12	Maintenance			
13	Production	104,395,203		
14	Transmission	26,336,185		
15	Regional Market			
16	Distribution	155,849,105		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	286,580,493		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	328,876,847		
21	Transmission (Enter Total of lines 4 and 14)	88,247,325		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	305,069,232		
24	Customer Accounts (Transcribe from line 7)	117,277,221		
25	Customer Service and Informational (Transcribe from line 8)	75,475,130		
26	Sales (Transcribe from line 9)	1,414,377		
27	Administrative and General (Enter Total of lines 10 and 17)	315,061,962		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,231,422,094		1,231,422,094
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	3,635,666		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	2,954,026		
35	Transmission	57,729,773		
36	Distribution	161,501,890		
37	Customer Accounts	84,333,386		
38	Customer Service and Informational	21,210,665		
39	Sales	6,321,381		
40	Administrative and General	122,239,032		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	459,925,819		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)	19,053		
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,774,261		
47	Transmission	64,170,643		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	67,845,941		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	133,809,898		
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,	3,654,719		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	4,728,287		
56	Transmission (Lines 35 and 47)	121,900,416		
57	Distribution (Lines 36 and 48)	229,347,831		
58	Customer Accounts (Line 37)	84,333,386		
59	Customer Service and Informational (Line 38)	21,210,665		
60	Sales (Line 39)	6,321,381		
61	Administrative and General (Lines 40 and 49)	122,239,032		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	593,735,717		593,735,717
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	1,825,157,811		1,825,157,811
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	720,094,658		720,094,658
69	Gas Plant	325,758,360		325,758,360
70	Other (provide details in footnote):	172,881,977		172,881,977
71	TOTAL Construction (Total of lines 68 thru 70)	1,218,734,995		1,218,734,995
72	Plant Removal (By Utility Departments)			
73	Electric Plant	44,162,540		44,162,540
74	Gas Plant	13,723,697		13,723,697
75	Other (provide details in footnote):	528,399		528,399
76	TOTAL Plant Removal (Total of lines 73 thru 75)	58,414,636		58,414,636
77	Other Accounts (Specify, provide details in footnote):			
78	Other Balance Sheet Salaries and Wages	9,876,814		9,876,814
79	Other Non-Operating Salaries and Wages	10,643,921		10,643,921
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	20,520,735		20,520,735
96	TOTAL SALARIES AND WAGES	3,122,828,177		3,122,828,177

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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
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COMMON UTILITY PLANT IN SERVICE

Acct No.	Description	Balance Beginning of Year	Additions	Retirements	Transfers and Adjustments	Balance End of Year
301	Organization	138,760	2,930,378	0	-2,839,675	229,463
302	Franchises/Consents	214,735	0	0	0	214,735
303	Intangible Plant	1,538,201,610	338,777,885	-108,487,622	0	1,768,491,873
	Total Intangible Plant	1,538,555,105	341,708,263	-108,487,622	-2,839,675	1,768,936,071
389	Land and Land Rights	84,050,843	7,852	0	0	84,058,695
390	Structures and Improvements	1,335,314,896	97,615,662	-8,905,349	32,745	1,424,057,954
391	Personal Computer Hardware	117,575,766	21,121,692	-24,533,459	0	114,163,999
391	Office Machines	293,504,903	71,715,775	-13,169,257	2,802,402	354,853,823
391	Office Furniture and Equipment	108,725,899	6,846,826	-8,400,044	4,528	107,177,209
392	Transportation Equipment	936,186,173	114,246,528	-95,241,739	0	955,190,962
393	Stores Equipment	7,780,489	521,297	0	0	8,301,786
394	Tools, Shop, and Garage Equipment	63,367,086	3,697,923	100,000	0	67,165,009
395	Laboratory Equipment	11,563,453	29,720	-494,831	0	11,098,342
396	Power Operated Equipment	141,138,299	8,879,538	-8,656,853	0	141,360,984
397	Communication Equipment	994,708,580	113,119,697	-21,782,706	3,823,563	1,089,869,134
398	Miscellaneous Equipment	26,491,908	-2,192,524	-956,591	0	23,342,793(a)
399	Other Tangible Property	39,629	0	-1,204	0	38,425
	Total Non-Landed	4,036,397,081	435,602,134	-182,042,033	6,663,238	4,296,620,420
	Total	5,659,003,029	777,318,249	-290,529,655	3,823,563	6,149,615,186
101	Property Under Capital Leases	19,441,789	0	0	-605,534	18,836,255
101	Plant Purchased/Sold	0	0	0	432,678	432,678
	Total Common Utility Plant in Service	5,678,444,818	777,318,249	-290,529,655	3,650,707	6,168,884,119

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107 Construction Work in Progress - Common Utility Plt.	338,357,403	-54,144,679	0	-7,609,249	276,603,475
Total Common Utility Plant	6,016,802,221	723,173,570	-290,529,655	-3,958,542	6,445,487,594

NOTES:
(a) Included in the 12/31/15 FERC account 398 plant balance is $6,999,296 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)	6,168,884,119	4,141,340,508	2,027,543,611
Accumulated Provision for Depreciation (a)	2,328,295,113	1,508,036,745	820,258,368

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)	347,534,328	278,164,078	69,370,250
Common Utility Plant (a) included in above amount	25,621,695	17,200,544	8,421,151

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NOTES:

(a) 2015 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	67.13%	32.87%
Common Plant Accumulated Depreciation Allocation Factors	64.77%	35.23%

(b) Amounts are based on direct charges. Not included in the total was $344,953 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	203,122,588	131,562,500	71,560,088
Amortization	404	278,756,074	180,550,309	98,205,765
Total		481,878,662	312,112,809	169,765,853

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

Description	Amount Charged During Year	Account 935 Electric	Account 935 Gas
Maintenance of General Plant	13,568,617	9,774,832	3,793,785

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     Note:   Operation expense data was not available.


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

  Description of Project                                   Amount
  -----------------------------------------              ----------
  70027169    NCV5 System Resiliency Common-C     19,948,585
  70027370    SAP DR      9,536,950
  70029189    CC&B Infrastructure Hardware        9,005,080
  70025765    Flexera - Software Purchase     7,172,366
  70026861    Enterprise PPM: IT      5,328,099
  70019523    Trans Outtage Mgmt System (Cap)     5,182,746
  7081085 Helms Microwave Replacement     5,065,819
  70029603    Cloud Enablement ~ Hardware     4,643,882
  70026912    MPLS Tier-1 Expansion Phase 2       4,591,734
  7086132 FFIOC-Security ControlCenter Remodel Cap        4,328,557
  70025202    IAM - PriorityAppsIntegration&AccessCert        4,074,637
  70028386    CIP 002 WP 2  IT/OT Asset Management Con        3,983,971
  70025290    DR - Distribution Managment System (DMS)        3,602,484
  7084411 Concord SC- Repl Pavement & UG Utilities        3,480,111
  7086966 IT Costs: $2.7M IDA Phase 3     3,224,881
  70021400    MobileConnect for ET Compliance     2,873,829
  7082926 Edenvale SC - Replace Asphalt/Gate      2,871,143
  70028660    FMO FAS ITRON CAP       2,828,413
  7086705 Verint - Capital        2,809,397
  70026971    BPC Upgrade to 10.x (EoL 3/2017)        2,571,277
  70025382    Estimating Work Management (Cap) - ED       2,430,343
  70030060    CoC Reporting - ED&M CAP Ph 2       2,408,903
  70027762    Workstream-2: UCCE Upgrade Workstream CA        2,396,579
  7084857 63-GCC Facility Expansion: IT       2,342,247
  70025720    NCv5 FAM Integration (NERC scope)       2,292,380
  7086029 Willows SC - Renovation     2,271,320
  70028847    Datacenter Capacity Growth-Storage Ph2      2,190,564
  7082866 San Carlos SC - Replace HVAC Units      2,088,830
  70027368    NEMS Web Portal (Ph 2) - Capital        1,916,723
  7087346 PGE.COM Accessibility Redesign - CAP        1,907,186
  7087386 Vacaville Critical Operations Campus        1,836,835
  7086967 IT Costs: $500K Reg Affairs Ops     1,750,716
  70026620    IT PM Tools Improvement Release 3 - Prim        1,660,759
  7087285 77 Beale, B1 - IT Office Space Remodel      1,633,777
  70026843    CIP003-WP01-v9-Documentum  C        1,612,852
  70026967    Legal Best Practice Alignment       1,609,473
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70028682    Verint LC Replace v11 Enterprise App        1,584,302
7087825 Enterprise Network Operations Center        1,574,868
70022104    DMS (GIS&SchemaConsolidation)-PostDMS7.2        1,571,401
70029224    Endur Power Release 2 Wave 2        1,507,254
70027380    Radio Reliability - Coverage Availabilit        1,504,616
70029800    DWDM Replacement Phase 3 (Northern Fiber        1,492,890
70029441    ST-Non-Employee Workforce Security - Cap        1,459,529
7083919 Stockton Sta A MW Capacity Increase     1,450,033
7085246 2014 ET SCADA Server Lifecycle Replace      1,420,892
70024104    DR - Set 0:  ESFT       1,414,540
70027594    IO-Datacenter Network Stabilization     1,407,469
7085045 215 Market Annex-Window  Replacement        1,398,213
7085905 45 Beale,Aud-Replace Air Handlers S1/S5     1,376,768
70029193    iSAP RegLearn       1,375,525
70026855    CIP005-WP03-B-Interactive Remote Acces C        1,368,752
7082405 New Castle PH to Auburn SC Fiber Replace        1,352,228
70027222    Endur - MCRM Data Integration CAP       1,346,823
7085185 Electric Master SCADA Power Systems Upgr        1,324,699
7087505 San Ramon Techn Ctr - Renovation (S&I)      1,293,648
70026906    CIP010-WP01-ODN TEST Environment        1,275,821
7087508 GD GIS Enhancments      1,261,408
70028043    ET GIS Enhancement Efforts (Cap)        1,213,180
70028663    CSD Online Bill Payment and Contract Exe        1,208,436
70029487    2015 Oracle DB_Audit Rem & Data Sec Enh     1,202,638
70027048    Gas Ops Radio System Phase 3 (CAP)      1,199,266
70027401    ESOMS Upgrade CAP       1,157,409
70025293    DR - Network:  DCPP     1,151,404
70024520    Meter Asset Mgmt App Upgrade CAP        1,141,167
70028282    CIP004-WP11-E Logical Access Mgmt-C     1,129,190
7084547 Hydro SCADA OSI Update to Win7/Win 2008     1,104,667
70026908    CIP010-WP02-A-Tripwire Configuration MgC        1,102,251
70025042    Estimating Work Management (Cap) - GD       1,097,022
7086842 SG LS Ph2 - IT - Tollgrade      1,084,394
7088126 G.O. - Carpet Replacement on Four Floors        1,043,885
70024901    Foundational Project - Drum     1,039,002
70027780    ST-IAM-Ident and Access Rev Imprments-CA        988,211
7086555 SG VVO Ph2 - Adv Func - PM      980,037
7085666 Radio Reliability - Hwy 50      968,742
7086846 SG LS Ph2 - IT - Vendor Tollgrade       921,823
70026853    CIP005-WP08-B-ESP Phase 2  (Cap)        906,587
70028040    Asset Health Solution       898,487
7088067 Fresno Ctr Ofc Improvements (S&I)       896,070
70026867    Estimating Work Management (Cap) - GD       895,401
70028905    DR - IT Core: AD/CA/RM      887,645
70027820    SIP Trunk and PRI RFP - Cap     852,912
70028800    LOTO - (Cap)        847,510
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70026847	CIP004-WP02-A-PAPM- ODN (Cap)	843,912
7084408	77 Beale-Replace Chiller Pumps 1,2,3,4	835,984
7087585	SRTC-East Side Parking Laydown Expansion	835,566
70026870	Bandwidth Capacity Imp-Cupertino SC	835,378
70025846	NERC CIP V5 Fast 007	815,754
7085688	Oakland SC - Asphalt Replacement	769,292
7086925	Central DCC 2015 Cap Improvements	767,205
7083999	Leased VF DS0 Retire Central-San Jose	755,398
7086845	SG LS Ph2 - IT - Vendor Sentient	752,403
70027221	Replace REMS with OpenEMS	748,270
70028460	Endur Platform - GHG - Gas Emissions CAP	746,544
70028902	DR - IT Core: DNS / DHCP	731,746
7085907	Webcast Studio	720,643
70021449	MobileConnect Maint <(>&<)> Constr T-200	716,328
70024280	Helms Cabling Refresh 2014: Wireless Ac	713,679
70027581	IO-DC Network Upgrades-Load Balancing	706,674
70021631	AO SAP Rearchitecture CAP)	702,138
7087176	SG FDL Ph2 - IT - General	668,328
70029267	(ODMS) Phase 2 Capital Work	653,561
70027590	EMC NAS NS960 Lifecycle Migration	653,042
7088132	FFIOC - Critical Operations Equipment	652,938
70026892	CIP007-WP04-E-Windows Malicious Code C	652,422
70027104	DCPP Wireless Application Phase 2	649,639
7087511	Antioch SC - Construct New Ofc/Storage	640,341
7084047	Leased VF DS0 Retire South-SLO SC	637,909
7086839	SG LS Ph2 - IT - General	622,094
70024361	DCPP Unit 1 IT Containment Infrastructur	621,317
7086841	SG LS Ph2 - IT - Sentient	608,636
70029581	EMS SMP Server Replacement	606,298
7086212	77 Beale,4th-Fans S6,S7,S11,S12 Upgrade	587,633
7086365	Fremont MDF- Construct Materials Whse.	583,561
70027880	Fall 2015 Release	582,168
7085005	General Office - Replace 7 ATS	579,097
70028360	Ventyx upgrade (9.1 to 9.3 Migration) (C	578,515
70029378	ADSO Training Simulator Upgrade (Cap)	574,991
70026300	CC&B DR Plan/Analyze	570,623
70025281	DR - Network: Gateway of Last Resort	570,571
7083992	Leased VF DS0 Retire North-Eureka SC	561,802
7086328	Merced SC - Construct New Office/Storage	556,532
7084267	Sycamore Creek SPCC Modifications	555,781
7085486	Fresno Gas Load Center - GC Upgrade	546,869
7084485	45Beale,B1 Repro-Repl.Air Handlers S2/S3	536,797
70024461	I&O AO Database Lifecycle Upgrade 2014	531,202
70028963	ET&S Contract Forecast Mgmt (Cap)	526,919
70028903	DR - IT Core: NTP Time Protocol / Stratu	526,426
7083846	Level 3 Lateral Builds	520,502

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7086211	CA Facilities Upgrade - Capital	512,787
7084551	Leased VF DS0 Retire South-Bakersfield S	501,979
70029809	IO - DWDM Replacement Phase 3 (Northern	500,179
70029406	Tableau Labor -Capital	497,962
7084557	ACME Packt SBC (Session Border Cntrller)	487,771
70028741	PGEN Linear Asset Management -Capital	480,707
70027800	ST-IAM Position Based Acc Prov Ph1 IT -	469,497
70026904	CIP009-WP01-v22-Continuity ManagementSyC	465,385
7086207	General Office - Replace Four ATS (2015)	464,756
70028383	CyberSecu-Monitor Security - GTS	464,074
7086665	SRVCC - Master Planning	458,283
70022520	Bentley-SAP Integration CAP ET	456,362
70026660	Pole Loading Tool Upgrade with Industry	454,734
70028021	LAND Library Migration	454,052
7087531	SFSC-Emergency Ctr Upgrades EMAP (S&I)	450,436
7087425	Control Room Predictive Tools	448,732
70026963	Bandwidth Capacity Imp-Eureka SC	433,002
7087687	77 Beale-Electric Distribution Sys.Repl.	430,211
7083651	Radio Rel - Crane Valley PH (Bass Lake)	420,880
7087512	Auburn Regional Consolidation	420,761
70026900	CIP008-WP02-G-Incident ResponsePROCESS C	419,622
7086405	Manteca SC - Connect to Municipal Water	409,696
7088125	Burney Comp Station-Site Improvements	407,678
7088066	SG FDL Ph2 -IT Vendor Tollgrade	406,486
7084555	Wireless Broadband Pilot Deployment	401,819
70027388	2015 Channel Bank Lifecycle	396,675
7086285	System-Repl.Fire&Life Safety Panels2014	393,323
70028462	Control Room Predictive tools Dist (Cap)	388,092
7083234	SG Fault Location Ph1 IT - Bus Tech/Apps	379,508
7088405	Gas Ops Radio Project	379,065
70026140	Gas Storage Asset Mgmt - (CAP)	378,913
7087105	Gregg Sub - Drinking Water System	377,543
7084187	Leased VF DS0 Circuit Retire-Misc Ckts	376,380
7085665	Radio Reliability - Hwy 12 & 29 Radio Co	374,156
70026841	IT Facility Improvement Project-Richmond	369,431
7086165	Radio Reliability - Area 23A	362,665
7084945	G.O.-Power Quality Monitoring System	358,233
7085247	2014 ED SCADA Server Lifecycle Replace	351,444
7083180	SG Line Sensors Ph1 IT - Bus Tech/Apps	348,693
7082786	SG Fault Location Ph1 IT - PM	346,794
7084548	Radio Reliability - Point Sur	339,870
7088089	VCOC - IT Infrastructure	338,444
70028521	Garrettcom Switch Replacements-Ph. 2	333,503
70021821	SAP Rearchitecture - I&O Ops Labor (CAP)	331,214
7074466	*Clayton Hill to CDWR Microwave	330,328
70026886	CIP006-WP04-B-Window Barrier Install C	315,401

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COMMON UTILITY PLANT AND EXPENSES

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

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70028384    CyberSecu-Asset Change Mgmt-Gas Trans C     312,755
7085846 PBX Replacement-DeSabla Watershed       309,239
70028060    TOTL LOB Training - New Tool & Testing (        300,958
7085346 77 Beale Lobby-Upgrades & Improvements      292,924
70025240    Foundational Project - Fresno Operations        290,708
7084003 Leased VF DS0 Retire North-Fairfield SC     289,733
7084285 SIP Trunk Services Phase 2      288,910
7084046 Leased VF DS0 Retire Central-Salinas SC     287,140
70026840    IT Facility Improvement Project-Vallejo     283,929
7084009 Urbanet 10GHz MW Trimble Sub to Sunol Ri        283,307
7086133 FFIOC-Reactive Load Bank Cooling Upgrade        281,010
70025843    NERC CIP V5 Fast 004        276,588
7081328 Replace ISO Metering Stations Routers/Fi        273,890
70028843    Windows Remote Field Servers Ph. 4      273,181
7083729 TO Radio System Expansion - Gato Ridge      268,041
7085668 Radio Reliability - GOS Sites Upgrade       266,321
70027300    Bandwidth Capacity Improvements     261,013
7088005 North DCC Post-Build Improvements       255,993
70029782    GeoMart Distribution - Cap      255,322
70029783    GeoMart Transmission - Cap      253,679
7088326 Auburn Regional Consolidation-Bldg.Purch        250,819

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

Subtotal - Projects with more than $250,000
  in actual costs in CWIP, excluding Research,
  Development, & Demonstration jobs                       $250,048,881
Projects with less than $250,000 in actual
  costs to CWIP, including credits representing
  preliminary bilings                                       26,554,594
                                                           ------------
    TOTAL CWIP - COMMON                               $276,603,475
                                                          =============
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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	02/24/2016	End of 2015/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)	126,554,398	135,530,103	247,928,282	710,782,267
3	Net Sales (Account 447)	(14,610,841)	9,503,579	(9,762,986)	(17,342,410)
4	Transmission Rights				
5	Ancillary Services	1,420,904	94,782	305,762	2,799,986
6	Other Items (list separately)				
7	Grid Management Charges	12,448,958	14,229,278	15,876,976	55,407,687
8	FERC Fees	1,171,271	1,221,680	1,632,770	4,751,441
9	ISO Congestion				
10	Unaccounted for Energy	30,263,677	16,759,550	(9,979,152)	23,766,381
11	Congestion Revenue Rights-Hedge	(5,632,825)	(26,001,645)	(17,066,336)	(52,257,090)
12	Congestion Revenue Rights-Auction	1,568,241	247,894	669,373	4,402,121
13	Convergence Bidding	(419,305)	593,378	(1,244,347)	(1,098,245)
14	Other ISO-related charges:				
15	Minimum Load				
16	Neutrality	704,206	833,703	(1,519,645)	10,435
17	Voltage Support				
18	Other	(5,335,686)	(763,860)	5,832,201	1,189,214
19	Cost Recovery	939,946	(2,359,168)	(627,647)	(1,257,328)
20	Inter Day Ahead SC Trade				
21	Inter Real Time SC Trade				
22	Interest	66,896	288,546	24,079	567,553
23	Capacity - Other	(957,529)	3,864,662	(1,302,178)	3,589,430
24	DA IFM Credit Allocation	(9,876,656)	(12,959,827)	(17,502,214)	(51,980,196)
25	RT Offset/Allocation	(383,132)	11,724,209	12,461,518	30,175,480
26	Net Purchases for Energy Storage	32,993	33,298	13,974	85,614
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	137,955,516	152,840,162	225,740,430	713,592,340

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch					N/A	246,000
2	Reactive Supply and Voltage				723,176	kW-Month	148,251
3	Regulation and Frequency Response				696,945	kW-Month	27,878
4	Energy Imbalance				803,568	kWh	80,357
5	Operating Reserve - Spinning				696,945	kW-Month	150,749
6	Operating Reserve - Supplement				696,945	kW-Month	149,530
7	Other		Various	6,621,771		Various	3,821,786
8	Total (Lines 1 thru 7)			6,621,771	3,617,579		4,624,551

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

With the exception of the Utility's contract with BART (OAT Tarriff) that is reported In Lines 1 - 6, all Ancillary Services (AS) purchases and sales are covered under the FERC approved ISO Tariff. Definitions of AS under Order No. 888 and the ISO Tariff are not consistent with one another. In order to avoid confusion as to meanings and terminologies, ISO AS amounts are not included on these lines but are reported on Line 7.

For BART there is no billing determinate for Scheduling, System Control and Dispatch. The monthly charge is a flat rate.

Schedule Page: 398 Line No.: 8 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	6,621,771	-	Various	3,821,786
Total			6,621,771			3,821,786

(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	02/24/2016	End of 2015/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	13,535	5	1900	10,292	61		113		3,069
2	February	13,507	12	1900	9,900	67		171		3,368
3	March	13,667	26	2100	9,635	46		146		3,840
4	Total for Quarter 1				29,827	174		430		10,277
5	April	14,906	30	1800	11,133	69		213		3,492
6	May	14,500	1	1700	11,182	65		187		3,066
7	June	20,422	30	1800	15,738	73		194		4,416
8	Total for Quarter 2				38,053	207		594		10,974
9	July	20,159	29	1800	15,505	74		74		4,506
10	August	20,334	17	1800	15,530	77		79		4,648
11	September	19,968	9	1800	15,159	65		81		4,663
12	Total for Quarter 3				46,194	216		234		13,817
13	October	16,639	13	1700	12,781	73		10		3,775
14	November	14,071	30	1900	10,787	68		63		-30
15	December	14,343	14	1900	11,784	68		39		861
16	Total for Quarter 4				35,352	209		112		4,606
17	Total Year to Date/Year				149,426	806		1,370		39,674

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	02/24/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 10 Column: e

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

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

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

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

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

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

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

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

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

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

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

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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	6,887,007
4	Nuclear	18,501,463
5	Hydro-Conventional	4,512,861
6	Hydro-Pumped Storage	474,034
7	Other	738,985
8	Less Energy for Pumping	740,143
9	Net Generation (Enter Total of lines 3 through 8)	30,374,207
10	Purchases	49,974,000
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	1,322,257
17	Delivered	1,305,218
18	Net Transmission for Other (Line 16 minus line 17)	17,039
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	80,365,246
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	86,167,420
23	Requirements Sales for Resale (See instruction 4, page 311.)	1,813,603
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	-7,615,777
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	80,365,246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	6,212,730		12,168	5	1900
30	February	5,552,742		12,059	17	1900
31	March	6,205,844		12,346	26	2100
32	April	6,139,324		13,537	30	2100
33	May	6,475,188		13,069	1	1700
34	June	7,454,418		18,631	30	1800
35	July	7,938,860		18,367	29	1800
36	August	7,856,401		18,563	17	1800
37	September	7,138,015		18,200	9	1800
38	October	6,619,561		15,015	13	1700
39	November	5,937,930		12,674	30	1900
40	December	6,834,234		13,339	14	1900
41	TOTAL	80,365,247				

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

Actual purchases from pages 326-327 were 44,837,023 MWH. For purposes only of accounting for the total energy that went through the Utility's electric system, the MWH for Direct Access ("DA") of 13,381,848 MWH and California Department of Water Resources ("DWR") deliveries of 2,728 MWH were added to this line item. 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	02/24/2016	End of 2015/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	8760			7528		
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	1427			25		
12	Net Generation, Exclusive of Plant Use - KWh	18501463280			3571839682		
13	Cost of Plant: Land and Land Rights	22726560			7814695		
14	Structures and Improvements	1036743265			114782340		
15	Equipment Costs	6461089858			535736867		
16	Asset Retirement Costs	780875161			3912558		
17	Total Cost	8301434844			662246460		
18	Cost per KW of Installed Capacity (line 17/5) Including	3573.5837			930.7751		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	126705233			66083754		
21	Coolants and Water (Nuclear Plants Only)	31444865			0		
22	Steam Expenses	44671316			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2199280			4675337		
26	Misc Steam (or Nuclear) Power Expenses	151627830			2890441		
27	Rents	0			0		
28	Allowances	0			30408866		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	2228588			1972590		
31	Maintenance of Boiler (or reactor) Plant	34566278			2365461		
32	Maintenance of Electric Plant	41314819			5034711		
33	Maintenance of Misc Steam (or Nuclear) Plant	64002629			24516394		
34	Total Production Expenses	498760838			137947554		
35	Expenses per Net KWh	0.0270			0.0386		
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	2324294	0	0	24695930	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1036500	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	3.440	0.000	0.000
41	Average Cost of Fuel per Unit Burned	54.106	0.000	0.000	3.530	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.661	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	10287.814	0.000	0.000	7.166	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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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	02/24/2016	End of 2015/Q4

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

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

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

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
7577			8498			0			7
0			0			0			8
0			0			0			9
0			0			0			10
21			17			0			11
3315167748			406338842			0			12
5040000			161399			0			13
72280344			66889026			0			14
374296405			147340450			0			15
3004029			1925852			0			16
454620778			216316727			0			17
733.6143			1329.5435			0			18
0			0			0			19
60910318			13948664			0			20
0			0			0			21
333204			0			0			22
0			0			0			23
0			0			0			24
3499342			4044386			0			25
2920046			1993587			0			26
0			0			0			27
30408866			9329594			0			28
0			0			0			29
338160			315528			0			30
1765198			59162			0			31
4151007			4367435			0			32
315394			11156			0			33
104641535			34069512			0			34
0.0316			0.0838			0.0000			35
Gas			Oil	Gas					36
Mcf			Bbl	Mcf					37
22914085	0	0	4250	3508941	0	0	0	0	38
1037750	0	0	5731884	1037000	0	0	0	0	39
3.440	0.000	0.000	81.270	3.430	0.000	0.000	0.000	0.000	40
3.540	0.000	0.000	119.240	3.750	0.000	0.000	0.000	0.000	41
3.410	0.000	0.000	20.800	3.610	0.000	0.000	0.000	0.000	42
0.020	0.000	0.000	0.180	0.030	0.000	0.000	0.000	0.000	43
7173.000	0.000	0.000	8777.000	9102.000	0.000	0.000	0.000	0.000	44

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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

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

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

Plant Name: (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

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	02/24/2016	End of 2015/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
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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	02/24/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 1 (b)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1927	1958
4	Year Last Unit was Installed	1927	1958
5	Total installed cap (Gen name plate Rating in MW)	31.00	97.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	105
7	Plant Hours Connect to Load	4,989	6,365
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	19,305,522	51,608,550
13	Cost of Plant		
14	Land and Land Rights	8,293	2,553
15	Structures and Improvements	143,796	3,272,306
16	Reservoirs, Dams, and Waterways	9,517,476	6,619,286
17	Equipment Costs	9,693,147	31,407,743
18	Roads, Railroads, and Bridges	1,117,535	1,020,293
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	20,480,247	42,322,181
21	Cost per KW of Installed Capacity (line 20 / 5)	660.6531	435.4134
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	1,960	6,052
25	Hydraulic Expenses	31,128	97,145
26	Electric Expenses	398,805	1,244,962
27	Misc Hydraulic Power Generation Expenses	175,197	548,708
28	Rents	7,886	24,353
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	149,482	505,019
31	Maintenance of Reservoirs, Dams, and Waterways	90,523	654,970
32	Maintenance of Electric Plant	482,533	935,950
33	Maintenance of Misc Hydraulic Plant	106,474	77,542
34	Total Production Expenses (total 23 thru 33)	1,443,988	4,094,701
35	Expenses per net KWh	0.0748	0.0793

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2105 Plant Name: BUTT VALLEY (b)	FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1921
4	Year Last Unit was Installed	1958	1924
5	Total installed cap (Gen name plate Rating in MW)	40.00	73.85
6	Net Peak Demand on Plant-Megawatts (60 minutes)	41	75
7	Plant Hours Connect to Load	6,866	5,173
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	73,346,779	82,182,088
13	Cost of Plant		
14	Land and Land Rights	484,414	372,342
15	Structures and Improvements	2,993,088	4,802,889
16	Reservoirs, Dams, and Waterways	37,322,966	28,831,682
17	Equipment Costs	15,552,772	24,749,900
18	Roads, Railroads, and Bridges	616,888	488,669
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	56,970,128	59,245,482
21	Cost per KW of Installed Capacity (line 20 / 5)	1,424.2532	802.2408
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	17,578	32,190
25	Hydraulic Expenses	17,920	32,847
26	Electric Expenses	287,748	1,587,493
27	Misc Hydraulic Power Generation Expenses	301,821	552,564
28	Rents	1,916	3,503
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	26,278	195,732
31	Maintenance of Reservoirs, Dams, and Waterways	371,804	237,090
32	Maintenance of Electric Plant	175,817	362,369
33	Maintenance of Misc Hydraulic Plant	39,205	151,464
34	Total Production Expenses (total 23 thru 33)	1,240,087	3,155,252
35	Expenses per net KWh	0.0169	0.0384

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
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3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 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	6,572	1,184
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	42,821,962	20,917,221
13	Cost of Plant		
14	Land and Land Rights	147,350	1,473,193
15	Structures and Improvements	2,735,656	5,204,659
16	Reservoirs, Dams, and Waterways	39,346,998	36,353,238
17	Equipment Costs	5,443,596	17,449,098
18	Roads, Railroads, and Bridges	2,278,937	1,123,030
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,952,537	61,603,218
21	Cost per KW of Installed Capacity (line 20 / 5)	2,707.4546	1,252.0979
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	5,741	43,379
25	Hydraulic Expenses	82,620	396
26	Electric Expenses	460,237	2,141,586
27	Misc Hydraulic Power Generation Expenses	501,095	731,349
28	Rents	3,379	18,128
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	176,564	264,443
31	Maintenance of Reservoirs, Dams, and Waterways	922,400	472,068
32	Maintenance of Electric Plant	67,573	338,627
33	Maintenance of Misc Hydraulic Plant	88,496	254,343
34	Total Production Expenses (total 23 thru 33)	2,308,105	4,264,319
35	Expenses per net KWh	0.0539	0.2039

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1988 Plant Name: HAAS (b)	FERC Licensed Project No. 2130 Plant Name: HALSEY (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1958	1916
4	Year Last Unit was Installed	1958	1916
5	Total installed cap (Gen name plate Rating in MW)	135.00	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	144	11
7	Plant Hours Connect to Load	5,204	4,236
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	35,180,222	14,611,674
13	Cost of Plant		
14	Land and Land Rights	28,175	986,205
15	Structures and Improvements	7,914,835	2,239,071
16	Reservoirs, Dams, and Waterways	27,574,341	26,265,250
17	Equipment Costs	23,419,073	6,920,937
18	Roads, Railroads, and Bridges	150,159	77,211
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	59,086,583	36,488,674
21	Cost per KW of Installed Capacity (line 20 / 5)	437.6784	2,682.9907
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	8,302	8,840
25	Hydraulic Expenses	131,816	17
26	Electric Expenses	937,036	610,704
27	Misc Hydraulic Power Generation Expenses	789,778	164,812
28	Rents	137,044	3,694
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	178,525	25,141
31	Maintenance of Reservoirs, Dams, and Waterways	449,399	875,302
32	Maintenance of Electric Plant	733,861	156,250
33	Maintenance of Misc Hydraulic Plant	116,474	111,086
34	Total Production Expenses (total 23 thru 33)	3,482,235	1,955,846
35	Expenses per net KWh	0.0990	0.1339

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 96 Plant Name: KERCHKOFF 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	2,533	2,001
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	78,031,010	15,298,000
13	Cost of Plant		
14	Land and Land Rights	584,350	17,679
15	Structures and Improvements	37,963,314	3,127,989
16	Reservoirs, Dams, and Waterways	77,010,648	20,564,944
17	Equipment Costs	40,374,528	10,942,610
18	Roads, Railroads, and Bridges	7,534,642	42,833
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	163,467,482	34,696,055
21	Cost per KW of Installed Capacity (line 20 / 5)	1,171.8099	713.9106
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	190,811	2,997
25	Hydraulic Expenses	141,901	47,592
26	Electric Expenses	1,020,631	372,103
27	Misc Hydraulic Power Generation Expenses	850,184	267,362
28	Rents	20,568	49,487
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	108,030	32,389
31	Maintenance of Reservoirs, Dams, and Waterways	408,975	111,469
32	Maintenance of Electric Plant	2,456,931	426,145
33	Maintenance of Misc Hydraulic Plant	433,665	40,676
34	Total Production Expenses (total 23 thru 33)	5,631,696	1,350,220
35	Expenses per net KWh	0.0722	0.0883

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 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	8,308	7,311
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	237,704,290	229,979,077
13	Cost of Plant		
14	Land and Land Rights	3,820,305	315,079
15	Structures and Improvements	6,876,163	2,053,031
16	Reservoirs, Dams, and Waterways	60,750,255	40,551,897
17	Equipment Costs	21,439,003	22,886,970
18	Roads, Railroads, and Bridges	7,488,026	3,943,560
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	100,373,752	69,750,537
21	Cost per KW of Installed Capacity (line 20 / 5)	1,251.6991	673.9182
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	41,094	47,981
25	Hydraulic Expenses	17,583	23,871
26	Electric Expenses	1,950,645	492,925
27	Misc Hydraulic Power Generation Expenses	1,321,760	1,553,667
28	Rents	3,704	5,026
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	46,644	33,569
31	Maintenance of Reservoirs, Dams, and Waterways	285,224	163,889
32	Maintenance of Electric Plant	404,841	1,291,172
33	Maintenance of Misc Hydraulic Plant	173,027	166,989
34	Total Production Expenses (total 23 thru 33)	4,244,522	3,779,089
35	Expenses per net KWh	0.0179	0.0164

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
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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	7,374	6,658
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	225,750,636	192,983,247
13	Cost of Plant		
14	Land and Land Rights	820,603	1,777,598
15	Structures and Improvements	8,813,682	4,407,753
16	Reservoirs, Dams, and Waterways	38,968,944	42,691,544
17	Equipment Costs	27,172,613	102,518,168
18	Roads, Railroads, and Bridges	1,146,684	353,339
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	76,922,526	151,748,402
21	Cost per KW of Installed Capacity (line 20 / 5)	538.5600	1,210.4044
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	51,476	54,069
25	Hydraulic Expenses	52,521	55,169
26	Electric Expenses	456,774	1,916,730
27	Misc Hydraulic Power Generation Expenses	734,852	1,457,363
28	Rents	8,534	9,790
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	62,587	184,849
31	Maintenance of Reservoirs, Dams, and Waterways	498,842	440,587
32	Maintenance of Electric Plant	232,307	514,422
33	Maintenance of Misc Hydraulic Plant	551,846	97,824
34	Total Production Expenses (total 23 thru 33)	2,649,739	4,730,803
35	Expenses per net KWh	0.0117	0.0245

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 137 Plant Name: WEST POINT (b)	FERC Licensed Project No. 2310 Plant Name: WISE NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1948	1917
4	Year Last Unit was Installed	1948	1917
5	Total installed cap (Gen name plate Rating in MW)	13.60	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	15	14
7	Plant Hours Connect to Load	7,026	7,191
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	37,963,244	36,243,907
13	Cost of Plant		
14	Land and Land Rights	156,685	803,651
15	Structures and Improvements	681,413	3,988,388
16	Reservoirs, Dams, and Waterways	5,557,720	16,236,792
17	Equipment Costs	6,525,917	8,600,539
18	Roads, Railroads, and Bridges	139,648	82,041
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	13,061,383	29,711,411
21	Cost per KW of Installed Capacity (line 20 / 5)	960.3958	2,184.6626
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	10,794	11,240
25	Hydraulic Expenses	4,499	11
26	Electric Expenses	285,463	1,959,980
27	Misc Hydraulic Power Generation Expenses	184,463	209,932
28	Rents	11,127	4,697
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	12,950	30,965
31	Maintenance of Reservoirs, Dams, and Waterways	139,627	909,808
32	Maintenance of Electric Plant	201,198	149,185
33	Maintenance of Misc Hydraulic Plant	68,379	157,998
34	Total Production Expenses (total 23 thru 33)	918,500	3,433,816
35	Expenses per net KWh	0.0242	0.0947

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	02/24/2016	End of 2015/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
3,922	8,563	7,156	7
			8
125	172	65	9
125	172	53	10
0	0	0	11
142,912,134	398,102,126	79,157,289	12
			13
539,304	642,173	810,578	14
5,025,829	717,660	1,113,536	15
56,902,106	64,695,310	18,808,750	16
21,053,918	17,750,624	19,928,675	17
474,271	2,081,581	3,085,588	18
0	0	0	19
83,995,428	85,887,348	43,747,127	20
712.4294	509.2337	662.8353	21
			22
0	0	0	23
53,632	76,347	34,323	24
54,722	45,371	28,444	25
462,721	816,357	321,782	26
1,295,466	1,543,882	789,006	27
5,838	17,057	20,809	28
0	0	0	29
74,547	70,552	32,638	30
283,450	343,993	229,481	31
404,459	728,569	339,039	32
192,219	231,727	124,143	33
2,827,054	3,873,855	1,919,665	34
0.0198	0.0097	0.0243	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	02/24/2016	End of 2015/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
6,329	6,482	8,714	7
			8
120	13	70	9
119	5	72	10
0	0	0	11
220,740,977	26,893,816	124,141,762	12
			13
344,839	185,911	1,364,682	14
6,172,601	1,681,445	1,790,601	15
30,407,669	23,506,152	20,998,555	16
18,109,841	13,090,742	10,985,135	17
15,362	1,198,687	135,058	18
0	0	0	19
55,050,312	39,662,937	35,274,031	20
466.9238	3,264.4393	477.9679	21
			22
0	0	0	23
51,466	678	30,034	24
52,521	64,270	30,646	25
774,336	166,708	360,420	26
883,819	252,975	809,597	27
5,605	1,149	5,438	28
0	0	0	29
102,803	33,148	43,367	30
588,806	312,609	216,819	31
362,732	455,901	372,148	32
522,796	95,538	58,831	33
3,344,884	1,382,976	1,927,300	34
0.0152	0.0514	0.0155	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2310 Plant Name: DRUM NO. 2 (d)	FERC Licensed Project No. 2310 Plant Name: DUTCH FLAT (e)	FERC Licensed Project No. 137 Plant Name: ELECTRA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1965	1943	1948	3
1965	1943	1948	4
53.10	22.00	102.50	5
50	22	98	6
7,330	7,438	7,222	7
			8
50	22	98	9
49	23	98	10
0	0	2	11
175,386,413	62,567,107	164,186,776	12
			13
315,248	749,920	749,994	14
761,578	1,966,545	1,325,151	15
8,879,956	17,503,957	23,294,375	16
4,149,414	13,268,304	22,975,287	17
382,275	241,752	891,437	18
0	0	0	19
14,488,471	33,730,478	49,236,244	20
272.8526	1,533.2035	480.3536	21
			22
0	0	0	23
39,765	17,665	248,533	24
4,816	54	30,410	25
1,484,519	622,638	1,505,201	26
670,458	297,876	1,246,754	27
16,617	7,382	75,204	28
0	0	0	29
111,361	75,724	84,186	30
418,197	183,173	945,656	31
196,230	232,739	640,541	32
245,956	103,601	462,162	33
3,187,919	1,540,852	5,238,647	34
0.0182	0.0246	0.0319	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2661 Plant Name: HAT CREEK NO. 1 (d)	FERC Licensed Project No. 2661 Plant Name: HAT CREEK NO. 2 (e)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1921	1921	1920	3
1921	1921	1920	4
10.00	10.00	22.72	5
9	9	25	6
8,476	8,476	486	7
			8
9	9	25	9
4	4	0	10
0	0	0	11
22,155,660	30,899,239	0	12
			13
762,189	729,377	7,668	14
244,335	280,602	1,566,079	15
2,769,460	1,045,277	3,260,989	16
2,865,502	3,566,637	5,801,039	17
1,176,067	393,049	6,708	18
0	0	0	19
7,817,553	6,014,942	10,642,483	20
781.7553	601.4942	468.4191	21
			22
0	0	0	23
0	0	31,269	24
2,137	2,137	23,256	25
458,833	145,671	254,501	26
312,860	312,860	139,329	27
82	82	3,371	28
0	0	0	29
1,178,033	1,293	44,797	30
38,878	98,026	119,124	31
120,872	107,337	292,660	32
49,621	27,429	76,503	33
2,161,316	694,835	984,810	34
0.0976	0.0225	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	02/24/2016	End of 2015/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
3,634	2,796	7,711	7
			8
12	12	61	9
12	0	61	10
0	0	0	11
36,316,456	10,111,705	147,083,960	12
			13
274,356	2,175,283	1,573,937	14
1,166,833	6,647,088	2,207,485	15
1,294,494	48,243,655	9,343,022	16
4,773,307	7,760,003	26,316,831	17
506,629	2,710,327	1,448,431	18
0	0	0	19
8,015,619	67,536,356	40,889,706	20
785.8450	5,317.8233	590.0390	21
			22
0	0	0	23
10,474	9,235	106,609	24
0	2	15,324	25
131,344	626,188	392,908	26
233,383	172,495	2,770,041	27
0	3,859	0	28
0	0	0	29
26,337	25,297	50,984	30
232,767	729,013	375,035	31
506,893	138,525	595,666	32
46,705	76,607	135,629	33
1,187,903	1,781,221	4,442,196	34
0.0327	0.1762	0.0302	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	02/24/2016	End of 2015/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
8,627	8,529	8,747	7
			8
160	80	112	9
160	80	112	10
6	0	0	11
443,217,447	199,847,908	272,488,579	12
			13
654,986	303,188	333,731	14
12,361,041	3,111,545	2,696,606	15
38,871,066	21,939,377	30,099,357	16
65,415,922	11,977,158	11,590,721	17
8,726,566	690,652	410,202	18
0	0	0	19
126,029,581	38,021,920	45,130,617	20
888.5334	480.0747	411.0257	21
			22
0	0	0	23
0	35,516	49,719	24
40,277	20,106	28,145	25
2,264,366	489,352	377,243	26
2,631,151	731,492	1,023,976	27
8,465	7,935	11,108	28
0	0	0	29
144,352	14,028	12,541	30
361,953	134,275	356,917	31
1,085,884	1,037,325	584,295	32
345,340	108,442	125,595	33
6,881,788	2,578,471	2,569,539	34
0.0155	0.0129	0.0094	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 137 Plant Name: SALT SPRINGS (d)	FERC Licensed Project No. 2130 Plant Name: STANISLAUS (e)	FERC Licensed Project No. 137 Plant Name: TIGER CREEK (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Outdoor	Conventional	2
1931	1963	1931	3
1953	1963	1931	4
42.03	81.90	52.28	5
44	91	58	6
4,355	5,056	7,256	7
			8
44	91	58	9
34	91	58	10
2	0	6	11
67,070,070	155,695,572	137,625,157	12
			13
244,600	299,628	2,531,110	14
1,312,293	1,130,078	5,432,943	15
31,149,774	44,514,347	46,886,541	16
12,512,444	24,979,464	14,870,362	17
1,073,927	916,372	3,172,198	18
0	0	0	19
46,293,038	71,839,889	72,893,154	20
1,101.4285	877.1659	1,394.2837	21
			22
0	0	0	23
32,748	412,668	43,175	24
13,608	49,454	21,148	25
783,458	1,158,718	1,342,771	26
559,769	2,120,090	737,853	27
33,759	31,456	44,507	28
0	0	0	29
64,277	46,125	139,868	30
717,120	685,596	838,183	31
299,707	724,887	613,219	32
95,844	529,696	299,033	33
2,600,290	5,758,690	4,079,757	34
0.0388	0.0370	0.0296	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	02/24/2016	End of 2015/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
2,351	0	0	7
			8
20	0	0	9
12	0	0	10
0	0	0	11
2,590,424	0	0	12
			13
970,272	0	0	14
1,403,497	0	0	15
48,790,637	0	0	16
4,244,579	0	0	17
29,368	0	0	18
0	0	0	19
55,438,353	0	0	20
4,331.1213	0.0000	0.0000	21
			22
0	0	0	23
16,666	0	0	24
18,316	0	0	25
353,155	0	0	26
535,670	0	0	27
28,261	0	0	28
0	0	0	29
50,565	0	0	30
167,983	0	0	31
411,212	0	0	32
14,212	0	0	33
1,596,040	0	0	34
0.6161	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	02/24/2016	End of 2015/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.
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0.00	0.00	0.00	5
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			13
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0.0000	0.0000	0.0000	21
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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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 2735 Plant Name: HELMS PUMPED STORAGE (b)
1	Type of Plant Construction (Conventional or Outdoor)	Underground
2	Year Originally Constructed	1984
3	Year Last Unit was Installed	1984
4	Total installed cap (Gen name plate Rating in MW)	1,053
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	1,050
6	Plant Hours Connect to Load While Generating	2,108
7	Net Plant Capability (in megawatts)	1,212
8	Average Number of Employees	8
9	Generation, Exclusive of Plant Use - Kwh	474,034
10	Energy Used for Pumping	740,143
11	Net Output for Load (line 9 - line 10) - Kwh	-266,109
12	Cost of Plant	
13	Land and Land Rights	755,542
14	Structures and Improvements	180,693,241
15	Reservoirs, Dams, and Waterways	440,324,902
16	Water Wheels, Turbines, and Generators	240,750,608
17	Accessory Electric Equipment	59,142,660
18	Miscellaneous Powerplant Equipment	19,661,745
19	Roads, Railroads, and Bridges	8,773,225
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	950,101,923
22	Cost per KW of installed cap (line 21 / 4)	902.2810
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	360,307
26	Pumped Storage Expenses	22,890
27	Electric Expenses	3,111,641
28	Misc Pumped Storage Power generation Expenses	2,742,876
29	Rents	40,557
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	1,337,274
32	Maintenance of Reservoirs, Dams, and Waterways	1,060,835
33	Maintenance of Electric Plant	3,100,241
34	Maintenance of Misc Pumped Storage Plant	1,539,639
35	Production Exp Before Pumping Exp (24 thru 34)	13,316,260
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	13,316,260
38	Expenses per KWh (line 37 / 9)	28.0914

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

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

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period of Report End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDROELECTRIC GENERATING PLANTS:					
2	Alta FERC No.2310	1902	1.00	1.0	2,928	13,067,649
3	Centerville FERC No.803	1904	6.40	6.4		17,556,989
4	Chili Bar FERC No.2155	1965	7.02	7.0	867	12,643,288
5	Coal Canyon	1907				3,110,194
6	Cow Creek FERC No.606	1907	1.44	1.8	4,043	3,212,833
7	Crane Valley FERC No.1354	1919	0.99	0.9	-38	18,667,475
8	Deer Creek FERC No.2310	1908	5.50	5.7	18,342	74,100,753
9	Hamilton Branch	1921	5.39	4.8	4,033	8,143,726
10	Inskip FERC No.1121	1979	7.65	8.0	15,099	17,639,567
11	Kern Canyon FERC No. 178	1921	9.54	11.5	6,539	12,343,723
12	Kilarc FERC No.606	1904	3.00	3.2	9,150	4,260,786
13	Lime Saddle	1906	2.00	2.0	4,301	14,298,530
14	Merced Falls FERC No.2467	1930	3.44	3.5	-78	5,490,064
15	Oak Flat FERC No.2105	1985	1.40	1.3	5,489	8,078,657
16	Phoenix FERC No.1061	1940	1.60	2.0	4,842	13,103,440
17	Potter Valley FERC No.77	1910	9.46	9.2	8,254	40,756,142
18	San Joaquin No. 1-A FERC No.1354	1919	0.42	0.4		37,366,917
19	San Joaquin No. 2 FERC No.1354	1917	2.88	3.2		28,013,837
20	San Joaquin No. 3 FERC No.1354	1923	4.00	4.2		30,670,288
21	South FERC No.1121	1979	6.75	7.0	19,895	16,403,936
22	Spaulding No. 1 FERC No.2310	1928	7.04	7.0	21,925	35,695,026
23	Spaulding No. 2 FERC No.2310	1928	3.70	4.4	6,450	16,061,160
24	Spaulding No. 3 FERC No.2310	1929	6.61	5.8	16,871	15,549,976
25	Spring Gap FERC No.2130	1921	6.00	7.0	25,131	11,716,655
26	Toadtown FERC No.803	1986	1.80	1.5	1,875	6,251,024
27	Tule FERC No.1333	1914	4.50	6.4	-2,389	10,039,605
28	Volta No.1 FERC No.1121	1980	8.55	9.0	23,485	17,730,189
29	Volta No.2 FERC No.1121	1981	0.95	0.9	2,759	2,784,948
30	Wise II FERC No.2310	1986	2.87	3.2	-31	13,318,077
31	Miscellaneous Minor					4,193,776
32						
33	Photo Voltaic Generating Plants:					
34	AT&T PARK SOLAR ARRAYS	2007	0.11	0.1	125	1,990,928
35	SF SERVICE CENTER SOLAR ARRAY 1 & 2	2007	0.18	0.2	246	72,959
36	Vaca Dixon Solar Station	2009	2.00	2.0	4,425	10,881,965
37	Five Points - Schindler Solar Station #1	2011	15.00	15.0	25,471	54,528,921
38	Westside - Schindler Solar Station #2	2011	15.00	15.0	28,713	48,042,279
39	Stroud Solar Station	2011	20.00	20.0	40,966	61,672,706
40	Cantua Solar Station	2012	20.00	20.0	42,547	56,243,238
41	Giffen Solar Station	2012	10.00	10.0	21,772	31,292,268
42	Huron Solar Station	2012	20.00	20.0	42,785	61,017,651
43	Gates Solar Station	2013	20.00	20.0	43,228	65,543,268
44	West Gates Solar Station	2013	10.00	10.0	22,148	35,696,705
45	Guernsey Solar Station	2013	20.00	20.0	46,157	76,993,747
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	02/24/2016	End of 2015/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	3,890	8,505,334
3	California State University East Bay	2011	1.40	1.4	10,172	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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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
12,103,817	107,413		278,744	Water		2
2,547,887	320,533		720,035	Water		3
1,745,238	488,123		275,336	Water		4
	166,134		274,350			5
2,123,495	97,802		275,637	Water		6
19,672,576	69,196		366,376	Water		7
12,508,443	308,744		1,797,014	Water		8
1,483,491	367,893		469,618	Water		9
1,722,426	349,825		855,844	Water		10
1,281,848	569,094		237,580	Water		11
6,252,102	269,941		317,587	Water		12
6,991,640	298,980		515,560	Water		13
1,591,750	265,930		207,999	Water		14
5,773,318	90,066		73,725	Water		15
7,748,602	422,852		1,128,452	Water		16
3,730,110	2,780,406		989,457	Water		17
82,388,482	52,800		232,840	Water		18
9,982,663	196,002		370,684	Water		19
7,863,978	229,588		267,942	Water		20
2,415,583	305,750		401,676	Water		21
4,170,303	308,966		523,733	Water		22
4,177,365	276,658		294,515	Water		23
2,140,948	248,297		255,323	Water		24
1,570,034	420,463		473,829	Water		25
3,373,782	255,242		186,744	Water		26
1,911,908	378,991		544,996	Water		27
1,928,350	377,322		653,138	Water		28
2,881,559	111,802		193,676	Water		29
4,530,964	191,173		269,147	Water		30
				Water		31
						32
						33
17,936,287			37,993	Solar		34
1,042,269			34,790	Solar		35
5,440,983	11,744		83,705	Solar		36
3,635,261	75,135		274,472	Solar		37
3,202,819	84,200		138,287	Solar		38
3,083,635	85,367		133,741	Solar		39
2,812,162	73,650		176,216	Solar		40
3,129,227	43,292		121,033	Solar		41
3,050,883	55,950		161,545	Solar		42
3,277,163	17,017		160,510	Solar		43
3,569,671	21,560		96,308	Solar		44
3,849,687	81,045		436,817	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	02/24/2016	End of 2015/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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
5,500,677	104,957		217,814	Natural Gas		2
4,701,886	166,439		304,430	Natural Gas		3
						4
						5
						6
				Diesel		7
				Diesel		8
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Schedule Page: 410 Line No.: 5 Column: a
No federal license required. This power plant was retired on April 1, 2013.

Schedule Page: 410 Line No.: 9 Column: a
No federal license required.

Schedule Page: 410 Line No.: 13 Column: a
No federal license required.

Schedule Page: 410 Line No.: 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	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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	16,679.90	4,536.35	378

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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	16,679.90	4,536.35	378

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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
36					TOTAL	16,679.90	4,536.35	378

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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
36					TOTAL	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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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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	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	16,679.90	4,536.35	378

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	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								
27								
28	Summary of Lines							
29	listed individually above							
30	Towers		500.00			1,326.10		
31			230.00			4,036.80	2,097.23	
32			115.00			3,081.59	1,566.60	
33			70.00			153.13	68.26	
34			60.00			187.05	133.42	
35	Poles							
36					TOTAL	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1			500.00					
2			230.00				45.54	
3			115.00			2,540.71	266.61	
4			70.00			1,475.24	27.23	
5			60.00			3,780.58	331.46	
6								
7	Other Undground		230.00					
8	Transmission Lines		115.00			93.92		
9			70.00					
10			60.00			4.78		
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	16,679.90	4,536.35	378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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)	
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/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.
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	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)	
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	36

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	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
								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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period of Report End of 2015/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.
								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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/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)	
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(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
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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	02/24/2016	End of 2015/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
								26
								27
								28
								29
	23,344,987	386,217,122	409,562,109	1,319,987	5,742,587		7,062,574	30
	62,230,253	1,466,067,517	1,528,297,770	4,018,192	17,481,091		21,499,283	31
	29,878,477	385,614,478	415,492,955	3,067,385	13,344,618		16,412,003	32
	1,598,426	18,663,674	20,262,100	152,424	663,119		815,543	33
	4,376,104	36,539,875	40,915,979	186,188	810,007		996,195	34
								35
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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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								1
								2
	44,101,911	402,489,649	446,591,560	2,528,993	11,002,353		13,531,346	3
	10,249,570	144,934,288	155,183,858	1,468,440	6,388,427		7,856,867	4
	23,306,788	385,452,469	408,759,257	3,763,153	16,371,547		20,134,700	5
								6
								7
	97,611	432,674,962	432,772,573	4,050,922	740,347		4,791,269	8
								9
		17,716,886	17,716,886	206,169	37,680		243,849	10
								11
		63,834,858	63,834,858					12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	199,184,127	3,740,205,778	3,939,389,905	20,761,853	72,581,776		93,343,629	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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	ADDITIONS						
2	UNDERGROUND						
3							
4	OVERHEAD						
5							
6	Cressey-Gallo 115 kV Reliabilt			TSP			
7	Gallo Sub	Cressey Sub	14.40	Wood	18.00	1	1
8	Job Order #31068932			LDSP			
9							
10	Lost Hills Solar Arco-Cornerav						
11	Structure 11/176	Structure 11/178A	0.13	TSP	23.00	1	1
12	Structure 11/177	Structure 0/1	0.01				
13	Job Order #30837089						
14							
15	Wildwood Solar 115kV						
16	Structure 008/070A	Structure 0/1 (POCO)	0.02	TSP	10.00	1	1
17	Structure 7/69	Structure 8/72	0.77				
18	Job Order #30989203						
19							
20	South Kern Solar. Copus-Old						
21	Structure 10/184	Structure 10/185 A	0.07	TSP	15.00	1	1
22	Structure 10/184A	Structure 0/1	0.02				
23	Job Order#30949661						
24							
25	Kettleman Solar.						
26	Structure 74/4	Strucutre 0/1	0.01	TSP	18.00	1	1
27	Job Order# 30985901						
28							
29	Morelos del Sol.						
30	Structure 4/65	Structure 4/67	0.14	TSP	15.00	1	1
31	Structure 4/66	Structure 0/1	0.02				
32	Job Order# 31013983						
33							
34	Vega Solar Project						
35	Los Banos-Canal- Oro Loma	Mercy Springs Switching stn	0.18	TSP	20.00	1	1
36	Job Order#31002021						
37							
38	Solar Star XIII Generation Inn						
39	Structure 5/29	Structure 6/30	0.10	Lattice Steel	8.00	1	1
40	Structure 6/30	Quinto Sw Station Take-Off	0.10				
41	Quinto Sw Station Take-Off	Structure 0/1	0.03				
42	Job Order #30836233,						
43							
44	TOTAL		97.84		305.00	21	21

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	Centennial Corridor Line Reloc						
2	Kern-Westpark no. 1 Str	Structure 2/17	0.32	TSP	10.00	2	2
3	Kern-Westpark no. 2 Str	Structure 2/17	0.32				
4	Kern-Magunden-Witco Str	Structure 2/16	0.31				
5	Kern-Magunden Str 2/14A	Structure 2/16	0.31				
6	Job Order#30969840						
7							
8	Maricopa West Solar						
9	Structure 3/59	Structure 3/61	0.12	TSP	17.00	1	1
10	Structure 3/60	Structure 0/1	0.06				
11	Job Order #31005427,						
12							
13	Chowchilla Solar Generation						
14	Le Grand – Dairyland 115 kV	Structure 0/1	0.03	TSP	18.00	1	1
15	Job Order# 30933872						
16							
17	RECONDUCTOR						
18	UNDERGOUND						
19	OVERHEAD						
20							
21	Contra Costa Moraga Line 1						
22	Contra Costa Substation	Moraga Sub TOSs	26.70	Lattice Steel	5.00	2	2
23	Job Order #30983398 &						
24							
25	Kern OR #2 Panama Ln to			Wood Poles			
26	Panama Junction Pole 5/47	Panama Sub Pole9/116	4.25	LDS	17.00	1	1
27	Job Order #31003772			TSP			
28							
29	McMullin Kearney						
30	McMullin Substation	Kearney Substation	14.10	Steel Towers	19.00	1	1
31	Job Order #30774374						
32							
33	Menlo Area Reconductor						
34	Glenwood Sub	Tower 6/93	2.06	Wood Poles	18.00	1	1
35	Job Order #30654634						
36							
37	Midway-Temblor 115 kV						
38	Temblor Substation CB 312	Structure 14/180	0.09	Wood Poles	16.00	1	1
39	Job Order # 31136533						
40							
41	Solar Star XIII Generation Inn						
42	Structure 0/1	Structure 22/100	28.70	Lattice Steel	8.00	1	1
43	Job Order #30836233,						
44	TOTAL		97.84		305.00	21	21

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2	REMOVALS						
3	UNDERGROUND						
4							
5	OVERHEAD						
6							
7	RIO OSO-Lincoln Hwy 65						
8	RIO OSO str 7/135	Lincoln Substation str 113	4.10	Concrete	18.00	1	1
9	Job Order #30811421			TSP			
10							
11	R2 AMD Tap Removal						
12	Structure 0/5A	Structure 0/11	0.37	Wood Poles	32.00	1	1
13	Job Order # 31101526						
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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27							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		97.84		305.00	21	21

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	LINE COST Poles, Towers and Fixtures (m)	LINE COST Conductors and Devices (n)	LINE COST Asset Retire. Costs (o)	LINE COST Total (p)	Line No.
									1
									2
									3
									4
									5
		Triangular							6
715	AAC	Vertical	115		1,661,794	6,330,119		7,991,913	7
		Single							8
									9
		Vertical							10
1113	AAC	Single	70		71,987	26,632		98,619	11
									12
									13
									14
									15
715.5	AAC	Vertical	115	182,855	362,076	474,942		1,019,873	16
397.5	AAC	Single							17
									18
									19
									20
1113	AAC	Vertical	70		371,540	738,001		1,109,541	21
		Single							22
									23
									24
									25
715	AAC	Triangular	70	35,541	371,701	583,399		990,641	26
		Single							27
									28
									29
715	AAC	Vertical	70		285,308	620,407		905,715	30
		Single							31
									32
									33
									34
715	AAC	Vertical	70		105,711	110,974		216,685	35
		Single							36
									37
									38
795	ACSS	Vertical	230		1,415,344	177,617		1,592,961	39
		Bundle							40
									41
									42
									43
				2,001,455	19,417,680	75,940,880		97,360,015	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	02/24/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
795	ACSS	Vertical	115	64,642	1,915,812			1,980,454	2
795	ACSS	Single	115						3
795	ACSS		115						4
715	ACSS		70						5
									6
									7
									8
715	AAC	Vertical	70		808,296	297,532		1,105,828	9
		Single							10
									11
									12
									13
266.8	ACSR	Vertical	115		446,794	413,704		860,498	14
		Single							15
									16
									17
									18
									19
									20
									21
954	ACSS	Vertical	230		4,888,142	29,021,572		33,909,714	22
		Single							23
									24
		Triangular							25
795	ACSS	Vertical	70		3,187,529	6,671,462		9,858,991	26
		Single							27
									28
									29
1113	ACSS	Vertical	230	1,718,417	709,569	4,579,067		7,007,053	30
		Single							31
									32
									33
715	AAC	Triangular	60		1,239,289	3,420,781		4,660,070	34
		Single							35
									36
									37
715	AAC	Vertical	115		2,773	74,185		76,958	38
		Single							39
									40
									41
795	ACSS	Vertical	230		1,415,344	22,163,494		23,578,838	42
		Bundle							43
				2,001,455	19,417,680	75,940,880		97,360,015	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	02/24/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
1113	AAC	Vertical	115		128,744	26,560		155,304	8
		Single							9
									10
		Triangular							11
4/0	AAC	Vertical	115		29,927	210,432		240,359	12
		Single							13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
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									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				2,001,455	19,417,680	75,940,880		97,360,015	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	02/24/2016	End of 2015/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

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	BELLEVUE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
2	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
3	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
4	BELMONT SUB, Belmont	Distribution	115.00	12.00	7.20
5	BERESFORD SUB, San Mateo	Distribution	60.00	4.00	
6	BERRENDA A SUB,	Distribution	70.00	12.00	2.40
7	BIG BASIN SUB, Santa Cruz	Distribution	60.00	12.00	
8	BIG MEADOWS SUB, Greenville	Distribution	60.00	44.00	2.40
9	BIG RIVER SUB, Mendocino	Transmission	60.00	12.00	2.40
10	BIOLA SUB, Biola	Distribution	70.00	12.00	2.40
11	BLACKWELL SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
12	BLUE LAKE SUB, Blue Lake	Distribution	60.00	12.00	2.40
13	BOGUE SUB, Yuba City	Distribution	115.00	12.00	7.20
14	BOLINAS SUB, Boninas	Distribution	60.00	12.00	7.20
15	BONITA SUB, Madera	Distribution	70.00	12.00	7.20
16	BORDEN SUB, Madera	Transmission	230.00	70.00	13.20
17	BORDEN SUB, Madera	Transmission	230.00	12.00	7.20
18	BOWLES SUB, Bowles	Distribution	70.00	12.00	2.40
19	BRENTWOOD SUB, Brentwood	Distribution	230.00	21.00	7.20
20	BRIDGEVILLE SUB, Bridgeville	Transmission	115.00	60.00	13.20
21	BRIGHTON SUB, Sacramento	Transmission	230.00	115.00	13.20
22	BRITTON SUB, Sunnyvale	Distribution	115.00	12.00	
23	BRUNSWICK SUB, Grass Valley	Distribution	115.00	12.00	7.20
24	BUELLTON SUB, Buellton /93427	Distribution	115.00	12.00	7.20
25	BUENA VISTA SUB, Salinas	Distribution	60.00	12.00	7.20
26	BULLARD SUB, Fresno	Distribution	115.00	12.00	7.20
27	BULLARD SUB, Fresno	Distribution	115.00	21.00	7.20
28	BURLINGAME SUB, Burlingame	Distribution	115.00	21.00	7.20
29	BUTTE SUB, Chico	Transmission	115.00	60.00	12.00
30	BUTTE SUB, Chico	Transmission	115.00	12.00	7.20
31	CABRILLO SUB, LOMPOC	Distribution	115.00	12.00	7.20
32	CADET SUB, Maricopa	Distribution	70.00	12.00	
33	CAL WATER SUB,	Distribution	115.00	12.00	7.20
34	CALAVERAS CEMENT SUB, San Andreas	Distribution	60.00	12.00	7.20
35	CALFLAX SUB, Huron	Distribution	70.00	12.00	2.40
36	CALIFORNIA AVE SUB, Fresno	Distribution	115.00	12.00	7.20
37	CALISTOGA SUB, Calistoga	Distribution	60.00	12.00	7.20
38	CALPELLA SUB, Calpella	Distribution	115.00	12.00	7.20
39	CAMDEN SUB, Riverdale	Distribution	70.00	12.00	2.40
40	CAMP EVERS SUB, Santa Cruz	Distribution	115.00	21.00	7.20

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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	CAMPHORA SUB, Monterey	Distribution	60.00	12.00	7.20
2	CAMPHORA SUB, Monterey	Distribution	60.00	4.00	
3	CANAL SUB, Los Banos	Distribution	70.00	12.00	7.20
4	CANTUA SUB, Cantua Creek	Distribution	115.00	12.00	
5	CAPAY SUB, Orland	Distribution	60.00	12.00	2.40
6	CARBONA SUB, Tracy	Distribution	60.00	12.00	7.20
7	CARNATION SUB, Bakersfield	Distribution	70.00	21.00	7.20
8	CARNERAS SUB, Blackwells Corner	Distribution	70.00	12.00	7.20
9	CAROLANDS SUB, Hillsborough	Distribution	60.00	4.00	
10	CARQUINEZ SUB, Vallejo	Distribution	115.00	12.00	2.40
11	CARUTHERS SUB, Fresno	Distribution	70.00	12.00	2.40
12	CASCADE SUB, Pine Grove	Transmission	115.00	60.00	13.20
13	CASSIDY SUB, Madera	Distribution	70.00	12.00	2.40
14	CASTRO VALLEY SUB, Castro Valley	Distribution	230.00	12.00	
15	CASTROVILLE SUB, Castroville	Distribution	115.00	21.00	7.20
16	CAWELO B SUB, Famosa	Distribution	70.00	4.00	
17	CAYETANO SUB, Danville	Distribution	230.00	21.00	7.20
18	CAYUCOS SUB, Cayucos	Distribution	70.00	12.00	7.20
19	CHANNEL SUB, Stockton	Distribution	60.00	12.00	
20	CHARCA SUB, Wasco	Distribution	115.00	12.00	7.20
21	CHENEY SUB, Mendota	Distribution	115.00	12.00	7.20
22	CHEROKEE SUB, Stockton	Distribution	60.00	12.00	7.20
23	CHICO A SUB, Chico	Distribution	60.00	12.00	7.20
24	CHICO B SUB, Chico	Distribution	115.00	12.00	7.20
25	CHOLAME SUB, Cholame/93431	Distribution	70.00	12.00	2.40
26	CHOLAME SUB, Cholame/93431	Distribution	70.00	21.00	2.40
27	CHOWCHILLA SUB, Chowchilla	Distribution	115.00	12.00	7.20
28	CHRISTIE SUB, Hercules	Transmission	115.00	60.00	13.20
29	CLARK ROAD SUB, Paradise	Distribution	60.00	12.00	2.40
30	CLARKSVILLE SUB, Clarksville	Distribution	115.00	21.00	7.20
31	CLAY SUB, Ione	Distribution	60.00	12.00	2.40
32	CLAYTON SUB, Concord	Distribution	115.00	21.00	7.20
33	CLAYTON SUB, Concord	Distribution	115.00	12.00	7.20
34	CLEAR LAKE SUB, Finley	Distribution	60.00	12.00	2.40
35	CLOVERDALE SUB, Cloverdale	Distribution	115.00	12.00	7.20
36	CLOVIS SUB, Clovis	Distribution	115.00	12.00	7.20
37	CLOVIS SUB, Clovis	Distribution	115.00	21.00	7.20
38	COALINGA #1 SUB, Coalinga	Distribution	70.00	12.00	7.20
39	COALINGA #2 SUB, Coalinga	Distribution	70.00	12.00	2.40
40	COARSEGOLD SUB, Coursegold	Distribution	115.00	21.00	7.20

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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	COBURN SUB, King City	Transmission	230.00	60.00	13.20
2	COLUMBUS SUB, Bakersfield	Distribution	115.00	12.00	7.20
3	COLUSA JUNCT SUB, Colusa	Distribution	60.00	12.00	7.20
4	COLUSA SUB, Colusa	Distribution	60.00	12.00	
5	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	60.00	13.20
6	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	115.00	13.20
7	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	21.00	7.20
8	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	21.00	6.60
9	COOLEY LANDING SUB, Palo Alto	Transmission	115.00	60.00	13.80
10	COPPERMINE SUB, Clovis	Distribution	70.00	12.00	2.40
11	COPUS SUB, Bakersfield	Distribution	70.00	12.00	
12	CORCORAN SUB, Corcoran	Transmission	115.00	70.00	13.20
13	CORCORAN SUB, Corcoran	Transmission	115.00	12.00	7.20
14	CORDELIA SUB, Cordelia	Distribution	115.00	12.00	7.20
15	CORDELIA SUB, Cordelia	Distribution	60.00	12.00	2.40
16	CORNING SUB, Corning	Distribution	60.00	12.00	2.40
17	CORONA SUB,	Distribution	115.00	12.00	7.20
18	CORRAL SUB, Bellota	Distribution	60.00	12.00	7.20
19	CORTINA SUB, Williams	Transmission	115.00	60.00	13.20
20	CORTINA SUB, Williams	Transmission	230.00	115.00	13.20
21	CORTINA SUB, Williams	Transmission	115.00	12.00	7.20
22	COTATI SUB, Cotati	Distribution	60.00	12.00	
23	COTTLE SUB, Oakdale	Distribution	230.00	17.00	
24	COTTONWOOD SUB, Cottonwood	Transmission	230.00	60.00	13.20
25	COTTONWOOD SUB, Cottonwood	Transmission	230.00	115.00	13.20
26	COTTONWOOD SUB, Cottonwood	Transmission	115.00	12.00	7.20
27	COUNTRY CLUB SUB, Stockton	Distribution	60.00	12.00	
28	COUNTRY CLUB SUB, Stockton	Distribution	60.00	4.00	
29	CRESSEY SUB, Merced	Distribution	115.00	21.00	
30	CURTIS SUB, Sonora	Distribution	115.00	18.00	
31	CUYAMA SUB, Cuyama	Distribution	70.00	12.00	
32	CUYAMA SUB, Cuyama	Distribution	70.00	21.00	7.20
33	CYMRIC SUB, McKitrick	Distribution	115.00	12.00	7.20
34	DAIRYLAND SUB, Chowchilla	Distribution	115.00	12.00	7.20
35	DALY CITY SUB, Daly City	Distribution	115.00	12.00	7.20
36	DAVIS SUB, Davis	Distribution	115.00	12.00	7.20
37	DEEPWATER SUB, W. Sacramento	Distribution	115.00	12.00	7.20
38	DEL MAR SUB, Rocklin	Distribution	60.00	21.00	7.20
39	DEL MAR SUB, Rocklin	Distribution	60.00	12.00	7.20
40	DEL MONTE SUB, Monterey	Transmission	115.00	60.00	13.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DEL MONTE SUB, Monterey	Transmission	115.00	21.00	7.20
2	DERRICK SUB, Kettleman	Distribution	70.00	12.00	2.40
3	DESCHUTES SUB, Palo Cedro	Distribution	60.00	12.00	7.20
4	DIAMOND SPRINGS SUB, Placerville	Distribution	115.00	12.00	7.20
5	DINUBA SUB, Dinuba	Distribution	70.00	12.00	2.40
6	DIVIDE SUB, Orcutt	Transmission	115.00	70.00	13.20
7	DIVIDE SUB, Orcutt	Transmission	70.00	12.00	2.40
8	DIXON LANDING SUB,	Distribution	115.00	21.00	7.20
9	DIXON SUB, Dixon	Distribution	60.00	12.00	
10	DOLAN ROAD SUB, Moss Landing	Distribution	115.00	12.00	
11	DOS PALOS SUB, Dos Palos	Distribution	70.00	12.00	7.20
12	DUMBARTON SUB, Fremont	Distribution	115.00	12.00	
13	DUNBAR SUB, Glen Ellen	Distribution	60.00	12.00	
14	EAGLE ROCK SUB, Geysers	Transmission	115.00	60.00	
15	EAST GRAND SUB, So San Fran.	Distribution	115.00	12.00	7.20
16	EAST MARYSVILLE SUB, Marysville,	Distribution	115.00	12.00	7.20
17	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	60.00	
18	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	12.00	
19	EAST STOCKTON SUB, Stockton	Distribution	60.00	12.00	7.20
20	EAST STOCKTON SUB, Stockton	Distribution	60.00	4.00	
21	EASTSHORE SUB, Hayward	Transmission	230.00	115.00	
22	EDENVALE SUB, San Jose	Distribution	115.00	21.00	7.20
23	EDENVALE SUB, San Jose	Distribution	115.00	12.00	7.20
24	EDES SUB, Oakland	Distribution	115.00	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	2.40
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	GARBERVILLE SUB, Garberville	Distribution	60.00	12.00	7.20
28	GATES SUB, Huron	Transmission	115.00	70.00	13.20
29	GATES SUB, Huron	Transmission	230.00	115.00	13.20
30	GATES SUB, Huron	Transmission	500.00	230.00	13.20
31	GATES SUB, Huron	Transmission	230.00	12.00	7.20
32	GATES SUB, Huron	Transmission	115.00	12.00	
33	GEYSERVILLE SUB, Geyserville	Distribution	60.00	12.00	2.40
34	GIFFEN SUB, San Joaquin	Distribution	70.00	12.00	2.40
35	GIRVAN SUB, Redding	Distribution	60.00	12.00	7.20
36	GLENN SUB, Orland	Transmission	230.00	60.00	13.20
37	GLENN SUB, Orland	Transmission	60.00	12.00	
38	GLENWOOD SUB, Menlo Park	Distribution	60.00	12.00	7.20
39	GLENWOOD SUB, Menlo Park	Distribution	60.00	4.00	
40	GOLD HILL SUB, Folsom	Transmission	115.00	60.00	13.20

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1	GOLD HILL SUB, Folsom	Transmission	230.00	115.00	13.20
2	GOLDTREE SUB, SLO	Distribution	115.00	12.00	7.20
3	GONZALES SUB, Gonzales	Distribution	60.00	12.00	
4	GOOSE LAKE SUB, Wasco	Distribution	115.00	12.00	7.20
5	GRAND ISLAND SUB, Ryde	Distribution	115.00	21.00	7.20
6	GRANT SUB, San Lorenzo	Distribution	115.00	12.00	7.20
7	GRASS VALLEY SUB, Grass Valley	Distribution	60.00	12.00	
8	GREEN VALLEY SUB, Watsonville	Transmission	115.00	60.00	
9	GREEN VALLEY SUB, Watsonville	Transmission	115.00	21.00	7.20
10	GREENBRAE SUB, Larkspur	Distribution	60.00	12.00	7.20
11	GUALALA SUB, Gualala	Distribution	60.00	12.00	2.40
12	GUERNSEY SUB, Hanford	Distribution	70.00	12.00	2.40
13	GUSTINE SUB, Gustine	Distribution	60.00	12.00	7.20
14	HALF MOON BAY SUB, Half Moon Bay	Distribution	60.00	12.00	2.40
15	HAMMER SUB, Stockton	Distribution	60.00	12.00	7.20
16	HAMMONDS SUB, Fresno	Distribution	115.00	12.00	
17	HARDING SUB, Stockton	Distribution	60.00	4.00	
18	HARDWICK SUB, Layton	Distribution	70.00	12.00	7.20
19	HARRIS SUB, Eureka	Distribution	60.00	12.00	7.20
20	HARTER SUB, Yuba City	Distribution	60.00	12.00	7.20
21	HARTLEY SUB, Lakeport	Distribution	60.00	12.00	7.20
22	HATTON SUB, Carmel Valley	Distribution	60.00	12.00	2.40
23	HELM SUB, San Joaquin	Transmission	230.00	70.00	13.20
24	HENRIETTA SUB, Lamoore	Transmission	230.00	70.00	13.20
25	HENRIETTA SUB, Lamoore	Transmission	230.00	115.00	2.40
26	HENRIETTA SUB, Lamoore	Transmission	70.00	12.00	2.40
27	HERDLYN SUB, Tracy	Transmission	70.00	60.00	2.40
28	HERDLYN SUB, Tracy	Transmission	60.00	12.00	2.40
29	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20
30	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20
31	HICKS SUB, San Jose	Distribution	230.00	21.00	7.20
32	HICKS SUB, San Jose	Distribution	230.00	12.00	7.20
33	HIGGINS SUB, Higgins Corner	Distribution	115.00	12.00	7.20
34	HIGHLANDS SUB, Clear Lake	Distribution	115.00	12.00	7.20
35	HIGHWAY SUB, Petaluma	Distribution	115.00	12.00	7.20
36	HOLLISTER SUB, Hollister	Distribution	115.00	21.00	7.20
37	HOLLISTER SUB, Hollister	Distribution	60.00	21.00	
38	HONCUT SUB, Honcut	Distribution	115.00	12.00	7.20
39	HOPLAND SUB, Hopland	Transmission	115.00	60.00	13.20
40	HOPLAND SUB, Hopland	Transmission	60.00	12.00	2.40

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HORSESHOE SUB, Granite Bay	Distribution	115.00	12.00	7.20
2	HOWLAND ROAD SUB, Manteca	Distribution	115.00	12.00	7.20
3	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	13.80	
4	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	13.80	
5	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	12.00	7.20
6	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	2.00	
7	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	2.00	
8	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
9	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
10	HURON SUB, Huron	Distribution	70.00	12.00	2.40
11	IGNACIO SUB, Ignacio	Transmission	115.00	60.00	13.20
12	IGNACIO SUB, Ignacio	Transmission	230.00	115.00	13.20
13	IGNACIO SUB, Ignacio	Transmission	115.00	12.00	
14	IMHOFF SUB, Martinez	Distribution	115.00	12.00	7.20
15	IONE SUB, Ione	Distribution	60.00	12.00	7.20
16	JACINTO SUB, Willows	Distribution	60.00	12.00	7.20
17	JACOBS CORNER SUB, Lemoore	Distribution	70.00	12.00	2.40
18	JAMESON SUB, CORDELIA	Distribution	115.00	12.00	7.20
19	JANES CREEK SUB, Arcata	Distribution	60.00	12.00	7.20
20	JARVIS SUB, Union City	Distribution	115.00	12.00	7.20
21	JEFFERSON SUB, Redwood City	Transmission	230.00	60.00	13.20
22	JESSUP SUB, Anderson	Distribution	115.00	12.00	
23	JOLON SUB, King City	Distribution	60.00	12.00	
24	KASSON SUB, Tracy	Transmission	115.00	60.00	13.20
25	KELSO SUB, Tracy	Distribution	230.00	12.00	
26	KERMAN SUB, Kerman	Distribution	70.00	12.00	7.20
27	KERN OIL SUB, Bakersfield	Distribution	115.00	12.00	7.20
28	KERN PP DIST SUB, Bakersfield	Distribution	115.00	21.00	7.20
29	KERN PP SUB, Bakersfield	Transmission	115.00	70.00	13.20
30	KERN PP SUB, Bakersfield	Transmission	230.00	115.00	13.20
31	KESWICK SUB, Keswick	Distribution	60.00	12.00	2.40
32	KETTLEMAN HILLS SUB, Kettleman	Distribution	70.00	12.00	2.40
33	KING CITY SUB, King City	Distribution	60.00	12.00	
34	KINGSBURG SUB, Kingsburg	Transmission	115.00	70.00	13.80
35	KINGSBURG SUB, Kingsburg	Transmission	115.00	12.00	7.20
36	KIRKER SUB, Pittsburg	Distribution	115.00	21.00	7.20
37	KONOCTI SUB, Clear Lake	Distribution	60.00	12.00	2.40
38	LAKEVIEW SUB, Bakersfield	Distribution	70.00	12.00	2.40
39	LAKEVILLE SUB, Petaluma	Transmission	230.00	60.00	13.20
40	LAKEVILLE SUB, Petaluma	Transmission	230.00	115.00	13.20

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1	LAKEVILLE SUB, Petaluma	Transmission	115.00	12.00	7.20
2	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	21.00	7.20
3	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	12.00	7.20
4	LAMMERS SUB, TRACY	Distribution	115.00	12.00	7.20
5	LAMONT SUB, Bakersfield	Distribution	115.00	12.00	
6	LAS GALLINAS A SUB, Las Gallinas	Distribution	115.00	12.00	7.20
7	LAS PALMAS SUB, Fresno	Distribution	115.00	12.00	7.20
8	LAS POSITAS SUB, Livermore	Transmission	230.00	60.00	13.20
9	LAS POSITAS SUB, Livermore	Transmission	230.00	21.00	7.20
10	LAS PULGAS SUB, Redwood City	Distribution	60.00	4.00	2.40
11	LAWRENCE SUB, Sunnyvale	Distribution	115.00	12.00	7.20
12	LE GRAND SUB, Le Grand	Distribution	115.00	12.00	7.20
13	LEMOORE SUB, Armonia	Distribution	70.00	12.00	2.40
14	LERDO SUB, Bakersfield	Distribution	115.00	12.00	7.20
15	LINCOLN SUB, Lincoln	Distribution	115.00	12.00	7.20
16	LINDEN SUB, Linden	Distribution	60.00	12.00	2.40
17	LIVE OAK SUB, Live Oak	Distribution	60.00	12.00	
18	LIVERMORE SUB, Livermore	Distribution	60.00	12.00	2.40
19	LIVINGSTON SUB, Livingston	Distribution	115.00	12.00	7.20
20	LIVINGSTON SUB, Livingston	Distribution	70.00	12.00	
21	LLAGAS SUB, Gilroy	Distribution	115.00	21.00	12.00
22	LOCKEFORD SUB, Lockeford	Transmission	230.00	60.00	13.20
23	LOCKEFORD SUB, Lockeford	Transmission	115.00	21.00	7.20
24	LOCKHEED #2 SUB, Sunnyvale	Distribution	115.00	12.00	
25	LODI SUB, Lodi	Distribution	60.00	12.00	2.40
26	LODI SUB, Lodi	Distribution	60.00	4.00	
27	LOGAN CREEK SUB, Willows	Distribution	230.00	21.00	
28	LONETREE SUB, Antioch	Distribution	230.00	21.00	7.20
29	LOS ALTOS SUB, Los Altos	Distribution	60.00	12.00	
30	LOS BANOS SUB, Los Banos	Transmission	230.00	70.00	13.20
31	LOS BANOS SUB, Los Banos	Transmission	500.00	230.00	13.80
32	LOS COCHES SUB, Greenfield	Distribution	60.00	12.00	
33	LOS ESTEROS SUB,	Transmission	230.00	115.00	12.00
34	LOS GATOS SUB, Los Gatos	Distribution	60.00	12.00	7.20
35	LOS MOLINOS SUB, Los Molinos	Distribution	60.00	12.00	7.20
36	LOS OSITOS SUB, Monterey	Distribution	60.00	21.00	7.20
37	LOYOLA SUB, Loyola	Distribution	60.00	12.00	7.20
38	LOYOLA SUB, Loyola	Distribution	60.00	4.00	2.40
39	LUCERNE SUB, Lucerne	Distribution	115.00	12.00	7.20
40	MABURY SUB, San Jose	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	02/24/2016	End of 2015/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	MABURY SUB, San Jose	Distribution	115.00	12.00	7.20
2	MADERA SUB, Madera	Distribution	70.00	12.00	
3	MADISON SUB, Madison	Distribution	60.00	12.00	7.20
4	MADISON SUB, Madison	Distribution	115.00	12.00	
5	MAGUNDEN SUB, Bakersfield	Distribution	115.00	12.00	7.20
6	MAGUNDEN SUB, Bakersfield	Distribution	115.00	21.00	7.20
7	MALAGA SUB, Fresno	Distribution	115.00	12.00	7.20
8	MANCHESTER SUB, Fresno	Distribution	115.00	12.00	7.20
9	MANTECA SUB, Manteca	Transmission	115.00	60.00	12.80
10	MANTECA SUB, Manteca	Transmission	115.00	17.00	
11	MARICOPA SUB, Maricopa	Distribution	70.00	12.00	2.40
12	MARIPOSA SUB, Mariposa	Distribution	70.00	21.00	
13	MARTELL SUB, Martell	Distribution	60.00	12.00	2.40
14	MARYSVILLE SUB, Marysville	Distribution	60.00	12.00	
15	MAXWELL SUB, Maxwell	Distribution	60.00	12.00	
16	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
17	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
18	MCCALL SUB, Selma	Transmission	115.00	12.00	7.20
19	MCDONALD-MCDONALDISLAND SUB, Stockton	Distribution	60.00	4.00	2.40
20	MCFARLAND SUB, McFarland	Distribution	70.00	12.00	7.20
21	MCKEE SUB, San Jose	Distribution	115.00	12.00	7.20
22	MCKITTRICK SUB, MCKITTRICK	Distribution	70.00	12.00	
23	MCMULLIN SUB, Fresno	Distribution	230.00	12.00	7.20
24	MEADOW LANE SUB, Concord	Distribution	115.00	21.00	7.20
25	MENDOCINO SUB, Redwood Valley	Transmission	115.00	60.00	13.20
26	MENDOCINO SUB, Redwood Valley	Transmission	60.00	12.00	2.40
27	MENDOTA SUB, Mendota	Transmission	115.00	70.00	12.00
28	MENDOTA SUB, Mendota	Transmission	115.00	12.00	7.20
29	MENLO SUB, Menlo Park	Distribution	60.00	12.00	7.20
30	MENLO SUB, Menlo Park	Distribution	60.00	4.00	
31	MERCED SUB, Merced	Transmission	115.00	70.00	6.60
32	MERCED SUB, Merced	Transmission	115.00	12.00	7.20
33	MERCED SUB, Merced	Transmission	115.00	21.00	7.20
34	MERIDIAN SUB, Meridian	Distribution	60.00	12.00	
35	MESA SUB, Nipomo	Transmission	230.00	115.00	13.20
36	MESA SUB, Nipomo	Transmission	230.00	12.00	
37	METCALF SUB, San Jose	Transmission	500.00	230.00	13.80
38	METCALF SUB, San Jose	Transmission	230.00	115.00	13.20
39	METTLER SUB, Stockton	Distribution	60.00	12.00	
40	MIDDLETOWN SUB, Middletown	Distribution	60.00	12.00	7.20

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MIDWAY SUB, Buttonwillow	Transmission	230.00	115.00	13.20
2	MIDWAY SUB, Buttonwillow	Transmission	500.00	230.00	13.80
3	MIDWAY SUB, Buttonwillow	Transmission	115.00	12.00	7.20
4	MILLBRAE SUB, Millbrae	Transmission	115.00	60.00	13.80
5	MILLBRAE SUB, Millbrae	Transmission	115.00	12.00	
6	MILLBRAE SUB, Millbrae	Transmission	60.00	4.00	
7	MILPITAS SUB, Milpitas	Distribution	115.00	21.00	7.20
8	MILPITAS SUB, Milpitas	Distribution	115.00	12.00	7.20
9	MIRABEL SUB, Forestville	Distribution	60.00	12.00	
10	MI-WUK SUB, Sugarpine	Distribution	115.00	17.00	
11	MOLINO SUB, Sebastopol	Distribution	60.00	12.00	7.20
12	MONROE SUB, Santa Rosa	Distribution	115.00	21.00	7.20
13	MONROE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
14	MONTA VISTA SUB, Cupertino	Transmission	115.00	60.00	13.20
15	MONTA VISTA SUB, Cupertino	Transmission	230.00	60.00	
16	MONTA VISTA SUB, Cupertino	Transmission	230.00	115.00	13.20
17	MONTAGUE SUB, San Jose	Distribution	115.00	21.00	7.20
18	MONTE RIO SUB, Monte Rio	Distribution	60.00	12.00	7.20
19	MONTEREY SUB, Monterey	Distribution	60.00	4.00	
20	MORAGA SUB, Orinda	Transmission	230.00	115.00	13.20
21	MORAGA SUB, Orinda	Transmission	115.00	12.00	
22	MORGAN HILL SUB, Morgan Hill	Distribution	115.00	21.00	7.20
23	MORMON SUB, Stockton	Distribution	60.00	12.00	7.20
24	MORRO BAY PP SWYD, Morro Bay	Transmission	230.00	115.00	13.20
25	MORRO BAY PP SWYD, Morro Bay	Transmission	115.00	12.00	7.20
26	MOSHER SUB, Stockton	Distribution	60.00	21.00	7.20
27	MOSS LANDING PP SUB, Moss Landing	Transmission	230.00	115.00	13.20
28	MOSS LANDING PP SUB, Moss Landing	Transmission	500.00	230.00	13.80
29	MOUNTAIN VIEW SUB, Mt. View	Distribution	115.00	12.00	7.20
30	MT. EDEN SUB, Hayward	Distribution	115.00	12.00	7.20
31	MT. QUARRIES SUB, Cool	Distribution	60.00	12.00	7.20
32	NAPA SUB, Napa	Distribution	60.00	12.00	
33	NEW KEARNEY SUB, FRESNO	Transmission	230.00	70.00	13.20
34	NEWARK DIST SUB, Fremont	Distribution	230.00	21.00	7.20
35	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
36	NEWARK SUB, Fremont	Transmission	115.00	60.00	13.20
37	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
38	NEWARK SUB, Fremont	Transmission	115.00	12.00	7.20
39	NEWBURG SUB, Fortuna	Distribution	60.00	12.00	2.40
40	NEWHALL SUB, Firebaugh	Distribution	115.00	12.00	7.20

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1	NEWMAN SUB, Newman	Distribution	60.00	12.00	7.20
2	NORCO SUB, Bakersfield	Distribution	115.00	12.00	7.20
3	NORD SUB, Chico	Distribution	115.00	12.00	7.20
4	NORTECH SUB, San Jose	Distribution	115.00	21.00	7.20
5	NORTH DUBLIN SUB, Pleasanton	Distribution	230.00	21.00	12.00
6	NORTH TOWER SUB, Vallejo	Distribution	115.00	12.00	7.20
7	NORTH TOWER SUB, Vallejo	Distribution	115.00	25.00	7.20
8	NOTRE DAME SUB, Chico	Distribution	115.00	12.00	7.20
9	NOVATO SUB, Novato	Distribution	60.00	12.00	7.20
10	OAKHURST SUB, Oakhurst	Distribution	115.00	12.00	2.40
11	OAKLAND C (OAKLAND PP) SUB, Oakland	Distribution	115.00	12.00	7.20
12	OAKLAND D SUB, Oakland	Distribution	115.00	12.00	7.20
13	OAKLAND J SUB, Oakland	Distribution	115.00	12.00	7.20
14	OAKLAND K (CLAREMONT) SUB, Oakland	Distribution	115.00	12.00	6.60
15	OAKLAND L SUB, Oakland	Distribution	115.00	12.00	7.20
16	OAKLAND X SUB, Oakland	Distribution	115.00	12.00	7.20
17	OCEANO SUB, Oceano	Distribution	115.00	12.00	7.20
18	OILFIELDS SUB, San Ardo	Distribution	60.00	12.00	
19	OLD KEARNEY SUB, Fresno	Distribution	70.00	12.00	13.20
20	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	2.40
21	OLETA SUB, Plymouth	Distribution	60.00	12.00	2.40
22	OLIVEHURST SUB, Olivehurst	Distribution	115.00	12.00	7.20
23	OREGON TRAIL SUB, Redding	Distribution	115.00	12.00	7.20
24	OREGON TRAIL SUB, Redding	Distribution	60.00	12.00	2.40
25	ORLAND B SUB, Orland	Distribution	60.00	12.00	2.40
26	ORO FINO SUB, Magalia	Distribution	60.00	12.00	2.40
27	ORO LOMA SUB, Dos Palos	Transmission	115.00	70.00	13.20
28	ORO LOMA SUB, Dos Palos	Transmission	70.00	12.00	2.40
29	ORO LOMA SUB, Dos Palos	Transmission	115.00	12.00	
30	OROSI SUB, Orosi	Distribution	70.00	12.00	7.20
31	OROVILLE SUB, Oroville	Distribution	60.00	12.00	7.20
32	OROVILLE SUB, Oroville	Distribution	60.00	4.00	2.40
33	ORTIGA SUB, Los Banos	Distribution	70.00	12.00	2.40
34	PACIFICA SUB, Pacifica	Distribution	60.00	12.00	
35	PALERMO SUB, Palermo	Transmission	230.00	60.00	
36	PALERMO SUB, Palermo	Transmission	230.00	115.00	13.20
37	PALMER SUB, Sisquat	Distribution	115.00	12.00	7.20
38	PANAMA SUB, Bakersfield	Distribution	70.00	21.00	7.20
39	PANOCHE SUB, Mendota	Transmission	230.00	115.00	13.20
40	PANORAMA SUB, Anderson	Distribution	115.00	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	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	12.00	
33	PUEBLO SUB, Napa	Distribution	115.00	21.00	
34	PURISIMA SUB, Lompoc	Distribution	115.00	12.00	7.20
35	PUTAH CREEK SUB, Winters	Distribution	115.00	12.00	
36	RACE TRACK SUB, Jamestown	Distribution	115.00	17.00	
37	RADUM SUB, Pleasanton	Distribution	60.00	12.00	
38	RAINBOW SUB, Sanger	Distribution	115.00	12.00	7.20
39	RALSTON SUB, Belmont	Distribution	60.00	12.00	
40	RANCHERS COTTON SUB, Fresno	Distribution	115.00	12.00	7.20

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1	RAVENSWOOD SUB, Menlo Park	Transmission	230.00	115.00	13.20
2	RAWSON SUB, Red Bluff	Distribution	60.00	12.00	2.40
3	RED BLUFF SUB, Red Bluff	Distribution	60.00	12.00	2.40
4	REDBUD SUB, Clearlake Oaks	Distribution	115.00	12.00	7.20
5	REDWOOD CITY SUB, Redwood City	Distribution	60.00	12.00	7.20
6	REDWOOD CITY SUB, Redwood City	Distribution	60.00	4.00	
7	REEDLEY SUB, Reedley	Transmission	115.00	70.00	13.20
8	REEDLEY SUB, Reedley	Transmission	115.00	12.00	7.20
9	REEDLEY SUB, Reedley	Transmission	70.00	12.00	2.40
10	RENFRO SUB, BAKERSFIELD	Distribution	115.00	12.00	7.20
11	RESEARCH SUB, San Ramon	Distribution	230.00	21.00	7.20
12	RESERVATION ROAD SUB, Salinas	Distribution	60.00	12.00	2.40
13	RESERVE OIL SUB, Hanford	Distribution	70.00	12.00	2.40
14	RESERVE OIL SUB, Hanford	Distribution	70.00	4.00	
15	RICE SUB, Princeton	Distribution	60.00	12.00	4.16
16	RICHMOND R SUB, Richmond	Distribution	115.00	12.00	7.20
17	RINCON SUB, Santa Rosa	Distribution	115.00	12.00	
18	RIO BRAVO SUB, Shafter	Distribution	115.00	12.00	7.20
19	RIO DELL SUB, Rio Dell	Distribution	60.00	12.00	
20	RIO OSO SUB, Rio Oso	Transmission	230.00	115.00	13.20
21	RIPON SUB, Ripon	Distribution	115.00	17.00	
22	RISING RIVER SUB, Cassell,	Distribution	60.00	12.00	2.40
23	RIVER OAKS SUB, San Jose	Distribution	115.00	21.00	7.20
24	RIVERBANK SUB, Escalon	Distribution	115.00	12.00	
25	ROB ROY SUB, Watsonville	Distribution	115.00	21.00	7.20
26	ROCKLIN SUB, Rocklin	Distribution	60.00	12.00	7.20
27	ROSEDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
28	ROSSMOOR SUB, Walnut Creek	Distribution	230.00	12.00	
29	ROUGH & READY ISLAND SUB, Stockton	Distribution	60.00	12.00	7.20
30	ROUND MOUNTAIN SUB, Rd Mtn	Transmission	500.00	230.00	13.80
31	SALADO SUB, Patterson	Transmission	115.00	60.00	12.00
32	SALINAS SUB, Salinas	Transmission	115.00	60.00	13.20
33	SALINAS SUB, Salinas	Transmission	115.00	12.00	7.20
34	SALMON CREEK SUB, Bodega Bay	Distribution	60.00	12.00	2.40
35	SAN ARDO SUB, San Ardo	Distribution	60.00	12.00	
36	SAN BENITO SUB, San Benito	Distribution	115.00	21.00	7.20
37	SAN BERNARD SUB, Lamont	Distribution	70.00	12.00	2.40
38	SAN CARLOS SUB, San Carlos	Distribution	60.00	12.00	7.20
39	SAN CARLOS SUB, San Carlos	Distribution	60.00	4.00	2.40
40	SAN FRAN A (POTRERO PP) SUB, San Francisco	Distribution	115.00	12.00	7.20

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1	SAN FRAN A (POTRERO PP) SUB, San Francisco	Distribution	115.00	12.00	7.20
2	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	60.00	
3	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	230.00	115.00	
4	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	12.00	
5	SAN FRAN P-HUNTERS POINT SUB, San Francisco	Distribution	115.00	12.00	
6	SAN FRAN X (MISSION) SUB, San Francisco	Distribution	115.00	12.00	7.20
7	SAN FRAN Y (LARKIN) SUB, San Francisco	Distribution	115.00	12.00	7.20
8	SAN FRAN Z (Embarcadero), San Francisco	Distribution	230.00	34.50	7.20
9	SAN JOAQUIN SUB, San Joaquin	Distribution	70.00	12.00	7.20
10	SAN JOSE A SUB, San Jose	Distribution	115.00	4.00	7.20
11	SAN JOSE A SUB, San Jose	Distribution	115.00	12.00	
12	SAN JOSE B SUB, San Jose	Distribution	115.00	12.00	7.20
13	SAN LEANDRO U SUB, San Leandro	Distribution	115.00	12.00	
14	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	70.00	13.20
15	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	12.00	7.20
16	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
17	SAN MATEO SUB, San Mateo	Transmission	115.00	60.00	
18	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
19	SAN MATEO SUB, San Mateo	Transmission	115.00	21.00	
20	SAN MATEO SUB, San Mateo	Transmission	60.00	4.00	
21	SAN MIGUEL SUB, San Miguel	Distribution	70.00	12.00	7.20
22	SAN PABLO SUB, Richmond	Distribution	115.00	12.00	7.20
23	SAN RAFAEL SUB, San Rafael	Distribution	115.00	12.00	4.16
24	SAN RAMON SUB, San Ramon	Transmission	230.00	60.00	13.20
25	SAN RAMON SUB, San Ramon	Transmission	230.00	21.00	12.00
26	SANGER SUB, Fresno	Transmission	115.00	70.00	6.60
27	SANGER SUB, Fresno	Transmission	115.00	12.00	7.20
28	SANTA MARIA SUB, Santa Maria	Distribution	115.00	12.00	7.20
29	SANTA NELLA SUB, Santa Nella	Distribution	70.00	12.00	2.40
30	SANTA RITA SUB, Dos Palos	Distribution	70.00	12.00	2.40
31	SANTA ROSA A SUB, Santa Rosa	Distribution	115.00	12.00	7.20
32	SANTA YNEZ SUB, Santa Maria	Distribution	115.00	12.00	7.20
33	SARATOGA SUB, Saratoga	Distribution	230.00	12.00	7.20
34	SAUSALITO SUB, Sausalito	Distribution	60.00	12.00	2.40
35	SAUSALITO SUB, Sausalito	Distribution	60.00	4.00	
36	SCHINDLER SUB, Five Points	Transmission	115.00	70.00	13.20
37	SCHINDLER SUB, Five Points	Transmission	115.00	12.00	7.20
38	SEMITROPIC SUB, Wasco	Transmission	115.00	70.00	13.80
39	SEMITROPIC SUB, Wasco	Transmission	115.00	12.00	7.20
40	SERRAMONTE SUB, Daly City	Distribution	115.00	12.00	

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	SHAFTER SUB, Shafter	Distribution	115.00	12.00	7.20
2	SHARON SUB, Chowchilla	Distribution	115.00	12.00	
3	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	21.00	7.20
4	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	12.00	7.20
5	SHREDDER SUB, Redwood City	Distribution	115.00	4.00	6.60
6	SILVERADO SUB, St. Helena	Distribution	115.00	21.00	
7	SISQUOC SUB, Orcutt	Distribution	115.00	12.00	7.20
8	SMYRNA SUB, Wasco	Distribution	115.00	12.00	7.20
9	SNEATH LANE SUB, San Bruno	Distribution	60.00	12.00	2.40
10	SOBRANTE SUB, Orinda	Transmission	230.00	115.00	
11	SOBRANTE SUB, Orinda	Transmission	115.00	12.00	7.20
12	SOLEDAD SUB, Soledad	Transmission	115.00	60.00	
13	SOLEDAD SUB, Soledad	Transmission	60.00	12.00	
14	SONOMA A SUB, Sonoma	Distribution	115.00	12.00	
15	SOUTH BAY #1 & #2 SUB, Tracy	Distribution	60.00	4.00	
16	SPANISH CREEK SUB,	Distribution	60.00	44.00	
17	SPENCE SUB, Salinas	Distribution	60.00	12.00	
18	SRI SUB, Menlo Park	Distribution	60.00	12.00	
19	STAFFORD SUB, Novato	Distribution	60.00	12.00	
20	STAGG SUB, Stockton	Transmission	230.00	60.00	13.20
21	STAGG SUB, Stockton	Transmission	230.00	21.00	7.20
22	STAGG SUB, Stockton	Transmission	60.00	12.00	2.40
23	STALLION SUB, Bakersfield	Distribution	70.00	4.00	7.20
24	STELLING SUB, Cupertino	Distribution	115.00	12.00	7.20
25	STILLWATER STA SUB, Project City	Distribution	60.00	12.00	2.40
26	STOCKDALE SUB, Bakersfield	Distribution	230.00	21.00	7.20
27	STOCKDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
28	STOCKTON A SUB, Stockton	Transmission	115.00	12.00	
29	STOCKTON A SUB, Stockton	Transmission	60.00	4.00	
30	STONE CORRAL SUB, Woodlake	Distribution	70.00	12.00	2.40
31	STONE SUB, San Jose	Distribution	115.00	12.00	7.20
32	STOREY SUB, Madera	Distribution	230.00	12.00	7.20
33	STROUD SUB, Helm	Distribution	70.00	12.00	2.40
34	SUISUN SUB, Fairfield	Distribution	115.00	12.00	7.20
35	SUNOL SUB, Sunol	Distribution	60.00	12.00	7.20
36	SWIFT SUB, San Jose	Distribution	115.00	21.00	7.20
37	SYCAMORE CREEK SUB, Chico	Distribution	115.00	12.00	
38	TABLE MOUNTAIN SUB, Oroville	Transmission	230.00	115.00	
39	TABLE MOUNTAIN SUB, Oroville	Transmission	500.00	230.00	13.80
40	TAFT SUB, Taft	Transmission	115.00	70.00	13.20

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	TAFT SUB, Taft	Transmission	115.00	12.00	7.20
2	TASSAJARA SUB, Danville	Distribution	230.00	21.00	7.20
3	TEJON SUB, Leboc	Distribution	70.00	12.00	7.20
4	TEMBLOR SUB, McKittrick	Distribution	115.00	12.00	2.40
5	TEMPLETON SUB, TEMPLETON	Transmission	230.00	70.00	13.20
6	TEMPLETON SUB, TEMPLETON	Transmission	230.00	21.00	7.20
7	TESLA SUB, Tracy	Transmission	230.00	115.00	13.20
8	TESLA SUB, Tracy	Transmission	500.00	230.00	13.20
9	TEVIS SUB, Oildale	Distribution	115.00	21.00	7.20
10	TIDEWATER SUB, Martinez	Distribution	230.00	21.00	
11	TIVY VALLEY SUB, Fresno	Distribution	70.00	12.00	7.20
12	TRACY SUB, Tracy	Distribution	115.00	12.00	4.16
13	TRES VIAS SUB, Oroville	Distribution	60.00	12.00	7.20
14	TRIMBLE SUB, San Jose	Distribution	115.00	12.00	7.20
15	TRIMBLE SUB, San Jose	Distribution	115.00	21.00	7.20
16	TRINITY SUB, Weaverville	Transmission	115.00	60.00	13.20
17	TULARE LAKE SUB, Kettleman	Distribution	70.00	12.00	2.40
18	TULUCAY SUB, Napa	Transmission	230.00	60.00	13.20
19	TULUCAY SUB, Napa	Transmission	60.00	12.00	7.20
20	TUPMAN SUB, Tupman	Distribution	115.00	12.00	7.20
21	TWISSELMAN SUB, Blackwell Corners	Distribution	70.00	12.00	7.20
22	TYLER SUB, Red Bluff	Distribution	60.00	12.00	2.40
23	UKIAH SUB, Ukiah	Distribution	115.00	12.00	7.20
24	URICH SUB, Martinez	Distribution	60.00	4.00	
25	VACA DIXON SUB, Vacaville	Transmission	115.00	60.00	13.20
26	VACA DIXON SUB, Vacaville	Transmission	230.00	115.00	13.20
27	VACA DIXON SUB, Vacaville	Transmission	500.00	230.00	13.80
28	VACA DIXON SUB, Vacaville	Transmission	115.00	12.00	7.20
29	VACAVILLE SUB, Vacaville	Distribution	115.00	12.00	7.20
30	VALLEY SPRINGS SUB, Valley Springs	Transmission	230.00	60.00	13.20
31	VALLEY VIEW SUB, El Sobrante	Distribution	115.00	12.00	
32	VASCO SUB, Livermore	Distribution	60.00	12.00	
33	VASONA SUB, Los Gatos	Distribution	230.00	12.00	7.20
34	VICTOR SUB, Lodi	Distribution	60.00	12.00	2.40
35	VIEJO SUB, Monterey	Distribution	60.00	21.00	7.20
36	VIERRA SUB, Lathrop	Distribution	115.00	17.00	7.20
37	VINEYARD SUB, Pleasanton	Distribution	230.00	21.00	7.20
38	VOLTA #1PH SUB, Shingletown	Distribution	60.00	12.00	2.40
39	WAHTOKE SUB, Reedley	Distribution	115.00	12.00	7.20
40	WASCO SUB, Wasco	Distribution	70.00	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	02/24/2016	End of 2015/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	WATERLOO SUB, Stockton	Distribution	60.00	12.00	2.40
2	WATSONVILLE SUB, Watsonville	Distribution	60.00	12.00	7.20
3	WATSONVILLE SUB, Watsonville	Distribution	60.00	4.00	
4	WEBER SUB, Stockton	Transmission	230.00	60.00	13.20
5	WEBER SUB, Stockton	Transmission	60.00	12.00	7.20
6	WEBER SUB, Stockton	Transmission	230.00	12.00	7.20
7	WEEDPATCH SUB, Weedpatch	Distribution	70.00	12.00	7.20
8	WELLFIELD SUB, Lamont	Distribution	70.00	12.00	2.40
9	WEST FRESNO SUB, Fresno	Distribution	115.00	12.00	7.20
10	WEST LANE SUB, Stockton	Distribution	60.00	12.00	7.20
11	WEST SACRAMENTO SUB, WEST SACRAMENTO	Distribution	115.00	12.00	7.20
12	WESTLEY SUB, Westley	Distribution	60.00	12.00	2.40
13	WESTPARK SUB, Bakersfield	Distribution	115.00	12.00	7.20
14	WHEATLAND SUB, Wheatland	Distribution	60.00	12.00	7.20
15	WHEELER RIDGE SUB, Bakersfield	Transmission	115.00	70.00	13.20
16	WHEELER RIDGE SUB, Bakersfield	Transmission	230.00	70.00	13.20
17	WHEELER RIDGE SUB, Bakersfield	Transmission	70.00	12.00	2.40
18	WHISMAN SUB, Mt. View	Distribution	115.00	12.00	7.20
19	WILLIAMS SUB, Williams	Distribution	60.00	12.00	7.20
20	WILLITS A SUB, Willits	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		83020.00	19289.10	4107.08
37	Transmission only substations		33240.00	12415.00	1701.20
38					
39	Combined Dist Subs < 10 MVA (136 substations)				
40					

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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
90	2					2
27	2					3
60	2					4
11	1					5
49	4	1				6
30	1					7
19	3	1				8
16	1					9
38	2					10
11	1					11
11	3	1				12
16	1					13
16	1					14
27	4	1				15
60	2					16
360	6	1				17
11	3					18
210	3					19
30	1					20
334	4	1				21
840	2					22
90	2					23
25	2					24
16	3	1				25
16	1					26
112	2					27
80	3					28
45	1					29
225	3					30
13	1					31
120	3					32
39	4					33
90	2					34
75	2					35
16	1					36
13	1					37
57	2					38
57	3					39
16	6	1				40

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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					1
400	2		Sync Cond	1	40	2
400	2					3
135	3					4
10	2					5
11	2					6
11	3	1				7
15	3					8
7	6	1	SVC	1	7	9
20	3					10
13	1					11
13	3	1				12
90	2					13
13	1					14
16	1					15
400	2					16
30	1					17
20	3					18
195	3					19
90	3	1				20
840	2					21
120	3					22
90	3					23
21	2					24
76	3					25
90	2					26
45	1					27
30	1					28
60	3	1				29
46	2					30
11	1					31
20	3					32
30	1					33
15	3					34
19	3					35
135	3					36
21	3	1				37
16	1					38
41	2					39
90	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	02/24/2016	End of 2015/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.
11	1					1
6	3	1				2
60	2					3
24	1					4
11	6					5
37	3					6
16	1					7
16	1					8
14	2					9
25	2					10
50	4					11
76	3					12
45	1					13
90	2					14
30	3	1				15
11	1					16
45	1					17
25	2					18
13	1					19
41	2					20
19	3	1				21
16	1					22
21	3	1				23
32	2					24
13	1					25
13	1					26
61	2					27
90	3	1				28
11	3	1				29
135	3					30
29	2					31
135	3					32
16	1					33
20	6	1				34
19	3	1				35
90	2					36
45	1					37
27	2					38
19	3					39
61	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
214	6	1				1
59	3					2
12	1					3
21	6	1				4
120	6	2				5
180	3	1				6
225	3					7
42	3	1				8
290	4	1				9
20	3	1				10
28	4					11
90	3	1				12
46	2					13
16	1					14
13	3	2				15
58	10	3				16
30	1					17
43	2					18
200	1					19
588	4	2				20
7	1					21
29	6	1				22
80	2					23
400	2					24
240	6	1				25
75	2					26
35	3					27
7	1					28
25	3	1				29
90	2					30
19	3	1				31
16	3					32
16	1					33
60	2					34
135	3					35
135	3					36
90	2					37
75	2					38
16	1					39
400	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	02/24/2016	End of 2015/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)	
75	2					1
14	1					2
43	2					3
61	2					4
49	5					5
170	6	1				6
11	3	1				7
135	3	1				8
75	2					9
11	1					10
13	1					11
105	3					12
32	6	1				13
68	3	1				14
180	4					15
25	2	1				16
200	1					17
16	1					18
16	1					19
8	1					20
840	2					21
135	3					22
45	1					23
90	2					24
90	2					25
63	2					26
45	1					27
127	5	1				28
32	2					29
180	4					30
23	2					31
11	1					32
13	1					33
11	3	1				34
13	1					35
21	3	1				36
80	3	1				37
90	2	1				38
13	1					39
50	3					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
60	2					1
30	1					2
60	2					3
225	3					4
30	1					5
22	2					6
25	3					7
50	2					8
11	1					9
21	3	1				10
60	2					11
45	1					12
19	3	1				13
60	2					14
90	3					15
32	2					16
25	4					17
49	4	1				18
600	2					19
823	4	1				20
60	2					21
16	1					22
25	1					23
13	1					24
16	1					25
21	3	1	SVC	1	15	26
21	3	1				27
117	3	1				28
120	3					29
1122	3	1				30
45	1					31
19	3					32
22	4					33
19	3					34
16	1					35
255	4	1				36
30	1					37
32	2					38
7	1					39
80	3					40

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PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
840	2					1
16	1					2
22	2					3
27	2					4
81	3					5
90	2					6
19	3	1				7
38	3					8
60	2					9
32	2					10
12	7	1				11
43	2					12
21	3					13
50	5					14
67	5					15
16	1					16
13	2					17
12	1					18
29	2					19
60	2					20
19	2					21
16	3					22
134	3					23
308	4					24
180	3	1				25
28	4					26
50	3	1				27
13	1					28
1260	3		Sync Cond	2	80	29
1260	3					30
150	2					31
90	2					32
77	3					33
60	2					34
90	2					35
70	2					36
25	1					37
16	1					38
40	1					39
13	3	1				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) 02/24/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
90	2					1
16	1					2
133	6					3
77	3					4
11	1					5
4	1					6
4	1					7
400	2		SVC	1	50	8
400	2					9
20	3					10
400	2					11
823	4	1				12
46	2					13
16	1					14
13	1					15
16	1					16
29	2					17
90	2					18
39	2					19
105	3					20
400	2					21
22	1					22
11	1					23
76	3					24
30	1					25
60	2					26
120	3					27
90	2					28
400	2					29
1260	3					30
11	3	1				31
11	3					32
47	3					33
90	3	1				34
90	2					35
135	3					36
23	2					37
19	3					38
400	2					39
840	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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	2					1
170	6	1				2
25	3	1				3
90	2					4
75	2					5
57	3					6
30	1					7
90	3					8
165	3					9
14	2					10
145	5	1				11
19	3					12
75	2					13
60	2					14
91	3					15
19	3					16
27	2					17
25	6					18
45	1					19
11	3					20
100	3					21
400	2					22
30	1	1				23
46	2					24
21	3	1				25
5	3	1				26
45	1					27
45	1					28
51	3					29
334	4					30
840	3	1				31
13	3	1				32
840	2					33
32	2					34
13	3	1				35
43	2					36
21	3	1				37
5	3	1				38
29	2					39
19	3					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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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
71	7					2
30	1					3
21	2					4
45	1					5
45	1					6
105	3					7
135	3					8
31	3	1				9
135	8	1				10
11	3					11
32	2					12
13	3	1				13
49	4	1				14
17	3	1				15
1243	5	1	Sync Cond	2	80	16
1243	5	1				17
90	2					18
21	2					19
32	2					20
105	3					21
13	4	1				22
45	1					23
170	3					24
280	4	1				25
5	3	1				26
90	3	1				27
30	1					28
32	2					29
13	2					30
50	3					31
45	1					32
45	1					33
21	3	1				34
840	2					35
45	1					36
3366	9	2				37
1630	10	1				38
11	1					39
34	4	1				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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1260	3					1
3364	9	2				2
23	2					3
90	3					4
60	2					5
6	3	1				6
90	2					7
75	2					8
11	1					9
14	3	1				10
43	2					11
90	2					12
45	1					13
200	1					14
134	3	1				15
1260	3					16
135	3					17
29	2					18
11	3	1				19
958	7	1				20
45	1					21
120	3					22
30	1					23
269	3	1				24
16	1					25
105	3					26
1680	4					27
1122	3	1				28
115	3					29
135	3					30
16	1					31
68	7	1				32
200	4	1				33
150	2					34
1646	8	1	SVC	1	200	35
80	3					36
1646	8	1				37
90	2					38
20	4	1				39
29	2					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
41	4					1
16	1					2
32	2					3
45	1					4
45	1					5
90	2					6
30	6					7
45	1					8
23	2					9
43	3					10
225	6					11
175	4					12
146	5	1				13
38	3	1				14
135	3					15
90	3					16
75	2					17
42	6	1				18
31	4					19
40	7					20
18	4					21
60	2					22
16	1					23
6	3					24
25	7					25
11	1					26
60	3					27
22	3					28
45	1					29
41	2					30
25	2					31
5	3	1				32
16	1					33
23	2					34
168	3	1				35
420	1					36
11	1					37
45	1					38
840	2					39
30	1					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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	1					1
45	1					2
30	1					3
45	1					4
90	3					5
135	3					6
195	3					7
14	6	1				8
80	3	1				9
50	2					10
13	1					11
61	2					12
58	4					13
57	5	1				14
45	1					15
22	4					16
135	3					17
840	2					18
95	3					19
41	4	1				20
30	1					21
30	1					22
39	2					23
135	3					24
45	1					25
13	1					26
11	1					27
16	1					28
65	2					29
32	2					30
45	1		StatCom	2	8	31
45	1					32
45	1					33
11	1					34
32	2					35
16	1					36
25	6					37
30	1					38
16	4					39
16	1					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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
823	4	1				1
19	3					2
50	5					3
23	3					4
70	5					5
21	6	1				6
190	4	1				7
30	1					8
30	1					9
90	2					10
45	1					11
11	1					12
4	1					13
3	1					14
14	2					15
90	2					16
32	2					17
35	4					18
11	3					19
254	6					20
28	1					21
11	3	1				22
90	2					23
73	4	1				24
23	1					25
27	4	1				26
30	1					27
90	2					28
16	1					29
1122	3	1				30
148	3					31
400	2					32
90	2					33
11	3	1				34
11	3	1				35
30	1					36
19	3					37
29	2					38
12	3	1				39
182	3		SVC	1	240	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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
182	3					1
100	1					2
823	4	1				3
180	4					4
98	2					5
375	5					6
410	6					7
345	3					8
18	2					9
40	2					10
30	1					11
180	4					12
160	4					13
200	1					14
135	3					15
1260	3		Sync Cond	2	88	16
156	4					17
1260	3					18
45	1					19
9	3	1				20
16	1					21
45	1					22
117	3					23
90	3	1				24
300	4					25
30	3	1				26
60	2					27
75	2					28
27	2					29
12	3					30
135	3					31
41	2					32
157	3					33
21	3	1				34
5	3	1				35
90	3	1				36
30	1					37
90	3	1				38
30	1					39
13	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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27	3	1				1
11	1					2
61	2					3
16	1					4
15	3	1				5
60	2					6
32	2					7
49	4					8
19	6					9
806	6	1				10
30	1					11
75	6					12
11	1					13
60	2					14
25	3					15
19	1					16
13	3	1				17
13	1					18
25	2					19
600	2					20
150	2					21
51	4	1				22
11	1					23
105	3					24
11	3	1				25
225	3					26
75	2					27
105	3					28
22	6					29
17	2					30
45	1					31
90	2					32
21	3	1				33
120	3					34
13	1					35
140	3					36
90	3					37
1008	5	1				38
1122	3	1				39
162	4					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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27	2					1
225	3					2
49	4					3
21	3	1				4
175	1					5
90	2					6
806	6	1				7
3366	9	2				8
90	2					9
150	2					10
13	1					11
106	4					12
16	1					13
90	2					14
90	2					15
90	3	1				16
24	4	2				17
400	2					18
30	1					19
61	2					20
32	2					21
19	6					22
29	2					23
10	3	1				24
290	4	1				25
1094	8					26
2244	6	1				27
105	3					28
120	3					29
334	4	1				30
29	2					31
17	6					32
90	2					33
30	1					34
60	2					35
90	2					36
150	2	1				37
21	3	1				38
60	2					39
20	3					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	02/24/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
16	1					2
8	1					3
476	7					4
50	2					5
90	2					6
30	1					7
24	4					8
135	3					9
30	1					10
105	3					11
29	2					12
105	3					13
44	4	1				14
60	3	1				15
334	4	1				16
19	3					17
105	3					18
27	2					19
19	3	1				20
30	1					21
11	3	1				22
14	3	1				23
689	4	1				24
14	1					25
120	3					26
23	3					27
135	3					28
56	3					29
135	3					30
13	1					31
120	3					32
11	1					33
27	2					34
-59						35
100048	1842	167		14	808	36
73538	585	78		10	545	37
						38
706	358	60				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.: 39 Column: e

2.4 and 7.2

Schedule Page: 426.2 Line No.: 31 Column: e

2.4 and 7.2

Schedule Page: 426.4 Line No.: 5 Column: e

2.4 and 7.2

Schedule Page: 426.6 Line No.: 14 Column: e

2.4 and 7.2

Schedule Page: 426.7 Line No.: 17 Column: e

2.4 and 7.2

Schedule Page: 426.10 Line No.: 35 Column: k

200 to 221

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: 426.16 Line No.: 3 Column: e

7.2 and 2.4

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 91 Transmission Substations and 603 Distribution Substations. This represents a total of 694 physical transmission and distribution substations (91+603=694). 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 662 substations with distribution transformer banks. (603+59 = 662).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	02/24/2016	End of 2015/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	Corporation A&G Allocations			
4	Total - Administrative & General Expenses		923, 426.4, 426.5	53,180,749
5				53,180,749
6				
7	Rent Expense	Eureka Energy Company	532.0	291,509
8				
9	Total non-power goods/srvs provided by Affiliates			53,472,258
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			832,903
23	Administration			269,001
24	Banking Services			53,266
25	Taxes Services			345,221
26	Business Planning Services			65,026
27	Compliance & Ethics			2,018
28	Corporate Relations Support			1,376,056
29	Corporate Sustainability Support			247,621
30	Consulting Services			8,094
31	Employee Transfer Fees			598,112
32	Financial Forecasting and Analysis			176,097
33	Fleet Services			111,081
34	Human Resources Support			273,888
35	Interest Income			3,586
36	Internal Audit Services			6,804
37	Investor Relations Support			7,578
38	Insurance Support			8,061
39	Information Technology			512,731
40	Legal Services			76,058
41	Misc. Expense			27
42	Permit Expense			1,853
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	02/24/2016	End of 2015/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.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21		PG&E Corporation	930.2	
22	Risk and Audit			6,749
23	Record Center			1,454
24	Real Estate and Facility			624,924
25	Security Support			365,520
26	Strategy Support			79,188
27				
28				
29	Total - A&G Direct Charges to PG&E Corp			6,052,916
30				
31		FUELCO LLC	930.2	
32	Accounting			26,767
33	CFO Support			5,819
34	Fuel Purchasing Support			802,396
35	Legal Services			23,454
36	Supply Chain Support			4,248
37				
38	Total - A&G Direct Charges to FUELCO LLC			862,684
39				
40	Total Non-power goods/Srvs Provided to Affiliates			6,915,601
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 cost
(c) Affiliate Headcount/Total Consolidate Headcount

(B) Capitalization (100%)
Affiliate Capitalization/Total Consolidated Capitalization

(C) Headcount (99.98%)
Affiliate Headcount/Total consolidated headcount

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