2019
ANNUAL REPORT

of

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000, B7C
San Francisco, CA 94177

to the

Public Utilities Commission
of the
State of California
For the Year Ended December 31, 2019

Volume No. 1 (Form 1)

Deloitte.

Deloitte & Touche LLP
555 Mission Street
Suite 1400
San Francisco, CA 94105
USA

Tel:+1 415 783 4000
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Pacific Gas and Electric Company

We have audited the accompanying financial statements of Pacific Gas and Electric Company (the "Company"), which comprise the balance sheet—regulatory basis as of December 31, 2019, the related statements of income—regulatory basis, retained earnings—regulatory basis, and cash flows—regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America.

Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Pacific Gas & Electric Company as of December 31, 2019, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

As discussed in the introduction to Note 1 to the FERC financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Emphasis of Matter Regarding Going Concern

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Notes 1 and 14 to the financial statements, the Company suffered material losses as a result of the 2017 Northern California wildfires and the 2018 Camp fire, which contributed to the Company's decision to voluntarily file for bankruptcy. These circumstances raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Notes 1 and 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty. Our opinion is not modified with respect to this matter.

Bankruptcy Proceedings

As discussed in Note 2 to the financial statements, on January 29, 2019, the Company has voluntarily filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. The accompanying financial statements do not purport to reflect or provide for the consequences of the bankruptcy proceedings. In particular, such financial statements do not purport to show (1) as to assets, their realizable value on a liquidation basis or their availability to satisfy liabilities; (2) as to shareholder accounts, the effect of any changes that may be made in the capitalization of the Company; or (3) as to operations, the effect of any changes that may be made in its business. Our opinion is not modified with respect to this matter.

Restricted Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

March 25, 2020

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	End of 2019/Q4

03 Previous Name and Date of Change *(if name changed during year)*
PACIFIC GAS AND ELECTRIC COMPANY / /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
77 BEALE STREET, P.O BOX 770000, SAN FRANCISCO, CA 94177

05 Name of Contact Person	06 Title of Contact Person
JENNIFER GARBODEN	DIRECTOR, CORP ACCOUNTING

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

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(415) 973-5456	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
DAVID THOMASON	David Thomason	
02 Title VP, CONTROLLER, UTILITY CFO	DAVID THOMASON	03/2 5 /2020

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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	NONE
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	NONE
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	NONE
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

GENERAL INFORMATION

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

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

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

California, October 1905

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

Not Applicable

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

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

State of California only.

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

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

CONTROL OVER RESPONDENT

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

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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				
2	Standard Pacific Gas Line Incorporated	Engaged in the transportation	85.71	
3		of natural gas in California.		
4		The Utility owns an 85.71%		
5		interest and Chevron Pipe		
6		Line Company owns the		
7		remaining 14.29% interest.		
8				
9				
10				
11				
12	Morro Bay Mutual Water Company	Formed to jointly hold	50	2
13		property rights in connection		
14		with the divestiture of the		
15		Morro Bay Power Plant.		
16				
17	Moss Landing Mutual Water Company	Formed to jointly hold	33	3
18		propert rights in connection		
19		with the divestiture of the		
20		Moss Landing Power Plant.		
21				
22	Alaska Gas Exploration Associates	Formed to explore,	100	4
23		develop, produce, acquire,		
24		and market oil and gas		
25		reserves in Alaska.		
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	STARS Alliance, LLC	Formed to increase efficiency	25	5
2		and reduce costs related to		
3		the operation of the members		
4		nuclear generation		
5		facilities.		
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Schedule Page: 103 Line No.: 19 Column: d

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

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

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

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

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

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

Currently inactive.

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

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

Waiting for confirmation of withdrawal from Texas.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Senior Vice President and General Counsel	Janet C. Loduca	636,226
2	Senior Vice President, Human Resources	Dinyar B.Mistry	547,141
3	Senior Vice President, Generation and Chief Nuclear	James M. Welsch	521,771
4	Officer		
5	Senior Vice President and Chief Customer Officer	Loraine M. Giammona	496,576
6	Senior Vice President, Electric Operations	Michael A. Lewis	474,855
7	Senior Vice President, Chief Ethics & Compliance	Julie M. Kane	473,200
8	Officer and Deputy General Counsel		
9	Senior Vice President and Chief Information Officer	Kathleen B. Kay	415,000
10	Senior Vice President, Energy Policy & Procurement	Fong Wan	413,800
11	Chief Executive Officer and President, Pacific Gas and	Andrew M. Vesey	371,212
12	Electric Company		
13	Vice President, Controller, and Chief Financial Officer	David S. Thomason	325,000
14	Pacific Gas and Electric Company		
15	Senior Vice President, Gas Operations	Melvin Christopher	294,404
16	Senior Vice President and Advisor to Utility	Jesus Soto, Jr.	288,119
17	Senior Vice President, Energy Supply & Policy	Steven Malnight	151,337
18	Senior Vice President and Advisor to Utility	Patrick M. Hogan	31,363
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			

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

Ms. Loduca, formerly Senior Vice President and Deputy General Counsel, became Senior Vice President and Interim General Counsel on January 13, 2019 and became Senior Vice President and General Counsel on May 2, 2019.

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

Mr. Mistry, formerly Senior Vice President, Human Resources and Chief Diversity Officer, became Senior Vice President, Human Resources on August 23, 2019. The role of Senior Vice President, Human Resources is no longer an executive officer of Pacific Gas and Electric Company, effective December 31, 2019.

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

Mr. Welsch, formerly Vice President, Nuclear Generation and Chief Nuclear Officer, became Senior Vice President, Generation and Chief Nuclear Officer on May 16, 2019.

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

The role of Senior Vice President and Chief Customer Officer is no longer an executive officer of Pacific Gas and Electric Company, effective December 31, 2019.

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

Mr. Lewis, formerly Vice President, Electric Distribution, became Senior Vice President, Electric Operations on January 8, 2019.

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

The role of Senior Vice President, Chief Ethics & Compliance Officer and Deputy General Counsel is no longer an executive officer of Pacific Gas and Electric Company, effective December 31, 2019.

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

The role of Senior Vice President and Chief Information Officer is no longer an executive officer of Pacific Gas and Electric Company, effective December 31, 2019.

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

The role of Senior Vice President, Energy Policy & Procurement is no longer an executive officer of Pacific Gas and Electric Company, effective December 31, 2019.

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

Mr. Christopher, formerly Vice President, Gas Transmission & Distribution Operations, became Vice President, Gas Operations on June 3, 2019 and became Senior Vice President, Gas Operations on October 1, 2019. Mr. Christopher's employment ended November 2, 2019.

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

Mr. Soto, formerly Senior Vice President, Gas Operations, became Senior Vice President and Advisor to Utility on June 3, 2019. Mr. Soto's employment ended July 3, 2019.

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

Mr. Malnight's employment ended April 13, 2019.

Schedule Page: 104 Line No.: 18 Column: b

Mr. Hogan, formerly Senior Vice President, Electric Operations, became Senior Vice President and Advisor to Utility on January 8, 2019. Mr. Hogan's employment ended January 29, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Richard R. Barrera ***	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Jeffrey L. Bleich **	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	Nora Mead Brownell ***	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
12		
13	Frederick W. Buckman	c/o PG&E Corporation
14		77 Beale Street, 32nd Floor
15		San Francisco, CA 94105
16		
17	Cheryl F. Campbell ***	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
20		
21	Lewis Chew	c/o PG&E Corporation
22		77 Beale Street, 32nd Floor
23		San Francisco, CA 94105
24		
25	Fred J. Fowler	c/o PG&E Corporation
26		77 Beale Street, 32nd Floor
27		San Francisco, CA 94105
28		
29	William D. Johnson	c/o PG&E Corporation
30		77 Beale Street, 32nd Floor
31		San Francisco, CA 94105
32		
33	Richard C. Kelly	c/o PG&E Corporation
34		77 Beale Street, 32nd Floor
35		San Francisco, CA 94105
36		
37	Roger H. Kimmel	c/o PG&E Corporation
38		77 Beale Street, 32nd Floor
39		San Francisco, CA 94105
40		
41	Michael J. Leffell ***	c/o PG&E Corporation
42		77 Beale Street, 32nd Floor
43		San Francisco, CA 94105
44		
45	Kenneth Liang	c/o PG&E Corporation
46		77 Beale Street, 32nd Floor
47		San Francisco, CA 94105
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Richard A. Meserve	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Dominique Mielle ***	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	Forrest E. Miller	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
12		
13	Benito Minicucci	c/o PG&E Corporation
14		77 Beale Street, 32nd Floor
15		San Francisco, CA 94105
16		
17	Meridee A. Moore ***	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
20		
21	Eric D. Mullins	c/o PG&E Corporation
22		77 Beale Street, 32nd Floor
23		San Francisco, CA 94105
24		
25	Rosendo G. Parra	c/o PG&E Corporation
26		77 Beale Street, 32nd Floor
27		San Francisco, CA 94105
28		
29	Barbara L. Rambo	c/o PG&E Corporation
30		77 Beale Street, 32nd Floor
31		San Francisco, CA 94105
32		
33	Kristine M. Schmidt ***	c/o PG&E Corporation
34		77 Beale Street, 32nd Floor
35		San Francisco, CA 94105
36		
37	Anne Shen Smith	c/o PG&E Corporation
38		77 Beale Street, 32nd Floor
39		San Francisco, CA 94105
40		
41	William L. Smith	c/o PG&E Corporation
42		77 Beale Street, 32nd Floor
43		San Francisco, CA 94105
44		
45	Andrew M. Vesey, Chief Executive Officer and President,	c/o PG&E Corporation
46	Pacific Gas and Electric Company ***	77 Beale Street, 32nd Floor
47		San Francisco, CA 94105
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Geisha Williams	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Alejandro D. Wolff	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	John M. Woolard	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
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		
47		
48		

Schedule Page: 105 Line No.: 13 Column: a
Fredrick W. Buckman resigned on 11/12/2019.

Schedule Page: 105 Line No.: 21 Column: a
Lewis Chew resigned on 4/9/2019.

Schedule Page: 105 Line No.: 33 Column: a
Richard C. Kelly resigned on 4/22/2019.

Schedule Page: 105 Line No.: 37 Column: a
Roger H. Kimmel resigned on 1/14/2019.

Schedule Page: 105 Line No.: 45 Column: a
Kenneth Liang resigned on 9/7/2019.

Schedule Page: 105.1 Line No.: 1 Column: a
Richard A. Meserve resigned on 4/9/2019.

Schedule Page: 105.1 Line No.: 9 Column: a
Forrest E. Miller resigned on 4/9/2019.

Schedule Page: 105.1 Line No.: 13 Column: a
Benito Minicucci resigned on 4/9/2019.

Schedule Page: 105.1 Line No.: 25 Column: a
Rosendo G. Parra resigned on 4/9/2019.

Schedule Page: 105.1 Line No.: 29 Column: a
Barbara L. Rambo resigned on 4/9/2019.

Schedule Page: 105.1 Line No.: 37 Column: a
Anne Shen Smith resigned on 4/9/2019.

Schedule Page: 105.2 Line No.: 1 Column: a
Geisha Williams resigned on 1/13/2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	PG&E FERC Electric Tariff Volume No. 5	ER19-13-000
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		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	20191127-5053	11/26/2019	ER19-13-000	Annual Formula Transmission Rate	PG&E FERC Electric Tariff Volume No.
2	20191127-5053	11/26/2019	ER19-1816-00	Annual Formula Transmission Rate	PG&E FERC Electric Tariff Volume No.
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	03/25/2020	End of 2019/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		
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				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

PACIFIC GAS AND ELECTRIC COMPANYs
IMPORTANT CHANGES DURING THE YEAR

For the Quarter Ended December 31, 2019

1. **Changes in and important additions to franchise rights:**

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

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

   None.

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

   Sale:

   None.

   Purchase:

   None.

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

   None.

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

   Electric:

   On January 31, 2019, the Owens Brockway 115 kV Tap Removal Project was released to operations. This project, located in Alameda County, removed the Owens Brockway 115 kV Tap to coordinate the East Shore - Oakland J 115 kV Line Reconductoring project and because the transmission customer served off the tap opted to be served off the distribution system.

   On April 24, 2019, the Borden 230 kV Voltage Support Project was released to operations. This project, located in Madera County, looped the Wilson-Gregg 230 kV lines into the Borden 230 kV Substation. This project was built to increase system voltage & reliability, and to increase capacity for future interconnection resources.

   On April 25, 2019, the Bellota 230 kV Shunt Reactor Project was released to operations. This project, located in San Joaquin County, installed 100 MVAR shunt reactor at the Bellota 230 kV Substation. This project was built to mitigate high voltages in PG&E's Stockton Division.

   On May 24, 2019, the Ripon 115 kV New Line Project was released to operations. This project, located in San Joaquin County, installed a new 4.7-mile 115 kV transmission line from Ripon Substation to the Riverbank Switching Station - Manteca 115 kV Line. The new 115 kV transmission line will provide Ripon Substation with two sources, improving electric transmission reliability for customers served by Ripon Substation.

On August 16, 2019, the Ignacio 230 kV Substation Shunt Reactor project was released to operations. This project, located in Marin County, installed two 230 kV, 75 MVar shunt reactors at the Ignacio 230 kV Substation. This project will minimize high voltages and impacts to the North Bay system and will significantly improve operational and maintenance flexibility in the area.

On November 2, 2019, the Padre Flat Switching Station was released to operations. This project, located in Merced County, constructed a new 2-bay, 5 circuit breaker-and-a-half (BAAH) 230 kV Switching Station. This project was built to facilitate the interconnection of a 200 MW solar generation by Wright Solar to Pacific Gas and Electric Los Banos - Panoche 230 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:

On April 3, 2019, PG&E drew the $1.5B term loan available through the Debtor-In-Possession (DIP) facility and subsequently repaid the $350M draw on the DIP revolving credit facility. The $1.5B term loan is still outstanding at December 31, 2019.

b) Bank Credit Facilities:

At December 31, 2019, the Utility had $665 million of letters of credit outstanding under the DIP revolver and $27 million under the pre-petition revolver.

Non-bankruptcy short-term borrowings are authorized by CPUC Decision No. 09-05-002.
Bankruptcy short-term borrowings are authorized by CPUC Decision No. 19-01-025.

c) Surety Bonds and Financial Guarantees Backed by Insurance:

From October 1, 2019 to December 31, 2019 $13,955,624 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of December 31, 2019, there was a total of $202,037,340.19 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, 2019, the Utility has no outstanding future capital commitments to unregulated subsidiaries and affiliates.

e) Preferred stock repayments:

None.

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

None.

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

None.

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

Refer to Part I, Item 3 in PG&E Corporation and the Utility's joint Annual Report on Form 10-K for the year ended December 31, 2019, which describes certain legal proceedings pursuant to Item 103 of Regulation S-K of the Securities Exchange Act of 1934, as amended. Four copies of the Form 10—K report are filed in accordance with Instruction III(c) of Instructions For Filing the FERC Form No. 1.

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

"Five Percent Owners"

During the fourth quarter of 2019, two beneficial owners of at least 5 percent of PG&E Corporation common stock as of December 31, 2019 provided services to PG&E Corporation, Pacific Gas and Electric Company ("Utility"), and related entities. These entities were identified based solely on a review of Schedule 13Gs (or any amendments) filed with the Securities and Exchange Commission as of the date of this report.

- The Vanguard Group ("Vanguard") provided asset management services to the trusts securing benefits in the event of a change in control, and the PG&E Corporation Foundation. 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. Actual fees paid in 2019 were $83,000.

  During 2019, Vanguard did NOT provide services in excess of the $120,000 disclosure threshold set forth in SEC Reg. S-K, Item 404(a).

- Gallagher Financial Advisory Services ("Gallagher") provided independent fiduciary services to the PG&E Corporation Stock Fund in the 401(k) Plan, and, solely by reason of that fact, is deemed to beneficially own the fund's shares (and thereby is deemed a five percent owner of PG&E Corporation common stock). Gallagher was selected from among five different candidates to provide these services, and any provider similarly would have become a five percent owner if selected as the independent fiduciary. The terms of the engagement are consistent with those obtainable in arm's-length negotiations. Actual fees paid in 2019 were less than $50,000.

  During 2019, Gallagher did NOT provide services in excess of the $120,000 disclosure threshold set forth in SEC Reg. S-K, Item 404(a).

"Immediate Family Members"

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

We expect that the value of payments to Ms. Thomason for the period January 2019 through March 2020 (assuming she remains employed with the Utility during that period) will exceed the $120,000 disclosure threshold set forth in SEC Reg S-K. Item 404(a).

11. (Reserved)

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions to 1 to 11 above, such notes may be included on this page.

Not applicable.

13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period:

Directors

The following individuals were elected as Directors of the Utility:

- Richard R. Barrera, Director
- Jeffrey L. Bleich, Director
- Nora Mead Brownell, Director
- Frederick W. Buckman, Director
- Cheryl F. Campbell, Director
- William D. Johnson, Director
- Michael J. Leffell, Director
- Kenneth Liang, Director
- Dominique Mielle, Director
- Meridee A. Moore, Director
- Kristine M. Schmidt, Director
- William L. Smith, Director
- Andrew M. Vesey, Director
- Alejandro D. Wolff, Director
- John M. Woolard, Director

The following individuals are no longer Directors of the Utility:

- Frederick W. Buckman, Director
- Lewis Chew, Director
- Richard C. Kelly, Director
- Roger H. Kimmel, Director
- Kenneth Liang, Director
- Richard A. Meserve, Director
- Forrest E. Miller, Director
- Benito Minicucci, Director
- Rosendo G. Parra, Director
- Barbara L. Rambo, Director
- Anne Shen Smith, Director
- Geisha J. Williams, Director

Officers

The following individuals became officers of the Utility:

- Jeffrey L. Bleich, Chair of the Board
- Andrew M. Vesey, Chief Executive Officer and President
- Ahmad Ababneh, Vice President, Electric Operations Major Projects and Programs
- E. Christine Cowsert, Vice President, Gas Asset Management and System Operations
- Thomas M. French, Vice President, Electric Transmission Operations
- Paula A. Gerfen, Site Vice President, Diablo Canyon Power Plant
- Peter Kenny, Vice President, Gas Transmission and Distribution Construction
- Kenneth J. Wells, Vice President, Electric Distribution Operations
- J. Ellen Conti, Assistant Corporate Secretary

The following individuals' titles changed:

- Melvin J. Christopher, Senior Vice President, Gas Operations, (formerly Vice President, Gas Operations; formerly Vice President, Gas Transmission and Distribution Operations)
- Patrick M. Hogan, Senior Vice President and Advisor (formerly Senior Vice President, Electric Operations)
- Michael A. Lewis, Senior Vice President, Electric Operations (formerly Vice President, Electric Distribution Operations)
- Janet C. Loduca, Senior Vice President and General Counsel (formerly Senior Vice

President and Interim General Counsel; formerly Senior Vice President and Deputy General Counsel)

- Dinyar B. Mistry, Senior Vice President, Human Resources (formerly Senior Vice President, Human Resources and Shared Services; formerly Senior Vice President, Human Resources, Shared Services and Chief Diversity Officer; formerly Senior Vice President, Human Resources and Chief Diversity Officer)
- James M. Welsch, Senior Vice President, Generation and Chief Nuclear Officer (formerly Senior Vice President and Chief Nuclear Officer; formerly Vice President, Nuclear Generation and Chief Nuclear Officer)
- Valerie J. Bell, Vice President, Information Technology Applications and Infrastructure (formerly Vice President, Information Technology Operations)
- Robert S. Kenney, Vice President, State and Regulatory Affairs (formerly Vice President, Regulatory Affairs)
- Mary K. King, Vice President Human Resources and Chief Diversity Officer (formerly Vice President, Human Resources)
- Roy M. Kuga, Vice President, Energy Policy and Procurement Bankruptcy Strategy (formerly Vice President, Grid Integration and Innovation)
- Jamie L. Martin, Vice President and Chief Procurement Officer (formerly Vice President, Finance and Planning)
- Gun S. Shim, Vice President (formerly Vice President and Chief Procurement Officer)

- Sumeet Singh, Vice President, Asset, Risk Management and Community Wildfire Safety Program (formerly Vice President, Community Wildfire Safety Program)
- Bonnie B. Titone, Vice President, Information Technology Products and Enterprise Platforms (formerly Vice President, Business Technology)
- Andrew K. Williams, Vice President Shared Services (formerly Vice President, Land and Environmental Management)

The following individuals are no longer officers of the Utility:

- Forrest E. Miller, Chair of the Board
- Melvin J. Christopher, Senior Vice President, Gas Operations
- Patrick M. Hogan, Senior Vice President and Advisor
- Steven E. Malnight, Senior Vice President, Energy Supply and Policy
- Jesus Soto, Jr., Senior Vice President, Gas Operations
- Valerie J. Bell, Vice President, Information Technology Applications and Infrastructure
- Mark T. Caron, Vice President, Tax
- Bernard A. Cowens, Vice President and Chief Security Officer
- Kevin J. Dasso, Vice President, Electric Asset Management
- Jon A. Franke, Vice President, Safety and Health and Chief Safety Officer
- Travis T. Kiyota, Vice President, California External Affairs
- Gregg L. Lemler, Vice President, Electric Transmission Operations
- Scott T. Sanford, Vice President, Customer Operations
- Gun S. Shim, Vice President
- Bonnie B. Titone, Vice President, Information Technology Products and Enterprise Platforms
- Eileen O. Chan, Assistant Corporate Secretary

Major Security Holders

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

- Cede & Co., C/O DTCC-Transfer Operation Dept., 570 Washington Blvd Floor 1, Jersey City, NJ 08857, increased its share ownership from 9,632,045 shares as of December 31, 2018 to 9,710,090 shares as of December 31, 2019. (Approximately 94 percent of the total preferred shares outstanding).

- Jason L. Roy, 5646 Brady Joseph Ln, Iowa, LA 70647 is no longer a major holder.
- Hal H. Nelson TR UA Jun 27 90 The Nelson Living Survivors A Trust, 2833 S Harbor Blvd, Oxnard, CA 93035-3953 is no longer a major holder.
- Josephine S. Allen TR UDT Dec 4 91, 118 Scenic Dr, Orinda, CA 94563-3414 became a major holder with 7,300 shares of preferred stock.
- James G. Richards, 1938 Yale Ave E Apt 28, Seattle, WA 98102-3625 became a major holder with 6,900 shares of preferred stock.

Dividend Payments

Refer to Note 6, Equity, of the Notes to Financial Statements on page 122-123 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.

On January 29, 2019, PG&E Corporation and the Utility filed the Chapter 11 Cases with the Bankruptcy Court. PG&E Corporation and the Utility continue to operate their business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. On January 31, 2019, the Bankruptcy Court approved, on an interim basis, certain motions (the "First Day Motions") authorizing, but not directing, PG&E Corporation and the Utility to, among other things, secure $5.5 billion of debtor-in-possession financing. See Note 5 in the Notes to the Financial Statements included in pages 122-123 for further discussion of the DIP Facilities, which provide up to $5.5 billion in financing

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	93,917,917,269	86,967,343,203
3	Construction Work in Progress (107)	200-201	2,672,175,058	2,562,027,669
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		96,590,092,327	89,529,370,872
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	39,506,642,610	37,353,599,037
6	Net Utility Plant (Enter Total of line 4 less 5)		57,083,449,717	52,175,771,835
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	134,676,856	233,949,233
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		397,424,984	427,381,622
10	Spent Nuclear Fuel (120.4)		2,566,969,545	2,359,998,526
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,743,468,286	2,630,936,779
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		355,603,099	390,392,602
14	Net Utility Plant (Enter Total of lines 6 and 13)		57,439,052,816	52,566,164,437
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		55,907,325	55,907,325
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		29,974,881	29,171,933
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	48,216,341	50,082,345
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	361,842,950	355,147,460
24	Other Investments (124)		0	10,942
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		3,212,389,977	2,729,720,970
29	Special Funds (Non Major Only) (129)		879,638,841	545,313,624
30	Long-Term Portion of Derivative Assets (175)		123,756,001	165,299,922
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,655,818,991	3,874,747,196
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		294,434,921	71,327,413
36	Special Deposits (132-134)		7,195,190	6,886,597
37	Working Fund (135)		147,415	147,415
38	Temporary Cash Investments (136)		824,500,000	1,220,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,391,312,162	1,273,685,556
41	Other Accounts Receivable (143)		3,075,983,285	3,128,236,294
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		58,239,935	56,198,372
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		62,212,613	34,585,453
45	Fuel Stock (151)	227	961,981	1,566,341
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	549,615,749	442,660,412
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	409,110,109	396,185,501

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		361,842,950	355,147,460
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		95,650,896	108,986,991
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		410,148,517	305,102,547
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,560,329	3,281,579
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		968,707,535	1,000,028,952
62	Miscellaneous Current and Accrued Assets (174)		185,743,895	102,494,054
63	Derivative Instrument Assets (175)		153,330,724	208,704,537
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		123,756,001	165,299,922
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		7,886,776,435	7,727,233,888
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		693,998	124,158,942
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	68,590,956	68,809,105
72	Other Regulatory Assets (182.3)	232	7,027,240,817	5,845,482,579
73	Prelim. Survey and Investigation Charges (Electric) (183)		-558	162,540
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)		1,358,396	174,950
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	45,196,485	26,073,137
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)		77,021,591	93,374,528
82	Accumulated Deferred Income Taxes (190)	234	9,503,725,902	5,025,590,626
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		16,723,827,587	11,183,826,407
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		86,761,383,154	75,407,879,253

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	1,321,874,045	1,321,874,045
3	Preferred Stock Issued (204)	250-251	257,994,575	257,994,575
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,805,194,230	1,805,194,230
7	Other Paid-In Capital (208-211)	253	6,780,547,928	6,780,547,928
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	6,916,899	6,916,899
10	(Less) Capital Stock Expense (214)	254b	28,951,886	28,951,886
11	Retained Earnings (215, 215.1, 216)	118-119	-4,735,473,388	2,884,435,643
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-59,869,210	-58,010,567
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)	1,017,789	-986,708
16	Total Proprietary Capital (lines 2 through 15)		5,335,417,184	12,955,180,361
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	19,887,100,000	18,387,100,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	13,404,631
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	76,509,009
24	Total Long-Term Debt (lines 18 through 23)		19,887,100,000	18,323,995,622
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,732,629,877	9,012,994
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		26,007,532,982	14,641,225,188
29	Accumulated Provision for Pensions and Benefits (228.3)		1,914,041,383	2,040,734,062
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,530,158,186	1,434,278,826
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		124,040,367	88,211,315
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		5,853,792,194	5,994,342,481
35	Total Other Noncurrent Liabilities (lines 26 through 34)		37,162,194,989	24,207,804,866
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		3,138,570,758	3,135,000,001
38	Accounts Payable (232)		3,902,787,143	2,651,188,423
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		118,946,829	38,940,769
41	Customer Deposits (235)		180,930,636	235,799,401
42	Taxes Accrued (236)	262-263	466,656,094	360,498,405
43	Interest Accrued (237)		967,014,530	234,978,351
44	Dividends Declared (238)		0	16,235,704
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		30,322,243	30,123,144
48	Miscellaneous Current and Accrued Liabilities (242)		768,630,901	411,182,395
49	Obligations Under Capital Leases-Current (243)		555,099,542	1,682,542
50	Derivative Instrument Liabilities (244)		146,893,267	109,769,265
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		124,040,367	88,211,315
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)		10,151,811,576	7,137,187,085
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		355,228,141	359,612,163
57	Accumulated Deferred Investment Tax Credits (255)	266-267	102,885,102	108,383,883
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	242,148,049	227,311,425
60	Other Regulatory Liabilities (254)	278	3,411,145,909	3,496,782,247
61	Unamortized Gain on Reaquired Debt (257)		572,251	716,895
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	307
63	Accum. Deferred Income Taxes-Other Property (282)		8,462,844,659	7,973,787,674
64	Accum. Deferred Income Taxes-Other (283)		1,650,035,294	617,116,725
65	Total Deferred Credits (lines 56 through 64)		14,224,859,405	12,783,711,319
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		86,761,383,154	75,407,879,253

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	18,842,698,287	17,337,575,325		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	21,770,132,822	21,090,929,970		
5	Maintenance Expenses (402)	320-323	2,572,214,173	1,698,634,311		
6	Depreciation Expense (403)	336-337	2,915,778,086	2,708,898,400		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	312,345,977	323,697,675		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		2,113,770	2,113,770		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,613			
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	676,420,547	632,365,632		
15	Income Taxes - Federal (409.1)	262-263	457,455	4,236,134		
16	- Other (409.1)	262-263	168,031,963	13,470,011		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	367,396,283	-864,342,003		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	3,619,594,973	2,478,874,964		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		9,459,742	580,002		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		25,155,838,974	23,130,548,934		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		-6,313,140,687	-5,792,973,609		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
14,242,164,773	13,086,062,407	4,600,533,514	4,251,512,918			2
						3
19,399,846,326	18,919,388,088	2,370,286,496	2,171,541,882			4
1,839,076,052	1,071,056,781	733,138,121	627,577,530			5
2,237,751,122	2,121,424,880	678,026,964	587,473,520			6
						7
218,499,956	225,407,275	93,846,021	98,290,400			8
						9
2,113,770	2,113,770					10
						11
2,613						12
						13
498,485,612	475,321,400	177,934,935	157,044,232			14
-20,429,813	4,236,133	20,887,268	1			15
85,600,295	112,005,442	82,431,668	-98,535,431			16
573,464,127	-738,531,553	-206,067,844	-125,810,450			17
3,728,166,990	2,388,974,856	-108,572,017	89,900,108			18
						19
6,641,455	580,002	2,818,287				20
						21
						22
						23
						24
21,099,601,615	19,802,867,358	4,056,237,359	3,327,681,576			25
-6,857,436,842	-6,716,804,951	544,296,155	923,831,342			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)		-6,313,140,687	-5,792,973,609		
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	-91,657	42,609		
37	Interest and Dividend Income (419)		131,791,178	74,371,716		
38	Allowance for Other Funds Used During Construction (419.1)		79,271,096	129,009,681		
39	Miscellaneous Nonoperating Income (421)		14,613,757	3,071,748		
40	Gain on Disposition of Property (421.1)		4,832,442	315,099		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		230,416,816	206,810,853		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		9,792,051	12,499,780		
46	Life Insurance (426.2)					
47	Penalties (426.3)		49,111,094	5,324,520		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		7,827,488	13,096,115		
49	Other Deductions (426.5)		788,346,091	255,846,898		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		855,076,724	286,767,313		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263		486,744		
53	Income Taxes-Federal (409.2)	262-263	5,078,589	8,062,576		
54	Income Taxes-Other (409.2)	262-263	-80,871,606	-29,809,600		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	6,976,547	33,169,360		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	247,415,278	-25,839,617		
57	Investment Tax Credit Adj.-Net (411.5)		-5,498,780	-5,649,907		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-321,730,528	32,098,790		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-302,929,380	-112,055,250		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		677,880,030	791,084,121		
63	Amort. of Debt Disc. and Expense (428)		126,739,333	29,043,258		
64	Amortization of Loss on Reaquired Debt (428.1)		16,352,937	19,003,995		
65	(Less) Amort. of Premium on Debt-Credit (429)		743,550	818,824		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		144,644	146,025		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		240,449,603	127,444,511		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		54,836,103	52,532,426		
70	Net Interest Charges (Total of lines 62 thru 69)		1,005,697,606	913,078,610		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-7,621,767,673	-6,818,107,469		
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)		-7,621,767,673	-6,818,107,469		

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

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

	2019		2018	
	Revenues	Expenses	Revenues	Expenses
Electric	48,794,887	76,101,792	46,634,494	81,028,298
Gas	216,890,392	189,583,487	208,166,556	173,772,752
Total	265,685,279	265,685,279	254,801,050	254,801,050

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

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

	Current QTR		Prior QTR	
	Revenues	Expenses	Revenues	Expenses
Electric	12,693,015	20,271,180	12,143,310	20,990,921
Gas	68,517,873	60,939,708	53,242,139	44,394,528
Total	81,210,888	81,210,888	65,385,449	65,385,449

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

See footnote in row 2, column D

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

See footnote in row 2, column E

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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		2,598,414,708	9,450,613,073
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Reclassify stranded tax effects			2,079,484
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			2,079,484
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		-7,621,676,016	(6,818,150,078)
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reserves for excess earnings on FERC hydroelectric			
19	project licenses pursuant to Federal Power Act Section 10 (d)	215		(23,656,015)
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			(23,656,015)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26	Accrued Preferred Dividends Requirement			(13,916,318)
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			(13,916,318)
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,766,985	1,444,562
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		-5,021,494,323	2,598,414,708
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40	Reserves for excess earnings on FERC hydroelectric			23,656,015

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)			
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			23,656,015
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		286,020,935	262,364,920
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		286,020,935	286,020,935
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		-4,735,473,388	2,884,435,643
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-58,010,567	(56,608,615)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-91,657	42,610
51	(Less) Dividends Received (Debit)			
52	Other: Stanpac and PEFCO earnings reflected in M&O accounts		-1,766,986	(1,444,562)
53	Balance-End of Year (Total lines 49 thru 52)		-59,869,210	(58,010,567)

Schedule Page: 118 Line No.: 26 Column: c

There were no preferred dividends declared for the periods ended December 31, 2018 and 2019. However, since preferred stocks are cumulative, preferred dividend accruals were erroneously recorded for the period ended December 31, 2018. These accruals were discontinued for 2019 and will not be recorded until the Board of Directors approves the issuance of preferred stock dividends.

Schedule Page: 118 Line No.: 26 Column: d

There were no preferred dividends declared for the period ended December 31, 2018. However, since preferred stocks are cumulative, preferred dividend accruals were recorded. The liability is shown in Line 44, Dividends Declared, on page 112 of the balance sheet. The following is the detail of accrued dividends on First Preferred Stocks for the period ended December 31, 2018:

Annual
No. of Dividends Total

Class of Stock	Shares	Per Share	Accrued
6.00% Cumulative, Non-Redeemable	4,211,662	$1.500	$ 6,317,492
5.50% Cumulative, Non-Redeemable	1,173,163	1.375	1,613,099
5.00% Cumulative, Non-Redeemable	400,000	1.250	500,000
5.00% Cumulative, Redeemable	1,778,172	1.250	2,222,715
5.00% Cumulative, Redeemable-Series A	934,322	1.250	1,167,903
4.80% Cumulative, Redeemable	793,031	1.200	951,637
4.50% Cumulative, Redeemable	611,142	1.125	687,535
4.36% Cumulative, Redeemable	418,291	1.090	455,937
		Total	$13,916,318

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	-7,621,767,673	-6,818,107,469
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	3,230,237,833	3,034,709,845
5	Disallowed Capital Expenditures	580,881,000	-44,798,404
6	Amortization of Unamortized Loss or Gain on Reacquired Debt	16,208,293	18,857,970
7	Amortization of Expenses, Discount and Premium - Long Term Debt	19,417,546	19,699,655
8	Deferred Income Taxes (Net)	-2,945,141,198	-2,538,903,619
9	Investment Tax Credit Adjustment (Net)	-5,498,780	-5,649,907
10	Net (Increase) Decrease in Receivables	-102,302,285	-1,853,762,002
11	Net (Increase) Decrease in Inventory	-79,838,426	-72,749,339
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,737,800,074	348,769,957
14	Net (Increase) Decrease in Other Regulatory Assets	-1,116,620,873	-715,545,561
15	Net Increase (Decrease) in Other Regulatory Liabilities	-302,763,969	-16,151,084
16	(Less) Allowance for Other Funds Used During Construction	79,271,096	129,009,681
17	(Less) Undistributed Earnings from Subsidiary Companies	-1,866,004	-1,401,952
18	Other (provide details in footnote):	11,473,354,719	13,476,022,103
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	4,806,561,169	4,704,784,416
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-6,313,356,194	-6,564,592,641
27	Gross Additions to Nuclear Fuel	-77,742,004	-78,340,868
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-79,271,096	-129,009,681
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-6,311,827,102	-6,513,923,828
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	11,111,891	22,233,335
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,740,858	-1,611,620
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
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	03/25/2020	End of 2019/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			
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	956,151,549	1,411,689,770
55	Purchases of nuclear decommissioning trust investments and other	-1,032,116,370	-1,484,791,279
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-6,378,420,890	-6,566,403,622
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,753,430,038	792,991,500
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		2,334,796,430
67	Other (provide details in footnote):		
68	Equity contribution from PG&E Corporation		45,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,753,430,038	3,172,787,930
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-350,000,000	-445,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Customer Advances for Construction	52,905,338	4,227,505
78	Net Decrease in Short-Term Debt (c)		
79	Other	-56,559,554	-21,850,462
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	1,399,775,822	2,710,164,973
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-172,083,899	848,545,767
87			
88	Cash and Cash Equivalents at Beginning of Period	1,298,361,425	449,815,658
89			
90	Cash and Cash Equivalents at End of period	1,126,277,526	1,298,361,425

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

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

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

This consists of the following:

	2019	2018
Reorganization items, net	$ 97,219,505	$ -
(Increase) Decrease in Other Working Capital	(116,452,698)	(438,463,686)
Increase (Decrease) - Other Noncurrent Liabilities*	11,382,266,594	13,777,892,530
Others		
Nuclear Fuel Lease Amortization	112,531,507	125,886,537
Payment on capital lease obligation	(1,682,542)	(1,921,000)
Collateral Adjustment	6,681,592	12,592,010
Bad Debt Expense	45,946,087	35,471,842
Tax benefit on stock option exercises (shortfall)	(17,193,126)	(11,642,424)
Other-net	(35,962,200)	(23,793,706)
Total	$ 11,473,354,719	$ 13,476,022,103

*In 2019, this primarily consists of a $11.4 billion increase to the "Accumulated Provision" balances (accounts 228.2, 228.3, 228.4 and 229) corresponding to the amount charged related to the 2015 Butte fire, the 2017 Northern California wildfires and the 2018 Camp fire. In 2018, this primarily consists of a $14 billion increase to the "Accumulated Provision" balances (accounts 228.2, 228.3, 228.4 and 229) corresponding to the amount charged for the lower end of the range of the Utility's reasonably estimated losses related to the 2017 Northern California wildfires and the 2018 Camp fire. This increase is partially offset by $109 million of asset retirement obligation work performed.

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

See footnote in column (b), Line 18.

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

This consists of the following:

	2019	2018
Purchases of Nuclear Decommissioning Trust Investments	$ (1,032,127,312)	$ (1,484,791,279)
Decrease in other investments	10,942	-
Total	$ (1,032,116,370)	$ (1,484,791,279)

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

See footnote in column (b), Line 55.

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

This consists of the following:

	2019	2018
Increase (Decrease) in customer deposits	$ (53,417,848)	$ 3,903,352
Debt Issuance Costs - ST Borrowings	-	(25,000)
Employee taxes paid for withheld shares	(6,712,463)	(10,580,685)
Premium paid for early redemption of long-term debt	-	(15,148,129)
Affiliate Letter of Credit draw	3,570,757	-
Total	$ (56,559,554)	$ (21,850,462)

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

See footnote in column (b), Line 79.

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

This consists of the following:

	2019	2018
Cash (131)	$ 294,434,921	$ 71,327,413
Special Deposits (132-134)	7,195,190	6,886,597
Working Funds (135)	147,415	147,415
Temporary Cash Investment (136)	824,500,000	1,220,000,000
Total	$ 1,126,277,526	$ 1,298,361,425

Supplemental disclosure of cash flow information (in millions):

Cash paid for:		
Interest (net of amounts capitalized)	$ (7)	$ (733)
Income taxes paid (refunded), net	-	(59)
Supplemental disclosures of noncash investing and financing activities:		
Capital expenditures financed through accounts payable	826	368
Operating lease liabilities arising from obtaining ROU assets	2,807	-

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

See footnote in column (b), Line 90.

NOTES TO FINANCIAL STATEMENTS

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

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

Introduction:

The notes below are excerpts from PG&E Corporation and the Utility's combined Report on Form 10-K for the year ended December 31, 2019, as filed with the Securities and Exchange Commission ("SEC") on February 18, 2020. The following disclosures contain information in accordance with SEC reporting requirements. As such, due to the differences between FERC and SEC reporting requirements, certain amounts disclosed in the following notes may not agree to balances in the FERC financial statements.

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The primary differences from the Utility's GAAP basis financial statements as presented in the Form 1 are that (1) subsidiaries are not consolidated and are shown under the equity method of accounting, (2) deferred income tax assets and liabilities are not offset against each other but are shown as separate items on the balance sheet, are long-term, and exclude the impact of uncertain temporary tax positions, (3) cost of removal is reported in accumulated depreciation for FERC reporting purposes (GAAP requires that cost of removal be classified as a regulatory liability), (4) there is no current liability classification of the current portion of long-term debt for FERC reporting, (5) there is no reclassification of balancing accounts from current assets to current liabilities for FERC reporting, (6) interdepartmental revenues and expenses between electric and gas operations of the Utility are not eliminated for FERC reporting, (7) penalties and disallowances are reported in other income deductions for FERC reporting, and (8) payments on capital lease obligations are disclosed in operating activities in the statement of cash flows, (9) debt issuance costs are not deducted from the carrying amount of that debt liability for FERC reporting, (10) there is no current liability classification of the current portion of accumulated provision for injuries and damages, in which the estimated losses associated with third-party wildfire claims are recorded, for FERC reporting, (11) FERC reporting does not reclass non-service costs related to pension benefits on the income statement pursuant to ASU 2017-07, (12) there are no separate reporting categories included on the FERC balance sheet for lease assets and liabilities pursuant to ASU 2016-02, (13) there is no reclassification to liabilities subject to compromise for FERC reporting, and (14) there is no reclassification of bankruptcy-related costs to reorganization costs for FERC reporting.

Subsequent Events:

Management has evaluated the impact of events occurring after December 31, 2019 up to February 18, 2020, the date that Pacific Gas and Electric Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 25, 2020. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

On March 16, 2020, the Utility filed an updated Plan of Reorganization (the Plan) to incorporate the terms of prior settlements, among other changes.

On March 20, 2020, the Utility together with PG&E Corporation, its parent company, filed a motion, with the Bankruptcy Court for entry of an order approving a case resolution contingency process to address the circumstance in which the Plan is not confirmed or fails to go effective in accordance with certain required dates (the "Case Resolution Contingency Process"). As further described in the Motion, the Case Resolution Contingency Process contemplates a process for the sale of PG&E Corporation or the Utility in the event that the Plan is not confirmed or fails to go effective in accordance with certain required dates. In addition, the motion sets forth certain other commitments by the Debtors in connection with the confirmation process and implementation of the Plan, including among other things, limitations on the ability of PG&E Corporation to pay dividends; commitments by the Utility with respect to cost recovery of amounts paid in respect of "Fire Claims" under the Plan; the terms of a purchase option in favor of the state of California (which would be exercisable only in limited circumstances); and commitments with respect to the Utility's utilization of wildfire-related net operating losses. Also on March 20, 2020, California Governor filed a responsive pleading in the Bankruptcy Court stating that, assuming the Bankruptcy Court grants the Motion and the California Public Utilities Commission ("CPUC") approves the Plan with the governance, financial and operational provisions submitted to the CPUC by the Utility or otherwise agreed by the Utility, with any modifications the CPUC believes appropriate or necessary, the Plan "will, in the Governor's judgment, be compliant with AB 1054."

On March 17, 2020, the Utility entered into a Plea Agreement and Settlement (the "Agreement") with the People of the State of California, by and through the Butte County District Attorney's office to resolve the criminal prosecution of the Utility in connection with the 2018 Camp fire.

Pursuant to the Agreement, the Utility will be sentenced to pay the maximum total fine and penalty of approximately $3.5 million. The Utility has also agreed to pay $500,000 to the Butte County District Attorney Environmental and Consumer Protection Fund to reimburse costs spent on the investigation of the 2018 Camp fire. Simultaneous with entry into the Agreement, but separate from such Agreement, the Utility has committed to spend up to $15 million over five years to provide water to Butte County residents impacted by damage to the Utility's Miocene Canal caused by the 2018 Camp fire.

On February 27, 2020, the assigned administrative law judge issued a Presiding Officer's Decision in the CPUC's Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire. The decision approves an earlier settlement among the Utility and certain the parties with the following modifications: (i) imposes $198 million in additional disallowances from the Utility's Fire Risk Mitigation Memorandum Account or the Wildfire Mitigation Plan Memorandum Account over a 4-year period, bringing the total amount of disallowances to $1.823 billion (from $1.625 billion in the proposed settlement), (ii) requires the Utility to spend an additional $64 million in shareholder funds on system enhancement initiatives and certain corrective actions, bringing the total in shareholder spend to $114 million (from $50 million in the proposed settlement), (iii) requires the Utility to pay a $200 million fine to the General Fund "out of funds that would not otherwise be available to satisfy the claims of the wildfire victims" and (iv) requires that any tax savings associated with shareholder payments under the settlement be "returned to the benefit of ratepayers." On March 18, 2020, the Utility filed an appeal on the Presiding Officer's Decision. Parties' responses are currently due on April 3, 2020. However, Parties have until March 30, 2020 to file their own appeal of the Presiding Officer's Decision and, if another party appeals, responses to the Utility's appeal and any other appeal(s) will be due 15 days after the last appeal.

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 $30,056,380 at December 31, 2019, 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 $142,788 for the year ended December 31, 2019, all of which is recorded in account 555.1 in accordance with FERC Order No. 784.

Operation and Maintenance Expense Accounts

Energy storage-related operating expenses totaled $0 for the year ended December 31, 2019, of which $0 is recorded in account 582 and $0 is recorded in account 588. Amounts associated with distribution functional use would have been recorded in account 584.1 and amounts associated with production functional use would have been recorded in account 548.1, in accordance with FERC Order No. 784. Please see table below.

Energy storage-related maintenance expenses totaled $614,883 for the year ended December 31, 2019, of which $0 is recorded in account 570 and $614,883 is recorded in account 592. Amounts associated with distribution functional use would have been recorded in account 592.2 and amounts associated with production functional use would have been recorded in account 553.1, in accordance with FERC Order No. 784. Please see table below.

Other Expense Accounts

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

December 31, 2019.

Energy storage-related payroll tax expenses are recorded in account 408.1 in the amount of $0 for the year ended December 31, 2019.

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	$9,199,887	$0	$263,262	$0	$142,788	$0
2	Hitachi	Distribution	San Jose, CA	$20,856,493	$0	$335,556	$0	$0	$0
3	Browns Valley	Distribution	Marysville, CA	$0	$0	$16,065	$0	$0	$0
Totals				**$30,056,380**	**$0**	**$614,883**	**$0**	**$142,788**	**$0**

Accumulated Deferred Income Taxes:

The following table summarizes the amount of excess deferred income taxes for years ended 2019 and 2018 as a result of the Tax Cuts and Job Cut Act. Excess deferred income taxes have been amortized in Accounts 401.1 and 411.1.

in millions

Jurisdiction	12/31/2019	12/31/2018	Amortization Period
FERC			
Protected	$468	$479	Regulated book life of the underlying plant - 15 to 75 years
Unprotected	114	128	Subject to approval
FERC total	$582	$607	
CPUC			
Protected	$2,796	$2,905	Regulated book life of the underlying plant - 5 to 75 years
Unprotected	(664)	(719)	Subject to approval
CPUC total	$2,132	$2,186	
Total	$2,714	$2,793	

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

Organization and Basis of Presentation

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

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

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

Chapter 11 Filing and Going Concern

The accompanying Consolidated Financial Statements have been prepared on a going concern basis, which contemplates the continuity of operations, the realization of assets and the satisfaction of liabilities in the normal course of business. However, as a result of the challenges that are further described below, such realization of assets and satisfaction of liabilities are subject to uncertainty. PG&E Corporation and the Utility suffered material losses as a result of the 2017 Northern California wildfires and the 2018 Camp fire, which contributed to the decision to file for Chapter 11 protection. See Note 14 below. Uncertainty regarding these matters raises substantial doubt about PG&E Corporation's and the Utility's abilities to continue as going concerns. PG&E Corporation and the Utility have determined that commencing reorganization cases under Chapter 11 was necessary to restore PG&E Corporation's and the Utility's financial stability to fund ongoing operations and provide safe service to customers. However, there can be no assurance that such proceedings will restore PG&E Corporation's and the Utility's financial stability. On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. The Consolidated Financial Statements do not include any adjustments that might be necessary should PG&E Corporation and the Utility be unable to continue as going concerns.

Pursuant to sections 1107(a) and 1108 of the Bankruptcy Code, PG&E Corporation and the Utility retain control of their assets and are authorized to operate their business as debtors-in-possession while being subject to the jurisdiction of the Bankruptcy Court. While operating as debtors-in-possession under Chapter 11, PG&E Corporation and the Utility may sell or otherwise dispose of or liquidate assets or settle liabilities, subject to the approval of the Bankruptcy Court or as otherwise permitted in the ordinary course of business and subject to restrictions in PG&E Corporation's and the Utility's DIP Credit Agreement (see Note 5 below) and applicable orders of the Bankruptcy Court, for amounts other than those reflected in the accompanying Consolidated Financial Statements. Any such actions occurring during the Chapter 11 Cases authorized by the Bankruptcy Court could materially impact the amounts and classifications of assets and liabilities reported in PG&E Corporation's and the Utility's Consolidated Financial Statements. (For more information regarding the Chapter 11 Cases, see Note 2 below.)

NOTE 2: BANKRUPTCY FILING

Chapter 11 Proceedings

On January 29, 2019, PG&E Corporation and the Utility commenced the Chapter 11 Cases with the Bankruptcy Court. PG&E Corporation and the Utility continue to operate their business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

Under the Bankruptcy Code, third-party actions to collect pre-petition indebtedness owed by PG&E Corporation or the Utility, as well as most litigation pending against PG&E Corporation and the Utility (including the third-party matters described in Note 14 below) as of the Petition Date, are subject to an automatic stay. Absent an order of the Bankruptcy Court providing otherwise, substantially all pre-petition liabilities will be resolved under a Chapter 11 plan of reorganization to be voted upon by impaired creditors and interest holders, and approved by the Bankruptcy Court. However, under the Bankruptcy Code, regulatory or criminal proceedings generally are not subject to an automatic stay, and these proceedings have been continuing during the pendency of the Chapter 11 Cases.

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

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

Significant Bankruptcy Court Actions

First Day Motions

On January 31, 2019, the Bankruptcy Court approved, on an interim basis, certain motions (the “First Day Motions”) authorizing, but not directing, PG&E Corporation and the Utility to, among other things, (a) secure $5.5 billion of debtor-in-possession financing; (b) continue to use PG&E Corporation’s and the Utility’s cash management system; and (c) pay certain pre-petition claims relating to (i) certain safety, reliability, outage, and nuclear facility suppliers; (ii) shippers, warehousemen, and other lien claimants; (iii) taxes; (iv) employee wages, salaries, and other compensation and benefits; and (v) customer programs, including public purpose programs. The First Day Motions were subsequently approved by the Bankruptcy Court on a final basis at hearings on February 27, 2019, March 12, 2019, March 13, 2019, and March 27, 2019.

Bar Date

On July 1, 2019, the Bankruptcy Court entered an order approving a deadline of October 21, 2019, at 5:00 p.m. (Pacific Time) (the “Bar Date”) for filing claims against PG&E Corporation and the Utility relating to the period prior to the Petition Date. The Bar Date is subject to certain exceptions, including for claims arising under section 503(b)(9) of the Bankruptcy Code, the bar date for which occurred on April 22, 2019. The Bankruptcy Court also approved PG&E Corporation’s and the Utility’s plan to provide notice of the Bar Date to parties in interest, including potential wildfire-related claimants and other potential creditors. On November 11, 2019, the Bankruptcy Court entered an order approving a stipulation between PG&E Corporation and the Utility and the TCC to extend the Bar Date for unfiled, non-governmental fire claimants to December 31, 2019, at 5:00 p.m. (Pacific Time).

Other Significant Actions Related to the Chapter 11 Cases

Other significant actions and developments related to the Chapter 11 Cases, including the Tubbs Lift Stay Decision, the Tubbs Trial and the Estimation Proceeding are described in Note 14 (including under the headings "Proceeding in San Francisco County Superior Court for Certain Tubbs Fire-Related Claims" and "Wildfire Claims Estimation Proceeding in the U.S. District Court for the Northern District of California").

On October 28, 2019, the Bankruptcy Court issued an order directing the principal parties in the Chapter 11 Cases to participate in mediation.

Plan of Reorganization, RSAs, Equity Backstop Commitments and Debt Commitment Letters

On September 9, 2019, PG&E Corporation and the Utility filed with the Bankruptcy Court their Joint Chapter 11 Plan of Reorganization for the resolution of the outstanding pre-petition claims against and interests in PG&E Corporation and the Utility, which was thereafter amended on September 23, 2019 and November 4, 2019. On January 31, 2020, PG&E Corporation and the Utility, certain funds and accounts managed or advised by Abrams Capital Management, LP ("Abrams"), and certain funds and accounts managed or advised by Knighthead Capital Management, LLC ("Knighthead" and, together with Abrams, the "Shareholder Proponents") filed the Debtors' and Shareholder Proponents' Joint Chapter 11 Plan of Reorganization dated January 31, 2020 with the Bankruptcy Court (as may be amended, modified or supplemented from time to time, the "Proposed Plan").

On September 22, 2019, PG&E Corporation and the Utility entered into a Restructuring Support Agreement with certain holders of insurance subrogation claims (collectively, the "Consenting Subrogation Creditors") which agreement was amended and restated on November 1, 2019 and subsequently amended further during November and December 2019 (as amended, the "Subrogation RSA"). The Subrogation RSA provides for an aggregate amount of $11.0 billion (the "Allowed Subrogation Claim Amount") to be paid by PG&E Corporation and the Utility pursuant to the Proposed Plan in order to settle all insurance subrogation claims (the "Subrogation Claims") relating to the 2017 Northern California wildfires and the 2018 Camp fire (the "Subrogation Claims Settlement"), upon the terms and conditions set forth in the Subrogation RSA. Under the Subrogation RSA, PG&E Corporation and the Utility also have agreed to reimburse the holders of Subrogation Claims for professional fees of up to $55 million, upon the terms and conditions set forth in the Subrogation RSA. On September 24, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking authority to enter into, and perform under, the Subrogation RSA and approval of the Subrogation Claims Settlement. Hearings on PG&E Corporation's and the Utility's motion to approve the Subrogation RSA were held on October 23, 2019, December 4, 2019 and December 17, 2019. On December 19, 2019, the Bankruptcy Court entered an order granting PG&E Corporation's and the Utility's motion to approve the Subrogation RSA. See "Restructuring Support Agreement with Holders of Subrogation Claims" in Note 14 for further information on the Subrogation RSA.

On December 6, 2019, PG&E Corporation and the Utility entered into a Restructuring Support Agreement, which was subsequently amended on December 16, 2019 (as amended, the "TCC RSA"), with the TCC, the attorneys and other advisors and agents for holders of Fire Victim Claims (as defined below) that are signatories to the TCC RSA (each a "Consenting Fire Claimant Professional"), and the Shareholder Proponents. The TCC RSA provides for, among other things, an aggregate of $13.5 billion in value to be provided by PG&E Corporation and the Utility pursuant to the Proposed Plan in order to settle and discharge all claims against PG&E Corporation and the Utility relating to the 2015 Butte fire, the 2017 Northern California wildfires and the 2018 Camp fire (other than the Subrogation Claims and the Public Entity Wildfire Claims) (the "Fire Victim Claims"), upon the terms and conditions set forth in the TCC RSA and the Proposed Plan. On December 9, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking authority to enter into, and perform under, the TCC RSA. A hearing on PG&E Corporation's and the Utility's motion to approve the TCC RSA was held on December 17, 2019. On December 19, 2019, the Bankruptcy Court entered an order granting PG&E Corporation's and the Utility's motion to approve the TCC RSA. See "Restructuring Support Agreement with the TCC" in Note 14 for further information on the TCC RSA.

Proposed Plan of Reorganization

The Proposed Plan proposes the following:

- compensation of wildfire victims and certain public entities from a trust funded for their benefit in an aggregate value of $13.5 billion in accordance with the terms of the TCC RSA (as further described under the heading “Restructuring Support Agreement with the TCC” in Note 14);
- compensation of insurance subrogation claimants from a trust funded for their benefit in the amount of $11.0 billion in cash in accordance with the terms of the Subrogation Claims Settlement and Subrogation RSA (as further described under the heading “Restructuring Support Agreement with Holders of Subrogation Claims” in Note 14);
- payment of $1.0 billion in cash in full settlement of the claims of the settling public entities relating to the wildfires (as further described under the heading “Plan Support Agreements with Public Entities” in Note 14);
- entitlement for the holders of claims related to the 2016 Ghost Ship fire to pursue their claims after the Effective Date, with any recovery being limited to amounts available under PG&E Corporation’s and the Utility’s insurance policies;
- refinancing of Utility Short-Term Notes, Utility Long-Term Notes and Utility Funded Debt (except Pollution Control Bonds Series 2008F and 2010E, which will be repaid in cash) with the issuance of new notes, reinstatement of Utility Reinstated Notes and reimbursement of the holders of Utility Long-Term Senior Notes for debt placement fees and the members of the Ad Hoc Noteholder Committee for professional fees of up to $99 million (as further described under the heading “Restructuring Support Agreement with the Ad Hoc Noteholder Committee”);
- payment in full of all pre-petition funded debt obligations of PG&E Corporation, all pre-petition trade claims and all pre-petition employee-related unsecured claims;
- assumption of all power purchase agreements and community choice aggregation servicing agreements;
- assumption of all pension obligations, other employee obligations, and collective bargaining agreements with labor;
- future participation in the state wildfire fund established by AB 1054; and
- satisfaction of the requirements of AB 1054.

The Proposed Plan proposes the following key financing sources:

- one or more equity offerings of up to $9.0 billion, in accordance with the Backstop Commitment Letters, although the Backstop Commitment Letters (as described below) permit PG&E Corporation to draw up to $12.0 billion;
- the issuance of $6.75 billion of new equity to the Fire Victim Trust;
- the issuance of $4.75 billion of new PG&E Corporation debt;
- the reinstatement of $9.575 billion of pre-petition debt of the Utility;
- the issuance of $23.775 billion of new Utility debt, consisting of (i) $6.2 billion of New Utility Long-Term Notes to be issued to holders of certain pre-petition senior notes of the Utility pursuant to the Proposed Plan, (ii) $1.75 billion of New Utility Short-Term Notes to be issued to holders of certain pre-petition senior notes of the Utility pursuant to the Proposed Plan, (iii) $3.9 billion of Utility Funded Debt Exchange Notes to be issued to holders of certain pre-petition indebtedness of the Utility pursuant to the Proposed Plan and (iv) $11.925 billion of new debt securities or bank debt of the Utility to be issued to third parties for cash on or prior to the Effective Date (of which $6.0 billion is expected to be repaid with the proceeds of a new securitization transaction after the Effective Date);

- approximately $2.2 billion in proceeds of PG&E Corporation's and the Utility's liability insurance proceeds for wildfire events; and
- cash available to PG&E Corporation or the Utility immediately prior to the Effective Date.

On October 4, 2019, the CPUC issued an OII to consider the ratemaking and other implications of the Proposed Plan.

The Proposed Plan has not been approved and is subject to regulatory review by the CPUC and FERC, as and to the extent required by law, including as potentially causing a change in control under Section 203 of the Federal Power Act. The Proposed Plan may be further amended, modified, or supplemented as necessary or desired by PG&E Corporation and the Utility or as required by the Bankruptcy Court or the CPUC.

Disclosure Statement

On February 7, 2020, pursuant to section 1125 of the Bankruptcy Code, PG&E Corporation and the Utility filed a proposed disclosure statement (the "Proposed Disclosure Statement"), with all schedules and exhibits thereto, for the Proposed Plan. PG&E Corporation and the Utility filed on February 18, 2020, a motion requesting that the Court (i) establish Plan solicitation and voting procedures, and (ii) approve the forms of Ballots, Solicitation Packages, and related notices to be sent to the various creditors and interest holders in connection with confirmation of the Plan (the "Solicitation Procedures Motion"). A hearing to consider approval of the Proposed Disclosure Statement and the relief requested in the Solicitation Procedures Motion is scheduled for March 10, 2020.

Restructuring Support Agreement with the Ad Hoc Noteholder Committee

On January 22, 2020, PG&E Corporation and the Utility entered into the Noteholder RSA with those holders of senior unsecured debt of the Utility that are identified as "Consenting Noteholders" below and the Shareholder Proponents. The Noteholder RSA provides for, among other things, (i) the refinancing of the Utility's senior unsecured debt in satisfaction of all claims arising out of the Utility Short-Term Senior Notes, the Utility Long-Term Senior Notes and the Utility Funded Debt, each as defined below, and (ii) the reinstatement of the Utility Reinstated Senior Notes, as defined below (together with the Utility Short-Term Senior Notes and Utility Long-Term Senior Notes, the "Utility Senior Note Claims"), in each case pursuant to the Proposed Plan and upon the terms and conditions set forth in the Noteholder RSA. Under the Noteholder RSA, PG&E Corporation and the Utility have also agreed to reimburse the holders of Utility Long-Term Senior Notes for debt placement fees and the members of the Ad Hoc Noteholder Committee for professional fees of up to $99 million upon the terms and conditions set forth in the Noteholder RSA. The following holders of Utility Senior Notes Claims are party to the Noteholder RSA as "Consenting Noteholders" as of the date hereof: Apollo Global Management LLC, Elliott Management Corporation, Oaktree Capital Management L.P., Farallon Capital Management LLC, Capital Group, Värde Partners Inc., Davidson Kempner Capital Management LP, Canyon Capital Advisors LLC, Third Point LLC, Pacific Investment Management Company LLC, Citadel Advisors LLC and Sculptor Capital Investments, LLC. Any holder of Utility Senior Note Claims or Utility Funded Debt can become a party to the Noteholder RSA by executing the joinder attached to the Noteholder RSA.

The Noteholder RSA provides for the following treatment of Utility Senior Note Claims and Utility Funded Debt which treatment has been incorporated into the Proposed Plan:

- Utility Short-Term Senior Notes: Currently outstanding Utility notes maturing through 2022 in an aggregate principal amount of $1.75 billion (the "Utility Short-Term Senior Notes") will receive new Utility secured notes in the following aggregate principal amounts: $875 million of new Utility 3.45% secured notes due 2025 and $875 million of new Utility 3.75% secured notes due 2028 (together, the "New Utility Short-Term Notes"). The New Utility Short-Term Notes will otherwise have substantially similar terms and conditions as the Utility's 6.05% Senior Notes due March 1, 2034. Additionally, holders of claims arising out of the Utility Short-Term Senior Notes will receive cash in an amount equal to the sum of (1) the amount of pre-petition interest outstanding on the Utility Short-Term Senior Notes calculated using the applicable non-default contract rate and (2) interest calculated using the federal judgment rate on the sum of (A) the applicable principal amount of the Utility Short-Term Senior Notes and (B) the amount in clause (1) for the period commencing on the day after the Petition Date and ending on the Effective Date.

- Utility Long-Term Senior Notes: All long-term Utility notes bearing an interest rate greater than 5% of which there is an aggregate principal amount outstanding of $6.2 billion (the "Utility Long-Term Senior Notes"), will receive new Utility secured notes in the following aggregate principal amounts: $3.1 billion of new Utility 4.55% secured notes due 2030 and $3.1 billion of new Utility 4.95% secured notes due 2050 (together, the "New Utility Long-Term Notes"). The New Utility Long-Term Notes will otherwise have substantially similar terms and conditions as the Utility's 3.95% Senior Notes due December 1, 2047. Additionally, holders of claims arising out of the Utility Long-Term Senior Notes will receive cash in an amount equal to the sum of (1) the amount of pre-petition interest outstanding on the Utility Long-Term Senior Notes calculated using the applicable non-default contract rate and (2) interest calculated using the federal judgment rate on the sum of (A) the applicable principal amount of the Utility Long-Term Senior Notes and (B) the amount in clause (1) for the period commencing on the Petition Date and ending on the Effective Date.

- Utility Reinstated Senior Notes: The remaining outstanding $9.575 billion aggregate principal amount of Utility notes (the "Utility Reinstated Senior Notes") will be reinstated on their contractual terms, including being secured equally and ratably with the New Utility Short-Term Notes and the New Utility Long-Term Notes.

- Utility Funded Debt: Holders of the Utility's pre-petition credit facilities and Pollution Control bonds (collectively, the "Utility Funded Debt") will receive new Utility secured notes in the following aggregate principal amounts: $1.949 billion in new Utility 3.15% senior secured notes due 2025, and $1.949 billion in new Utility 4.50% senior secured notes due 2040 (the "New Utility Funded Debt Exchange Notes"). The New Utility Funded Debt Exchange Notes will otherwise have substantially similar terms and conditions as the Utility's 6.05% Senior Notes due March 1, 2034. Additionally, holders of claims arising out of the Utility Funded Debt will receive cash in an amount equal to the sum of (1) the amount of pre-petition interest outstanding on the Utility Funded Debt calculated using the applicable non-default contract rate, (2) fees and charges and other obligations owed as of the Petition Date in respect of the Utility Funded Debt, (3) reasonable attorney's fees and expenses of counsel, subject a maximum of $6 million and (4) interest calculated using the federal judgment rate on the sum of (A) the applicable principal amount of the Utility Funded Debt and (B) the amount in clauses (1) and (2) for the period commencing on the Petition Date and ending on the Effective Date.

The Noteholder RSA further provides that PG&E Corporation and the Utility must use their best efforts to cause various parties to PG&E Corporation and the Utility's equity backstop commitment letters to transfer up to $2.0 billion of equity backstop commitments to certain of the Consenting Noteholders.

Under the Noteholder RSA, each Consenting Noteholder must, among other things, (i) withdraw any participation in and support for the Ad Hoc Noteholder Plan, including by taking certain actions to defer further action on the make-whole and post-petition interest issues, (ii) immediately direct counsel for the Ad Hoc Noteholder Committee to suspend its motion to reconsider the Bankruptcy Court order approving the Subrogation RSA and the TCC RSA and oppose any and all efforts and procedures to terminate, vacate or modify the TCC RSA or the Subrogation RSA, (iii) immediately withdraw all discovery issued in connection with PG&E Corporation and the Utility's motion to approve their exit financing and file a statement in support of such motion, (iv) immediately withdraw all filings submitted in any proceeding before the CPUC involving PG&E Corporation and the Utility and cease participation in any proceeding before the CPUC involving PG&E Corporation and the Utility, and (v) vote to accept the Proposed Plan. Further, each Consenting Noteholder and each of its affiliates shall not, among other things, object to, delay, impede or take any other action to interfere with the approval of PG&E Corporation and the Utility's disclosure statement or the solicitation of votes to accept, acceptance, confirmation, or implementation of the Proposed Plan. Each Consenting Noteholder further agreed, subject to certain exceptions, not to transfer any of its claims against PG&E Corporation and the Utility, unless the transferee either is a Consenting Noteholder, or before such transfer agrees in writing to become a Consenting Noteholder and to be bound by all the terms of the Noteholder RSA.

The Noteholder RSA will automatically terminate if the Effective Date of the Proposed Plan does not occur on or prior to September 30, 2020 or December 31, 2020 if such later outside date is approved by the Bankruptcy Court.

The Noteholder RSA may be terminated by a majority of the Consenting Noteholders under certain circumstances, including, among others, if (i) the treatment of the Utility Senior Note Claims or claims arising from Utility Funded Debt in the Proposed Plan are, or are modified to be, inconsistent with the Noteholder RSA, (ii) an order confirming the Proposed Plan is not entered on or before June 30, 2020, (iii) PG&E Corporation and the Utility fail to achieve an investment grade rating on the new senior secured notes from at least one credit rating agency on the Effective Date, (iv) PG&E Corporation and the Utility's equity backstop commitment letters representing a majority of the equity backstop commitments are terminated or (v) PG&E Corporation and the Utility or the Shareholder Proponents breach certain provisions of the Noteholder RSA. The Noteholder RSA may be terminated by PG&E Corporation and the Utility or the Shareholder Proponents under certain circumstances, including, among others, if the Consenting Noteholders breach certain provisions of the Noteholder RSA.

PG&E Corporation and the Utility and the Shareholder Proponents have separately agreed with certain of the Consenting Noteholders that, among other things, these Consenting Noteholders and certain of their representatives will not have any communications regarding the Proposed Plan, any changes to the Proposed Plan, or any alternative plan of reorganization or other strategic transaction related to PG&E Corporation and the Utility, with certain external stakeholders of PG&E Corporation and the Utility, including certain claimholders, government officials and certain of their representatives. This agreement will be filed under seal with the Bankruptcy Court.

Equity Backstop Commitments

As of December 31, 2019, PG&E Corporation has entered into Chapter 11 Plan Backstop Commitment Letters (collectively, the "Backstop Commitment Letters") with investors (collectively, the "Backstop Parties"), pursuant to which the Backstop Parties severally agreed to fund up to $12.0 billion of proceeds to finance the Proposed Plan through the purchase of PG&E Corporation common stock, subject to the terms and conditions set forth in such Backstop Commitment Letters (the "Backstop Commitments"). The price at which any such new shares would be issued to the Backstop Parties would be equal to (a) 10 (subject to adjustment as provided in the Backstop Commitment Letters), times (b) PG&E Corporation's consolidated Normalized Estimated Net Income (as defined in the Backstop Commitment Letters) for the estimated year 2021, divided by (c) the number of fully diluted shares of PG&E Corporation that will be outstanding on the effective date of the Proposed Plan (the "Effective Date") (assuming that all equity is raised by funding the Backstop Commitments).

The Backstop Commitment Letters provide that, under certain circumstances, PG&E Corporation and the Utility will be permitted to issue new shares of common stock of PG&E Corporation for up to $12.0 billion of proceeds to finance the transactions contemplated by the Proposed Plan through one or more equity offerings that, under certain circumstances, must include a rights offering (the "Rights Offering"). The structure, terms and conditions of any such equity offering (including a Rights Offering) are expected to be determined by PG&E Corporation and the Utility at a later time in the Chapter 11 process, subject to the terms and conditions of the Backstop Commitment Letters. This may include terms and conditions that are designed to preserve the ability of PG&E Corporation or the Utility to utilize their net operating loss carryforwards. There can be no assurance that any such equity offering would be successful. In the event that such equity offerings (together with additional permitted capital sources) do not raise at least $12.0 billion of proceeds in the aggregate or if PG&E Corporation and the Utility do not otherwise consummate such offerings, then PG&E Corporation and the Utility may draw on the Backstop Commitments for equity funding to finance the transactions contemplated by the Proposed Plan, subject to the satisfaction or waiver by the Backstop Parties of the conditions set forth therein. Although the Backstop Commitment Letters permit PG&E Corporation to draw up to $12.0 billion in equity, the Proposed Plan contemplates an equity raise of only $9.0 billion, which equity will be raised in accordance with the terms of the Backstop Commitment Letters.

Under the Backstop Commitment Letters, PG&E Corporation agrees that if the Backstop Commitments are drawn, and PG&E Corporation does not expect to conduct a third-party transaction based upon or related to the utilization or monetization of any net operating losses or tax deductions resulting from the payment of pre-petition wildfire-related claims (a "Tax Benefits Monetization Transaction") on the Effective Date, no later than five business days prior to the Effective Date, PG&E Corporation and the Utility must form a trust which would provide for periodic distributions of cash to the Backstop Parties in amounts equal to (i) all tax benefits arising from the payment of wildfire-related claims in excess of (ii) the first $1.35 billion of tax benefits, starting with fiscal year 2020. PG&E Corporation intends to explore a Tax Benefits Monetization Transaction.

The Backstop Parties' funding obligations under the Backstop Commitment Letters are subject to numerous conditions, including, among others, that (a) the Backstop Commitment Letters have been approved by the Bankruptcy Court, (b) the conditions precedent to the Effective Date set forth in the Proposed Plan have been satisfied or waived in accordance with the Proposed Plan, (c) the Bankruptcy Court has entered an order confirming the Proposed Plan and approving the transactions contemplated thereunder, which shall confirm the Proposed Plan with such amendments, modifications, changes and consents as are approved by holders of a majority of the aggregate Backstop Commitments (the "Confirmation Order"), (d) PG&E Corporation's and the Utility's weighted average earning rate base for 2021 is no less than 95% of $48 billion, and (e) there has been no event, occurrence or other circumstance that would have or would reasonably be expected to have a material adverse effect on the business of PG&E Corporation and the Utility or their ability to consummate the transactions contemplated by the Backstop Commitment Letters and the Proposed Plan. The Backstop Parties have consented to move the deadline for Bankruptcy Court approval of the Backstop Commitment Letters to February 28, 2020.

In addition, the Backstop Parties have certain termination rights under the Backstop Commitment Letters, including, among others, if (a) the Proposed Plan (including as may be amended, modified or otherwise changed) does not include Abrams and Knighthead as plan proponents and is not in a form acceptable to each of Abrams and Knighthead, (b) the Bankruptcy Court has not entered an order approving the Backstop Commitment Letters by February 28, 2020, (c) PG&E Corporation's and the Utility's aggregate liability with respect to pre-petition wildfire-related claims exceeds $25.5 billion, (d) the Proposed Plan is amended without the consent of the holders of a majority of the aggregate Backstop Commitments, (e) the Confirmation Order has not been entered by the Bankruptcy Court by June 30, 2020, (f) the Effective Date has not occurred within 60 days of entry of the Confirmation Order, (g) a material adverse effect (as described above) occurs, (h) wildfires occur in the Utility's service area in 2019 that damage or destroy in excess of 500 dwellings or commercial structures in the aggregate, (i) the CPUC fails to issue all necessary approvals, authorizations and final orders to implement the Proposed Plan prior to June 30, 2020, including approvals related to the Utility's capital structure and authorized rate of return and the resolution of the CPUC's claims against the Utility for fines or penalties, all of which must be satisfactory to the holders of a majority of the aggregate Backstop Commitments, (j) the amount of asserted administrative expense claims or the amount of administrative expense claims PG&E Corporation and the Utility have reserved for and/or paid in the aggregate exceeds $250 million, in each case excluding administrative expense claims that are ordinary course, professional fee claims, claims that are disallowed in the Chapter 11 Cases and the portion of an administrative expense claim that is covered by insurance, (k) one or more wildfires occur in the Utility's service area on or after January 1, 2020 that damage or destroy at least 500 dwellings or commercial structures in the aggregate at a time when the portion of the Utility's system at the location of such wildfire was not successfully de-energized, (l) as of the Effective Date, the Utility has not elected and received Bankruptcy Court approval, or satisfied the other required conditions, to participate in the statewide wildfire fund established by AB 1054, (m) at any time the Bankruptcy Court determines that PG&E Corporation and the Utility are insolvent, (n) PG&E Corporation and the Utility enter into any Tax Benefit Monetization Transaction and the net cash proceeds thereof are less than $3.0 billion, excluding the $1.35 billion of tax benefits to be utilized in the Proposed Plan, and (o) the Proposed Plan or any supplements to or other documents in connection with the Proposed Plan has been amended, modified or changed, without the consent of the holders of at least 66 2/3% of the aggregate Backstop Commitments, to include a process for transferring the license and operating assets of the Utility to the State of California or a third party (a "Transfer") or PG&E Corporation and the Utility effect a Transfer other than pursuant to the Proposed Plan. There can be no assurance that the conditions precedent set forth in the Backstop Commitment Letters will be satisfied or waived, nor that events or circumstances will not occur that give rise to termination rights of the Backstop Parties.

The commitment premium for the Backstop Commitments is 6.364% of the amount of the Backstop Commitments. Such commitment premium will be earned in full upon Bankruptcy Court approval of the Backstop Commitment Letters, subject to clawback under certain circumstances set forth in the Backstop Commitment Letters. Subject to limited exceptions, all commitment premiums are payable in shares of common stock of PG&E Corporation to be issued on the Effective Date, and the number of such shares to be paid as commitment premiums will be calculated using the backstop price described above. In the event that a plan of reorganization for PG&E Corporation that is not the Proposed Plan is confirmed by the Bankruptcy Court, then the backstop commitment premium will be payable in cash if elected by the applicable Backstop Party. Under the Backstop Commitment Letters, PG&E Corporation and the Utility have also agreed to reimburse the Backstop Parties for reasonable professional fees and expenses of up to $17 million in the aggregate for the legal advisor and $19 million in the aggregate for the financial advisor, upon the terms and conditions set forth in the Backstop Commitment Letters.

Debt Commitment Letters

On October 11, 2019, PG&E Corporation and the Utility entered into debt commitment letters, which were subsequently amended on November 18, 2019, December 20, 2019, January 30, 2020, and February 14, 2020 (as amended, the "Debt Commitment Letters") with JPMorgan Chase Bank, N.A., Bank of America, N.A., BofA Securities, Inc., Barclays Bank PLC, Citigroup Global Markets Inc., Goldman Sachs Bank USA, Goldman Sachs Lending Partners LLC and the other lenders that may become parties to the Debt Commitment Letters as additional "Commitment Parties" as provided therein (the foregoing parties, collectively, the "Commitment Parties"), pursuant to which the Commitment Parties committed to provide $10.825 billion in bridge financing in the form of (a) a $5.825 billion senior secured bridge loan facility (the "OpCo Facility") with the Utility or any domestic entity formed to hold all of the assets of the Utility upon emergence from bankruptcy (the Utility or any such entity, the "OpCo Borrower") as borrower thereunder and (b) a $5.00 billion senior unsecured bridge loan facility (together with the OpCo Facility, the "Facilities") with PG&E Corporation or any domestic entity formed to hold all of the assets of PG&E Corporation upon emergence from bankruptcy (the Corporation or any such entity, the "HoldCo Borrower") as borrower thereunder, subject to the terms and conditions set forth therein. The commitments under the Debt Commitment Letters will expire on August 29, 2020, unless terminated earlier pursuant to the termination rights described below.

Borrowings under the OpCo Facility would be senior secured obligations of the OpCo Borrower, secured by substantially all of the assets of the OpCo Borrower. Borrowings under the HoldCo Facility would be senior unsecured obligations of the HoldCo Borrower. The OpCo Borrower's obligations under the OpCo Facility, and the HoldCo Borrower's obligations under the HoldCo Facility, would not be guaranteed by any other entity. The scheduled maturity of each of the Facilities would be 364 days following the date the Facilities are funded. PG&E Corporation and the Utility will pay customary fees and expenses in connection with obtaining the Facilities.

In connection with the anticipated funding for the Proposed Plan and the anticipated amount of debt and equity to be used for funding thereunder, on February 14, 2020, the Debt Commitment Letters were amended to, among other things, (1) adjust the maximum amount of any roll-over, "take-back" or reinstated debt permitted under the Facilities from $30.0 billion to $33.35 billion at the Utility and from $7.0 billion to $5.0 billion at PG&E Corporation and (2) increase the amount of proceeds from the issuance of debt securities or other debt for borrowed money as a condition to funding from $2.0 billion at PG&E Corporation to $6.0 billion at the Utility.

The Commitment Parties' funding obligations under the Debt Commitment Letters are subject to numerous conditions and termination rights, including, among others, certain conditions and termination rights similar to those included in the Backstop Commitment Letters, in addition to conditions that are not in the Backstop Commitment Letters, including (a) the delivery of specified financial information, (b) PG&E Corporation's receipt of at least $9.0 billion of proceeds from the issuance of equity, (c) the execution of definitive documentation for the Facilities and (d) that the Utility shall have received investment grade senior secured debt ratings. In addition, the Debt Commitment Letters are subject to approval by the Bankruptcy Court on or before February 28, 2020, and the Utility's ability to borrow under the OpCo Facility is subject to approval by the CPUC.

In lieu of entering into the Facilities, PG&E Corporation and the Utility intend to obtain permanent financing on or prior to emergence from bankruptcy in the form of bank facilities, debt securities or a combination of the foregoing.

On October 23, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking approval of the Backstop Commitment Letters, the Debt Commitment Letters and certain related matters. The hearing on PG&E Corporation's and the Utility's motion to approve the Backstop Commitment Letters, the Debt Commitment Letters and certain related matters is scheduled for February 26, 2020.

The timing and outcome of the Chapter 11 Cases is uncertain. Although PG&E Corporation, the Utility, the Bankruptcy Court, the CPUC and many other stakeholders have stated that they are working towards confirming a plan of reorganization by June 30, 2020, it is possible that the Chapter 11 process could extend beyond the June 30, 2020 deadline and take a number of years to resolve.

Ad Hoc Noteholder Plan of Reorganization

On October 17, 2019, the TCC and the Ad Hoc Noteholder Committee filed the Ad Hoc Noteholder Plan. On December 19, 2019, pursuant to the TCC RSA (described below), the TCC filed a notice of withdrawal as a plan proponent of the Ad Hoc Noteholder Plan with the Bankruptcy Court. The Ad Hoc Noteholder Plan differed from the Proposed Plan in a number of respects, including, but not limited to, its treatment of equity interests, its treatment of holders of claims in respect of debt of PG&E Corporation and the Utility and its financing sources.

On January 22, 2020, the Ad Hoc Noteholder Committee entered into the Noteholder RSA with PG&E Corporation and the Utility, under which it agreed, upon entry of the order of the Bankruptcy Court approving the Noteholder RSA, to withdraw any participation in and support for the Ad Hoc Noteholder Plan, including by taking certain actions to defer further action on the make-whole and post-petition interest issues. On February 4, 2020, the Noteholder RSA was approved by the Bankruptcy Court, and on February 5, 2020, the Ad Hoc Noteholder Committee withdrew the Ad Hoc Noteholder Plan. It is possible that, if the Noteholder RSA is terminated, the Ad Hoc Noteholder Committee could re-file a competing plan with similar or different terms.

Debtor-In-Possession Financing

See Note 5 for further discussion of the DIP Facilities, which provide up to $5.5 billion in financing.

Financial Reporting in Reorganization

Effective on the Petition Date, PG&E Corporation and the Utility began to apply accounting standards applicable to reorganizations, which are applicable to companies under Chapter 11 bankruptcy protection. These accounting standards require the financial statements for periods subsequent to the Petition Date to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Expenses, realized gains and losses, and provisions for losses that are directly associated with reorganization proceedings must be reported separately as reorganization items, net in the Consolidated Statements of Income. In addition, the balance sheet must distinguish pre-petition LSTC of PG&E Corporation and the Utility from pre-petition liabilities that are not subject to compromise, post-petition liabilities, and liabilities of the subsidiaries of PG&E Corporation that are not debtors in the Chapter 11 Cases in the Consolidated Balance Sheets. LSTC are pre-petition obligations that are not fully secured and have at least a possibility of not being repaid at the full claim amount. Where there is uncertainty about whether a secured claim will be paid or impaired pursuant to the Chapter 11 Cases, PG&E Corporation and the Utility have classified the entire amount of the claim as LSTC.

Furthermore, the realization of assets and the satisfaction of liabilities are subject to uncertainty. While operating as debtors-in-possession, actions to enforce or otherwise effect the payment of certain claims against PG&E Corporation and the Utility in existence before the Petition Date are stayed while PG&E Corporation and the Utility continue business operations as debtors-in-possession. These claims are reflected as LSTC in the Consolidated Balance Sheets at December 31, 2019. Additional claims (which could be LSTC) may arise after the Petition Date resulting from the rejection of executory contracts, including leases, and from the determination by the Bankruptcy Court (or agreement by parties-in-interest) of allowed claims for contingencies and other disputed amounts.

PG&E Corporation's Consolidated Financial Statements are presented on a consolidated basis and include the accounts of PG&E Corporation and the Utility and other subsidiaries of PG&E Corporation and the Utility that individually and in aggregate are immaterial. Such other subsidiaries did not file for bankruptcy.

The Utility's Consolidated Financial Statements are presented on a consolidated basis and include the accounts of the Utility and other subsidiaries of the Utility that individually and in aggregate are immaterial. Such other subsidiaries did not file for bankruptcy.

Liabilities Subject to Compromise

As a result of the commencement of the Chapter 11 Cases, the payment of pre-petition liabilities is subject to compromise or other treatment pursuant to a plan of reorganization. Generally, actions to enforce or otherwise effect payment of pre-petition liabilities are stayed. Although payment of pre-petition claims generally is not permitted, the Bankruptcy Court granted PG&E Corporation and the Utility authority to pay certain pre-petition claims in designated categories and subject to certain terms and conditions. This relief generally was designed to preserve the value of PG&E Corporation's and the Utility's business and assets. As described above, among other things, the Bankruptcy Court authorized, but did not require, PG&E Corporation and the Utility to pay certain pre-petition claims relating to employee wages and benefits, taxes, and amounts owed to certain vendors.

The determination of how liabilities will ultimately be settled or treated cannot be made until the Bankruptcy Court confirms a Chapter 11 plan of reorganization and such plan becomes effective. Accordingly, the ultimate amount of such liabilities is not determinable at this time. GAAP requires pre-petition liabilities that are subject to compromise to be reported at the amounts expected to be allowed by the Bankruptcy Court, even if they may be settled for different amounts. The amounts currently classified as LSTC are preliminary and may be subject to future adjustments depending on Bankruptcy Court actions, further developments with respect to disputed claims, determinations of the secured status of certain claims, the values of any collateral securing such claims, rejection of executory contracts, continued reconciliation or other events.

The following table presents LSTC as reported in the Consolidated Balance Sheets at December 31, 2019:

(in millions)	**Utility**	**PG&E Corporation (1)**	**PG&E Corporation Consolidated**
Financing debt (2)	$ 22,450	$ 666	$ 23,116
Wildfire-related claims (3)	25,548	—	25,548
Trade creditors	1,183	5	1,188
Non-qualified benefit plan	20	137	157
2001 bankruptcy disputed claims (4)	234	—	234
Customer deposits & advances	71	—	71
Other	230	2	232
Total Liabilities Subject to Compromise	**$ 49,736**	**$ 810**	**$ 50,546**

(1) PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

(2) At December 31, 2019, PG&E Corporation and the Utility had $650 million and $21,526 million in aggregate principal amount of pre-petition indebtedness, respectively. Pre-petition financing debt includes accrued contractual interest of $1 million and $286 million for PG&E Corporation and the Utility, respectively, to the Petition Date. Financing debt also includes post-petition interest of $15 million and $638 million for PG&E Corporation and the Utility, respectively, in accordance with the terms of the Noteholder RSA. See Note 5 for details of pre-petition debt reported as LSTC.

(3) See "Pre-petition Wildfire-related claims" in Note 14 for information regarding pre-petition wildfire-related claims reported as LSTC.

(4) 2001 bankruptcy disputed claims includes $14 million of interest recorded at the interest rate specified by FERC in accordance with S35.19a of the Commission's regulations.

Interest on Debt Subject to Compromise

On December 30, 2019, the Bankruptcy Court issued a memorandum decision in which it ruled that the UCC is entitled to post-petition interest at the Federal Judgment Rate of 2.59%. Pursuant to the Noteholder RSA, holders of $11.9 billion in aggregate principal amount of Utility Short-Term Senior Notes, Utility Long-Term Senior Notes and Utility Funded Debt will receive interest at the contractual rate for accrued and unpaid pre-petition interest plus interest at the Federal Judgement Rate on the sum of the applicable principal plus the amount of accrued and unpaid interest for the period commencing the day after the Petition Date and ending on the Effective Date. The $9.58 billion in aggregate principal of Utility Reinstated Senior notes will accrue interest at the contractual rate in accordance with the terms of the Noteholder RSA. From the Petition Date through December 31, 2019, the Utility concluded that interest was probable of being an allowed claim and resumed recording interest on pre-petition debt subject to compromise in accordance with the Noteholder RSA. For more information on Interest on Debt Subject to Compromise, see Note 5 of the Notes to the Consolidated Financial Statements.

Potential Claims

PG&E Corporation and the Utility have received a substantial number of proofs of claim since the Petition Date and are early in the process of reconciling those claims to the amounts listed in the schedules of assets and liabilities. PG&E Corporation and the Utility may ask the Bankruptcy Court to disallow claims that they believe are duplicative, have been later amended or superseded, are without merit, are overstated, were filed late, or should be disallowed for other reasons. Differences between liability amounts recorded by PG&E Corporation and the Utility as liabilities subject to compromise and claims filed by creditors will be investigated and, if necessary, the Bankruptcy Court will make a final determination of the allowed amount of the claim. Differences between those final allowed claims and the liabilities recorded in the Consolidated Balance Sheet will be recognized as reorganization items in PG&E Corporation's and the Utility's Statement of Consolidated Income (Loss) as they are resolved. The determination of how liabilities will ultimately be resolved cannot be made until the Bankruptcy Court approves a plan of reorganization or approves orders related to settlement of specific liabilities. Accordingly, the ultimate amount or resolution of such liabilities is not determinable at this time. The resolution of such claims could result in substantial adjustments to PG&E Corporation's and the Utility's financial statements.

Reorganization Items, Net

Reorganization items, net represent amounts incurred after the Petition Date as a direct result of the Chapter 11 Cases and are comprised of professional fees and financing costs, net of interest income. Reorganization items also include adjustments to reflect the carrying value of LSTC at their estimated allowed claim amounts, as such adjustments are approved by the Bankruptcy Court. Cash paid for reorganization items, net was $15 million and $223 million for PG&E Corporation and the Utility, respectively, during the year ended December 31, 2019. Reorganization items, net from the Petition Date through December 31, 2019 include the following:

	Petition Date Through December 31, 2019		
(in millions)	**Utility**	**PG&E Corporation (1)**	**PG&E Corporation Consolidated**
Debtor-in-possession financing costs	$ 97	$ 17	$ 114
Legal and other	273	19	292
Interest income	(50)	(10)	(60)
Adjustments to LSTC	—	—	—
Total reorganization items, net	**$ 320**	**$ 26**	**$ 346**

(1) PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

The Bankruptcy Court's Decision on its Authority over PG&E Corporation's and the Utility's Rejection of Power Purchase Agreements

On June 7, 2019, the Bankruptcy Court granted PG&E Corporation's and the Utility's motion for declaratory judgment in an adversary proceeding entitled Pacific Gas and Electric Company v. FERC. In its amended declaratory judgment, the Bankruptcy Court found that FERC had no "concurrent jurisdiction, or any jurisdiction, over the determination of whether any rejections of power purchase contracts by either Debtor should be authorized" pursuant to section 365 of the Bankruptcy Code. The Bankruptcy Court also found that the "Debtors do not need approval from the Federal Energy Regulatory Commission to reject any of their power purchase contracts" and that "[a]ny determinations of the Federal Energy Regulatory Commission" that were contrary to these findings "are void, of no force and effect and not binding on this court or either Debtor." The Bankruptcy Court further stated that such determinations include, but are not limited to, those previously made in certain FERC proceedings initiated before the Chapter 11 Cases were filed in connection with power purchase contracts with the Utility (the "FERC Orders").

On June 12, 2019, the Bankruptcy Court certified its amended declaratory judgment for direct appeal to the United States Court of Appeals for the Ninth Circuit. On July 15, 2019, FERC and certain counterparties to the Utility's power purchase agreements filed requests for the Ninth Circuit to permit such direct appeal, which the Ninth Circuit granted on September 17, 2019. On September 17, 2019, the Ninth Circuit granted the requests and docketed both appeals. Opening briefs of FERC and the other appellants were filed on November 20, 2019, PG&E Corporation's and the Utility's answering brief was filed on December 20, 2019, and reply briefs of FERC and the other appellants were filed on January 17, 2020. Separately, on June 26, 2019, the Utility filed a petition for review of the FERC Orders, also in the Ninth Circuit. On September 20, 2019, the Ninth Circuit granted the Utility's motion to align the briefing schedule with the direct appeals from the Bankruptcy Court. The Utility's opening brief was filed on November 20, 2019, FERC's and respondent-intervenors' answering briefs were filed on December 20, 2019, and the Utility's reply brief was filed on January 17, 2020.

The Proposed Plan proposes to assume all power purchase agreements and community choice aggregation servicing agreements.

Resolution of Remaining 2001 Chapter 11 Disputed Claims

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

The Utility's obligations with respect to such claims (all of which arose prior to the initiation of the Utility's pending Chapter 11 Case on January 29, 2019), including pursuant to any prior settlements relating thereto, will not be resolved until after emergence from the Chapter 11 Cases.

NOTE 3: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Loss Contingencies

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

Regulation and Regulated Operations

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

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

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

Revenue Recognition

Revenue from Contracts with Customers

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

Regulatory Balancing Account Revenue

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rate 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, electric and natural gas operating revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

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

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

	Year Ended	
(in millions)	**2019**	**2018**

Electric				
Revenue from contracts with customers				
Residential	$	4,847	$	5,051
Commercial		4,756		4,908
Industrial		1,493		1,532
Agricultural		1,106		1,234
Public street and highway lighting		67		72
Other (1)		168		(720)
Total revenue from contracts with customers - electric		12,437		12,077
Regulatory balancing accounts (2)		303		636
Total electric operating revenue	**$**	**12,740**	**$**	**12,713**
Natural gas				
Revenue from contracts with customers				
Residential	$	2,325	$	2,042
Commercial		605		537
Transportation service only		1,249		1,151
Other (1)		123		75
Total revenue from contracts with customers - gas		4,302		3,805
Regulatory balancing accounts (2)		87		242
Total natural gas operating revenue		**4,389**		**4,047**
Total operating revenues	**$**	**17,129**	**$**	**16,760**

(1) This activity is primarily related to the change in unbilled revenue and amounts subject to refund, partially offset by other miscellaneous revenue items.
(2) These amounts represent revenues authorized to be billed or refunded to customers.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts Receivable

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

Inventories

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

Emission Allowances

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

Property, Plant, and Equipment

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

(in millions, except estimated useful lives)	Estimated Useful Lives (years)	Balance at December 31, 2019	Balance at December 31, 2018
Electricity generating facilities [1]	10 to 75	$ 13,189	$ 13,047
Electricity distribution facilities	10 to 65	35,237	32,926
Electricity transmission facilities	15 to 75	14,281	13,177
Natural gas distribution facilities	20 to 60	14,236	13,296
Natural gas transmission and storage facilities	5 to 66	8,452	8,260
Construction work in progress		2,675	2,564
Other		18	—
Total property, plant, and equipment		**88,088**	**83,270**
Accumulated depreciation		(26,453)	(24,713)
Net property, plant, and equipment		**$ 61,635**	**$ 58,557**

[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 15 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 2019, 3.82% in 2018, and 3.83% in 2017. 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 $55 million and $79 million during 2019, $53 million and $129 million during 2018, and $38 million and $89 million during 2017.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2019 and 2018, including nuclear decommissioning obligations:

(in millions)	**2019**	**2018**
ARO liability at beginning of year	$ 5,994	$ 4,899
Revision in estimated cash flows	(376)	993
Accretion	274	211
Liabilities settled	(38)	(109)
ARO liability at end of year	**$ 5,854**	**$ 5,994**

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

Nuclear Decommissioning Obligation

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

The total nuclear decommissioning obligation accrued was $4.9 billion and $4.7 billion at December 31, 2019 and 2018, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $10.6 billion at December 31, 2019 and 2018.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. See "Enforcement and Litigation Matters" in Note 15 below.

Nuclear Decommissioning Trusts

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

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

Variable Interest Entities

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

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2019, 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, 2019, 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 9, "Derivatives" in Note 10, "Fair Value Measurements" in Note 11, and "Contingencies and Commitments" in Notes 14 and 15 herein.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2019 consisted of the following:

(in millions, net of income tax)	**Pension Benefits**	**Other Benefits**	**Total**
Beginning balance	**$ (21)**	**$ 17**	**$ (4)**
Other comprehensive income before reclassifications:			
Unrecognized net actuarial loss (net of taxes of $24 and $88, respectively)	61	227	288
Regulatory account transfer (net of taxes of $24 and $88, respectively)	(62)	(227)	(289)
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $2 and $4, respectively) (1)	(4)	10	6
Amortization of net actuarial loss (net of taxes of $1 and $1, respectively) (1)	2	(2)	—
Regulatory account transfer (net of taxes of $1 and $3, respectively) (1)	2	(8)	(6)
Net current period other comprehensive loss	**(1)**	**—**	**(1)**
Ending balance	**$ (22)**	**$ 17**	**$ (5)**

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 12 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, 2018 consisted of the following:

(in millions, net of income tax)	**Pension Benefits**	**Other Benefits**	**Total**
Beginning balance	**$ (25)**	**$ 17**	**$ (8)**
Other comprehensive income before reclassifications:			
Unrecognized net actuarial loss (net of taxes of $41 and $9, respectively)	(104)	(23)	(127)
Regulatory account transfer (net of taxes of $41 and $9, respectively)	107	23	130

Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of $2 and $4, respectively) (1)	(4)	10	6
Amortization of net actuarial loss (net of taxes of $2 and $1, respectively) (1)	3	(4)	(1)
Regulatory account transfer (net of taxes of $1 and $3, respectively) (1)	2	(6)	(4)
Net current period other comprehensive loss	**4**	**—**	**4**
Ending balance	**$ (21)**	**$ 17**	**$ (4)**

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 12 below for additional details.)

Recently Adopted Accounting Standards

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which amended the guidance related to the definition of a lease, the recognition of lease assets and liabilities, and the disclosure of key information about leasing arrangements. Under the new standard, a lease exists when an arrangement allows the lessee to control the use of an identified asset for a stated period in exchange for payments. This determination is made at inception of the arrangement. All leases must be recognized as a ROU asset and a lease liability on the balance sheet of the lessee. The ROU asset reflects the lessee's right to use the underlying asset for the lease term and the lease liability reflects the obligation to make the lease payments. PG&E Corporation and the Utility adopted the ASU for leases on January 1, 2019.

PG&E Corporation and the Utility elected certain practical expedients and will carry forward historical conclusions related to (1) contracts that contain leases, (2) existing lease and easement classification, and (3) initial direct costs. After adoption of the new standard, PG&E Corporation and Utility elected not to separate lease and non-lease components. Additionally, PG&E Corporation and the Utility will not restate comparative reporting periods.

The Utility estimates the ROU assets and lease liabilities at net present value using its incremental secured borrowing rates, unless the implicit discount rate in the leasing arrangement can be ascertained. The incremental secured borrowing rate is based on observed market data and other information available at the lease commencement date. The ROU assets and lease liabilities only include the fixed lease payments for arrangements with terms greater than 12 months. Renewal and termination options only impact the lease term if it is reasonably certain that they will be exercised. PG&E Corporation recognizes lease expense on a straight-line basis over the lease term. The Utility recognizes lease expense in conformity with ratemaking.

Operating leases are included in operating lease ROU assets and current and noncurrent operating lease liabilities on the Consolidated Balance Sheets. Financing leases are included in property, plant, and equipment, other current liabilities, and other noncurrent liabilities on the Consolidated Balance Sheets. Financing leases were immaterial for the year ended December 31, 2019.

On January 1, 2019, PG&E Corporation and the Utility recorded ROU assets and lease liabilities of $2.8 billion, representing the net present value of only the fixed lease payments. This amount is presented within the supplemental disclosures of noncash activities. For the year ended December 31, 2019, the Utility made total cash payments, including fixed and variable, of $2.4 billion for operating leases which are presented within operating activities on the Consolidated Statement of Cash Flows. The fixed cash payments for the principal portion of the financing lease liabilities are immaterial and continue to be included within financing activities on the Consolidated Statement of Cash Flows. Any variable lease payments for financing leases are included in operating activities on the Consolidated Statement of Cash Flows.

The majority of the Utility's ROU assets and lease liabilities relate to various power purchase agreements. These power purchase agreements primarily consist of generation plants leased to meet customer demand plus applicable reserve margins. PG&E Corporation and the Utility have also recorded ROU assets and lease liabilities related to property and land arrangements.

At December 31, 2019, the Utility's leases had a weighted average remaining lease term of 5.9 years and a weighted average discount rate of 6.2%.

The following table shows the lease expense recognized for the fixed and variable component of the Utility's lease obligations:

(in millions)	**Year Ended December 31, 2019**
Operating lease fixed cost	$ 686
Operating lease variable cost	1,778
Total operating lease costs	**$ 2,464**

The following table shows the Utility's future expected operating lease payments:

(in millions)	**December 31, 2019**
2020	$ 679
2021	623
2022	548
2023	255
2024	96
Thereafter	596
Total lease payments	**2,797**
Less imputed interest	(518)
Total	**$ 2,279**

The following table shows the Utility's future expected obligations for power purchase and other lease commitments:

(in millions)	**December 31, 2018**
2019	$ 684
2020	677
2021	621
2022	546
2023	252
Thereafter	581
Total lease commitments	**$ 3,361**

Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurements*, which amends the existing guidance relating to the disclosure requirements for fair value measurements. PG&E Corporation and the Utility early adopted the ASU as of December 31, 2019. The adoption of this ASU did not have a material impact on the Consolidated Financial Statements and related disclosures.

Accounting Standards Issued But Not Yet Adopted

Intangibles-Goodwill and Other

In August 2018, the FASB issued ASU No. 2018-15, *Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract*. This ASU became effective for PG&E Corporation and the Utility on January 1, 2020 and did not have a material impact on the Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,* which provides a model, known as the current expected credit loss model, to estimate the expected lifetime credit loss on financial assets, including trade and other receivables, rather than incurred losses over the remaining life of most financial assets measured at amortized cost. The guidance also requires use of an allowance to record estimated credit losses on available-for-sale debt securities. This ASU became effective for PG&E Corporation and the Utility on January 1, 2020 and did not have a material impact on the Consolidated Financial Statements and related disclosures.

NOTE 4: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

	Balance at December 31,		Recovery Period
(in millions)	**2019**	**2018**	
Pension benefits (1)	$ 1,823	$ 1,947	Indefinitely
Environmental compliance costs	1,062	1,013	32 years
Utility retained generation (2)	228	274	8 years
Price risk management	124	90	10 years
Unamortized loss, net of gain, on reacquired debt	63	76	25 years
Catastrophic event memorandum account (3)	656	790	1 - 4 years
Wildfire expense memorandum account (4)	423	94	1 - 4 years
Fire hazard prevention memorandum account (5)	259	263	1 - 4 years
Fire risk mitigation memorandum account (6)	95	—	1 - 4 years
Wildfire mitigation plan memorandum account (7)	558	—	1 - 4 years
Deferred income taxes (8)	252	—	47 years
Other (9)	523	417	Various
Total long-term regulatory assets	**$ 6,066**	**$ 4,964**	

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

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

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

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

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

(6) Includes costs associated with the 2019 Wildfire Mitigation Plan for the period January 1, 2019 through June 4, 2019. Recovery of FRMMA costs are subject to CPUC review and approval.

(7) Includes costs associated with the 2019 Wildfire Mitigation Plan for the period June 5, 2019 through December 31, 2019. Recovery of WMPMA costs are subject to CPUC review and approval.

(8) Represents cumulative differences between amounts recognized for ratemaking purposes and expense recognized in accordance with GAAP. (See Note 9 below.)

(9) December 31, 2019 balance includes $178 million of unamortized debt issuance costs and debt discount that was written off to present the debt subject to compromise at the outstanding face value.

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

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	**2019**	**2018**
Cost of removal obligations (1)	$ 6,456	$ 5,981
Deferred income taxes (2)	—	283
Recoveries in excess of AROs (3)	393	356
Public purpose programs (4)	817	674
Retirement plans (5)	750	421
Other	854	824
Total long-term regulatory liabilities	**$ 9,270**	**$ 8,539**

(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 amounts recognized for ratemaking purposes and expense recognized in accordance with GAAP. (See Note 9 below.)

(3) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 11 below.)

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

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

Regulatory Balancing Accounts

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

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

	Receivable Balance at December 31,	
(in millions)	**2019**	**2018**
Electric distribution	$ —	$ 160
Electric transmission	9	128
Utility generation	—	79
Gas distribution and transmission	363	462
Energy procurement	901	168
Public purpose programs	209	111
Other	632	327
Total regulatory balancing accounts receivable	**$ 2,114**	**$ 1,435**

	Payable Balance at December 31,	
(in millions)	**2019**	**2018**
Electric distribution	$ 31	$ —
Electric transmission	119	134
Gas distribution and transmission	45	9
Energy procurement	649	59
Public purpose programs	559	587
Other	394	287
Total regulatory balancing accounts payable	**$ 1,797**	**$ 1,076**

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

NOTE 5: DEBT

Debtor-In-Possession Facilities

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement, among the Utility, as borrower, PG&E Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent, Citibank, N.A., as collateral agent, and the lenders and issuing banks party thereto (together with such other financial institutions from time to time party thereto, the "DIP Lenders"). The DIP Credit Agreement provides for $5.5 billion in senior secured superpriority debtor in possession credit facilities in the form of (i) a revolving credit facility in an aggregate amount of $3.5 billion (the "DIP Revolving Facility"), including a $1.5 billion letter of credit subfacility, (ii) a term loan facility in an aggregate principal amount of $1.5 billion (the "DIP Initial Term Loan Facility") and (iii) a delayed draw term loan facility in an aggregate principal amount of $500 million (the "DIP Delayed Draw Term Loan Facility," together with the DIP Revolving Facility and the DIP Initial Term Loan Facility, the "DIP Facilities"), subject to the terms and conditions set forth therein. The DIP Credit Agreement also provides for up to $4.0 billion of incremental facilities in the form of (i) one or more additional tranches of term loans or (ii) one or more increases in the aggregate amount of revolving commitments under the DIP Revolving Facility (together, the "Incremental Facilities"), subject to the terms and conditions set forth therein. The Incremental Facilities are uncommitted and would require approval from the Bankruptcy Court.

On the Petition Date, PG&E Corporation and the Utility filed a motion seeking, among other things, interim and final approval of the DIP Facilities, which motion was granted on an interim basis by the Bankruptcy Court following a hearing on January 31, 2019. As a result of the Bankruptcy Court's interim approval of the DIP Facilities and the satisfaction of the other conditions thereof, the DIP Credit Agreement became effective on February 1, 2019 and a portion of the DIP Revolving Facility in the amount of $1.5 billion (including $750 million of the letter of credit subfacility) was made available to the Utility. On March 27, 2019, the Bankruptcy Court approved the DIP Facilities on a final basis, authorizing the Utility to borrow up to the remainder of the DIP Revolving Facility (including the remainder of the $1.5 billion letter of credit subfacility), the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility, in each case subject to the terms and conditions of the DIP Credit Agreement.

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

The proceeds of the borrowings under the DIP Facilities can be used for working capital and general corporate purposes and to pay fees, costs and expenses incurred in connection with the transactions contemplated by the DIP Credit Agreement and professional and other fees and costs of administration incurred in connection with the Chapter 11 Cases. On February 1, 2019, the Utility borrowed $350 million under the DIP Revolving Facility. On April 3, 2019, following the Bankruptcy Court's final approval of the DIP Facilities, the Utility borrowed $1.5 billion under the DIP Initial Term Loan Facility and repaid the $350 million outstanding under the DIP Revolving Facility. On January 29, 2020, the Utility borrowed $500 million under the DIP Delayed Draw Term Loan Facility.

The DIP Facilities mature on December 31, 2020 (the "Maturity Date"), subject to the Utility's option to extend the maturity to December 31, 2021 if certain terms and conditions are satisfied, including the payment of an extension fee equal to 0.25% of the then-outstanding loans and available commitments. As of December 31, 2019, the Utility does not intend to extend the Maturity Date. Both the DIP Initial Term Loan Facility and the Delayed Draw Term Loan bear interest at a spread of 225 basis points over LIBOR. Borrowings under the DIP Revolving Facilities will bear interest based, at the Utility's election, on (1) LIBOR plus an applicable margin of 2.25% or (2) ABR plus an applicable margin of 1.25%. ABR will equal the highest of the following: (i) the administrative agent's announced base rate, (ii) 0.50% above the (x) federal funds effective rate or (y) the overnight federal funds rate, whichever is higher, (iii) one-month LIBOR plus 1.00%, and (iv) zero.

The Utility is also required to pay unused fees of 0.375% per annum in respect of the average daily unutilized commitments under the DIP Revolving Facility. The Utility must also pay (x) a fee equal to the applicable margin with respect to LIBOR loans under the DIP Revolving Facility on the aggregate drawable amount of all outstanding letters of credit under the DIP Revolving Facility and (y) a fronting fee to the relevant issuing DIP Lender equal to 0.125% per annum of the aggregate drawable amount of outstanding letters of credit issued by such issuing DIP Lender.

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

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

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

Debtor-in-Possession Financing

The following table summarizes the Utility's outstanding borrowings and availability under the DIP Facilities at December 31, 2019:

(in millions)	Termination Date	Aggregate Limit	Term Loan Borrowings	Revolver Borrowings	Letters of Credit Outstanding	Aggregate Availability
DIP Facilities	December 2020 (1)	$ 5,500	$ 1,500	$ —	$ 663	$ 3,337

(1) May be extended to December 2021, subject to satisfaction of certain terms and conditions, including payment of a 25 basis point extension fee.

On January 29, 2020, the Utility borrowed $500 million under the DIP Delayed Draw Term Loan Facility.

Debt

The following table summarizes PG&E Corporation's and the Utility's outstanding debt subject to compromise:

(in millions)	Contractual Interest Rates	December 31, 2019	December 31, 2018	Treatment under Proposed Plan (1)
Debt Subject to Compromise (2)				
PG&E Corporation				
Borrowings under Pre-Petition Credit Facility				

PG&E Corporation Revolving Credit Facilities - Stated Maturity: 2022	variable rate (3)	$ 300	$ 300	Repaid in cash
Other borrowings				
Term Loan - Stated Maturity: 2020	variable rate (4)	350	350	Repaid in cash
Total PG&E Corporation Debt Subject to Compromise		**650**	**650**	
Utility				
Senior Notes - Stated Maturity:				
2020	3.50%	800	800	Exchanged for New Utility Short-Term Notes
2021	3.25% to 4.25%	550	550	Exchanged for New Utility Short-Term Notes
2022	2.45%	400	400	Exchanged for New Utility Short-Term Notes
2023	3.25% to 4.25%	1,175	1,175	Reinstated
2024 through 2028	2.95% to 4.65%	3,850	3,850	Reinstated
2034 through 2040	5.40% to 6.35%	5,700	5,700	Exchanged for New Utility Long-Term Notes
2041 through 2042	3.75% to 4.50%	1,000	1,000	Reinstated
2043	4.60%	375	375	Reinstated
2043	5.13%	500	500	Exchanged for New Utility Long-Term Notes
2044 through 2047	3.95% to 4.75%	3,175	3,175	Reinstated
Unamortized discount, net of premium and debt issuance costs		—	(178)	
Total Senior notes, net of premium and debt issuance costs		**17,525**	**17,347**	
Pollution Control Bonds - Stated Maturity:				
Series 2008 F and 2010 E, due 2026 (5)	1.75%	100	100	Repaid in cash
Series 2009 A-B, due 2026 (6)	variable rate (7)	149	149	Exchanged for New Utility Funded Debt Exchange Notes
Series 1996 C, E, F, 1997 B due 2026 (6)	variable rate (8)	614	614	Exchanged for New Utility Funded Debt Exchange Notes
Total pollution control bonds		**863**	**863**	
Borrowings under Pre-Petition Credit Facilities				
Utility Revolving Credit Facilities - Stated Maturity: 2022 (9)	variable rate (10)	2,888	2,965	Exchanged for New Utility Funded Debt Exchange Notes
Other borrowings:				
Term Loan - Stated Maturity: 2019	variable rate (11)	250	250	Exchanged for New Utility Funded Debt Exchange Notes
Total Borrowings under Pre-Petition Credit Facility Subject to Compromise		**3,138**	**3,215**	
Total Utility Debt Subject to Compromise		**21,526**	**21,425**	
Total PG&E Corporation Consolidated Debt Subject to Compromise		**$ 22,176**	**$ 22,075**	

(1) The treatments of debt under the Proposed Plan, described in this column relate only to the treatment of principal amounts and not pre-petition or post-petition interest. The New Utility Short-Term Notes, New Utility Long-Term Senior Notes and New Utility Funded Debt Exchange Notes are described in more detail under "Restructuring Support Agreement with the Ad Hoc Noteholder Committee" in Note 2.

(2) Debt subject to compromise must be reported at the amounts expected to be allowed by the Bankruptcy Court and the carrying values will be adjusted as claims are approved. Total Debt Subject to Compromise does not include accrued contractual interest of $1 million and $286 million for PG&E Corporation and the Utility, respectively, to the Petition Date. Total Debt Subject to Compromise also does not include post-petition interest of $15 million and $638 million for PG&E Corporation and the Utility, respectively, in accordance with the terms of the Noteholder RSA. As of December 31, 2019, PG&E Corporation and the Utility wrote off $178 million of unamortized debt issuance costs and debt discount to present the debt subject to compromise at the outstanding face value. The write-offs are included within long-term regulatory assets in the Consolidated Balance Sheets. See Notes 2 and 4 for further details.

(3) At December 31, 2019, the contractual LIBOR-based interest rate on loans was 3.24%.

(4) At December 31, 2019, the contractual LIBOR-based interest rate on the term loan was 2.96%.

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

(6) Each series of these bonds is supported by a separate direct-pay letter of credit. Following the Utility's Chapter 11 filing, investors in these bonds drew on the letter of credit facilities. The letter of credit facility supporting the Series 2009 A-B bonds matured on June 5, 2019. In December 2015, the maturity dates of the letter of credit facilities supporting the Series 1996 C, E, F, 1997 B bonds were extended to December 1, 2020. Although the stated maturity date of these bonds is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

(7) At December 31, 2019, the contractual interest rate on the letter of credit facilities supporting these bonds was 7.95%.

(8) At December 31, 2019, the contractual interest rate on the letter of credit facilities supporting these bonds ranged from 7.95% to 8.08%.

(9) At December 31, 2019, excludes $22 million of undrawn letters of credit.

(10) At December 31, 2019, the contractual LIBOR-based interest rate on the loans was 3.04%.

(11) At December 31, 2019, the contractual LIBOR-based interest rate on the term loan was 2.36%.

Pollution Control Bonds Subject to Compromise

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

Revolving Credit Facilities Subject to Compromise

PG&E Corporation's and the Utility's revolving credit facilities have been subject to an automatic and immediate acceleration as a result of the Chapter 11 Cases. Prior to the Chapter 11 Cases, proceeds from the revolving credit facilities were used for working capital, the repayment of commercial paper, and other corporate purposes.

Contractual Repayment Schedule

PG&E Corporation and the Utility have entered into the Noteholder RSA with Consenting Noteholders which provides for, among other things, (i) the refinancing of the Utility's senior unsecured debt in satisfaction of all claims arising out of the Utility Short-Term Senior Notes, the Utility Long-Term Senior Notes and the Utility Funded Debt, and (ii) the reinstatement of the Utility Reinstated Senior Notes, in each case pursuant to the Proposed Plan and upon the terms and conditions set forth in the Noteholder RSA. See "Restructuring Support Agreement with the Ad Hoc Noteholder Committee" in Note 2 for further information on the Noteholder RSA.

PG&E Corporation's and the Utility's existing long-term debt is in default, and the Accelerated Direct Financial Obligations became immediately due and payable upon the commencement of the Chapter 11 Cases. PG&E Corporation's and the Utility's combined stated long-term debt principal repayment amounts at December 31, 2019 are reflected in the table below:

(in millions, except interest rates)	2020	2021	2022	2023	2024	Thereafter	Total
PG&E Corporation							
Variable interest rate as of December 31, 2019	2.96 %	— %	3.24 %	— %	— %	— %	2.96 %
Variable rate obligations	$ 350	$ —	$ 300	$ —	$ —	$ —	$ 650
Utility							
Average fixed interest rate	3.50 %	3.80 %	2.31 %	3.83 %	3.60 %	4.80 %	4.52 %
Fixed rate obligations	$ 800	$ 550	$ 500	$ 1,175	$ 800	$ 13,800	$ 17,625
Variable interest rate as of December 31, 2019	various (1)	— %	3.04 %	— %	— %	— %	8.00 %
Variable rate obligations	$ 1,013	$ —	$ 2,888	$ —	$ —	$ —	$ 3,901
Total consolidated debt	**$ 2,163**	**$ 550**	**$ 3,688**	**$ 1,175**	**$ 800**	**$ 13,800**	**$ 22,176**

(1) At December 31, 2019, the average interest rates for the pollution control bonds and the term loan were 8.00% and 2.36%, respectively.

Commercial Paper Programs

As of December 31, 2019, PG&E Corporation and the Utility terminated their respective programs commercial paper programs and had no commercial paper borrowings outstanding.

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 529,236,741 shares of common stock outstanding at December 31, 2019. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2019.

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the year ended December 31, 2019. The remaining gross sales available under this agreement were $246 million.

PG&E Corporation issued 8.9 million shares of common stock under the PG&E Corporation 401(k) plan and share-based compensation plans, for cash proceeds of $85 million, during the year ended December 31, 2019. Beginning January 1, 2019 PG&E Corporation changed its default matching contributions under its 401(k) plan from PG&E Corporation common stock to cash. Beginning in March 2019, at PG&E Corporation's directive, the 401(k) plan trustee began purchasing new shares in the PG&E Corporation common stock fund on the open market rather than directly from PG&E Corporation.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with wildfires. See Wildfire-related contingencies in Note 14 below.

Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. Under their respective pre-petition credit agreements, PG&E Corporation and the Utility were each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. As of the Petition Date, these obligations were automatically stayed and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The DIP Facilities have no such restriction. Additionally, the Utility's net assets, and therefore its ability to pay dividends, are restricted by the CPUC-authorized capital structure, which requires the Utility to maintain, on average, at least 52% equity. Due to the net charges recorded in connection with the 2018 Camp fire and the 2017 Northern California wildfires as of December 31, 2018, the Utility submitted to the CPUC an application for a waiver of the capital structure condition on February 28, 2019. The waiver is subject to CPUC approval. The Utility is not considered to be in violation of these conditions during the period the waiver application is pending resolution. Beginning in 2020, the Utility expects to resume payment of preferred dividends on the Utility's preferred stock, subject to the Utility's Board of Directors' approval. PG&E Corporation does not expect to pay any cash for common stock dividends for at least the next two years, subject to PG&E Corporation's Board of Directors' approval.

Long-Term Incentive Plan

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including stock options, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 12,338,419 shares were available for future awards at December 31, 2019.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2019:

(in millions)	**2019**	**2018**	**2017**
Stock Options	$ 7	$ 10	$ —
Restricted stock units	21	43	40
Performance shares	22	36	45
Total compensation expense (pre-tax)	**$ 50**	**$ 89**	**$ 85**
Total compensation expense (after-tax)	**$ 35**	**$ 63**	**$ 50**

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

Stock Options

The exercise price of stock options granted under the 2014 LTIP and all other outstanding stock options is equal to the market price of PG&E Corporation's common stock on the date of grant. Stock options generally have a 10-year term and vest over three years of continuous service, subject to accelerated vesting in certain circumstances. As of December 31, 2019, $10.5 million of total unrecognized compensation costs related to nonvested stock options were expected to be recognized over a weighted average period of 1.73 years for PG&E Corporation.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method in 2019 and 2018 was $3.87 and $10.24 per share, respectively. The significant assumptions used for shares granted in 2019 were:

	2019	**2018**
Expected stock price volatility	57.00 %	23.00 %
Expected annual dividend payment	— %	3.10 %
Risk-free interest rate	1.51% to 1.52%	2.58 %

Expected life (years)	4.5	6

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

There was no tax benefit recognized from stock options for the year ended December 31, 2019.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2019:

	Number of Stock Option	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	1,522,137	$ 10.24		$ —
Granted	2,866,667	3.87		—
Exercised	—	—		—
Forfeited or expired	(107,401)	10.24		—
Outstanding at December 31	4,281,403	5.98	5.40 years	—
Vested or expected to vest at December 31	4,225,180	5.92	5.36 years	—
Exercisable at December 31	1,433,234	$ 5.99	5.41 years	$ —

Restricted Stock Units

Restricted stock units granted after 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized ratably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2019, 2018, and 2017 was $18.57, $40.92, and $66.95, respectively. The total fair value of restricted stock units that vested during 2019, 2018, and 2017 was $42 million, $41 million, and $57 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2019, $19 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.14 years.

The following table summarizes restricted stock unit activity for 2019:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,979,812	$ 47.66
Granted	74,479	18.57
Vested	(822,249)	51.01
Forfeited	(191,207)	41.49
Nonvested at December 31	**1,040,835**	$ 44.06

Performance Shares

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

Compensation expense attributable to performance shares is generally recognized ratably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value of PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2019, 2018, and 2017 was $15.39, $36.92, and $77.00 respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2019, $11 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.17 years.

The following table summarizes activity for performance shares in 2019:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,438,091	$ 56.32
Granted	130,251	15.39
Vested	(255,324)	40.74
Forfeited (1)	(624,595)	75.54
Nonvested at December 31	**688,423**	$ 36.92

(1) Includes performance shares that expired with zero value as performance targets were not met.

NOTE 7: 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, 2019 and December 31, 2018, 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, 2019, 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, 2019, annual dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid no dividends on preferred stock in 2019, 2018, and $14 million of dividends on preferred stock in 2017 (See "Dividends" in Note 6, above).

NOTE 8: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income (loss) 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 (loss) available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2019, 2018, and 2017.

	Year Ended December 31,		
(in millions, except per share amounts)	**2019**	**2018**	**2017**
Income (loss) available for common shareholders	$ (7,656)	$ (6,851)	$ 1,646
Weighted average common shares outstanding, basic	528	517	512
Add incremental shares from assumed conversions:			
Employee share-based compensation	—	—	1
Weighted average common share outstanding, diluted	528	517	513
Total earnings (loss) per common share, diluted	**$ (14.50)**	**$ (13.25)**	**$ 3.21**

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 9: INCOME TAXES

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

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

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

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

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

	PG&E Corporation			Utility		
	Year Ended December 31,					
(in millions)	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Current:						
Federal	$ 1	$ (5)	$ (10)	$ 4	$ 5	$ 61
State	101	(8)	48	94	(7)	50

Deferred:						
Federal	(2,361)	(2,264)	481	(2,363)	(2,278)	326
State	(1,136)	(1,009)	6	(1,137)	(1,009)	4
Tax credits	(5)	(6)	(14)	(5)	(6)	(14)
Income tax provision (benefit)	**$ (3,400)**	**$ (3,292)**	**$ 511**	**$ (3,407)**	**$ (3,295)**	**$ 427**

The following tables describe net deferred income tax assets and liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	**2019**	**2018**	**2019**	**2018**
Deferred income tax assets:				
Tax carryforwards	$ 1,390	$ 740	$ 1,308	$ 650
Compensation	151	173	92	121
Income tax regulatory liability(1)	—	79	—	79
Wildfire-related claims (2)	6,520	3,433	6,520	3,433
Operating lease liability	642	—	640	—
Other (3)	112	87	121	93
Total deferred income tax assets	**$ 8,815**	**$ 4,512**	**$ 8,681**	**$ 4,376**
Deferred income tax liabilities:				
Property related basis differences	7,984	7,672	7,973	7,660
Regulatory balancing accounts	381	118	381	118
Operating lease right of use asset	642	—	640	—
Income tax regulatory asset(1)	71	—	71	—
Other (4)	57	3	58	3
Total deferred income tax liabilities	**$ 9,135**	**$ 7,793**	**$ 9,123**	**$ 7,781**
Total net deferred income tax liabilities	**$ 320**	**$ 3,281**	**$ 442**	**$ 3,405**

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

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

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

(4) Amount primarily includes an environmental reserve.

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,					
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
Federal statutory income tax rate	21.0 %	21.0 %	35.0 %	21.0 %	21.0 %	35.0 %
Increase (decrease) in income tax rate resulting from:						

State income tax (net of federal benefit) (1)	7.5	7.9	1.5	7.5	7.9	1.6
Effect of regulatory treatment of fixed asset differences (2)	2.8	3.6	(16.5)	2.8	3.6	(16.8)
Tax credits	0.1	0.1	(1.1)	0.1	0.1	(1.1)
Compensation related (3)	—	(0.2)	(1.0)	—	(0.1)	(0.9)
Tax Reform adjustment (4)	—	0.1	6.8	—	0.1	3.0
Other, net (5)	(0.6)	—	(1.1)	(0.5)	—	(0.7)
Effective tax rate	**30.8 %**	**32.5 %**	**23.6 %**	**30.9 %**	**32.6 %**	**20.1 %**

(1) Includes the effect of state flow-through ratemaking treatment.

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 2019 and 2018, the amounts also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December 2017.

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

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

(5) These amounts primarily represent the impact of non-tax deductible bankruptcy costs in 2019 and tax audit settlements in 2017.

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
(in millions)	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Balance at beginning of year	$ 377	$ 349	$ 388	$ 377	$ 349	$ 382
Reductions for tax position taken during a prior year	(1)	(27)	(71)	(1)	(27)	(71)
Additions for tax position taken during the current year	44	55	48	44	55	48
Settlements	—	—	(14)	—	—	(8)
Expiration of statute	—	—	(3)	—	—	(3)
Balance at end of year	**$ 420**	**$ 377**	**$ 349**	**$ 420**	**$ 377**	**$ 349**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2019 for PG&E Corporation and the Utility was $6 million.

PG&E Corporation's and the Utility's unrecognized tax benefits are not likely to change significantly within the next 12 months. As of December 31, 2019, it is reasonably possible that unrecognized tax benefits will decrease by approximately $10 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, 2019, 2018, and 2017, these amounts were immaterial.

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35% to 21% beginning on January 1, 2018 and eliminated bonus depreciation for utilities. The Treasury is still issuing interpretive guidance on various aspects of the Tax Act. If future guidance requires a change in the recorded tax amounts, any necessary change will be reflected in the period such guidance is issued.

Tax settlements

PG&E Corporation's tax returns have been accepted through 2015 for federal income tax purposes, except for a few matters, the most significant of which relate to deductible repair costs for gas transmission and distribution lines of business and tax deductions claimed for regulatory fines and fees assessed as part of the Penalty Decision issued in 2015 for the San Bruno natural gas explosion in September of 2010.

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

Carryforwards

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

(in millions)		**December 31, 2019**	**Expiration Year**
Federal:			
Net operating loss carryforward - Pre-2018	$	3,940	2031 - 2036
Net operating loss carryforward - Post-2017		1,777	N/A
Tax credit carryforward		127	2029 - 2039
State:			
Net operating loss carryforward	$	1,927	N/A
Tax credit carryforward		96	Various

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

NOTE 10: DERIVATIVES

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter. By order dated April 8, 2019, the Bankruptcy Court authorized the Utility to continue these programs in the ordinary course of business in a manner consistent with its pre-petition practices.

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

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

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

Volume of Derivative Activity

The volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume	
		At December 31,	
Underlying Product	Instruments	2019	2018
Natural Gas [1] (MMBtus [2])	Forwards and Swaps	131,896,159	177,750,349
	Options	14,720,000	13,735,405
Electricity (Megawatt-hours)	Forwards and Swaps	18,675,852	3,833,490
	Congestion Revenue Rights [3]	308,467,999	340,783,089

[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, 2019, 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	$ 36	$ (6)	$ 4	$ 34
Other noncurrent assets – other	130	(6)	—	124
Current liabilities – other	(31)	6	2	(23)
Noncurrent liabilities – other	(130)	6	—	(124)
Total commodity risk	**$ 5**	**$ —**	**$ 6**	**$ 11**

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

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 44	$ (1)	$ 89	$ 132
Other noncurrent assets – other	165	—	—	165

Current liabilities – other	(29)	1	7	(21)
Noncurrent liabilities – other	(90)	—	2	(88)
Total commodity risk	**$ 90**	**$ —**	**$ 98**	**$ 188**

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

The majority of the Utility's derivatives instruments, including power purchase agreements, contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies, also known as a credit-risk-related contingent feature. During the first quarter of 2019, multiple credit rating agencies downgraded the Utility's credit ratings below investment grade, which resulted in the Utility posting additional collateral. As of December 31, 2019, the Utility satisfied or has otherwise addressed its obligations related to the credit-risk related contingency features.

NOTE 11: FAIR VALUE MEASUREMENTS

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

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

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

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

	Fair Value Measurements				
	At December 31, 2019				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	$ 1,323	$ —	$ —	$ —	**$ 1,323**
Nuclear decommissioning trusts					
Short-term investments	6	—	—	—	**6**
Global equity securities	2,086	—	—	—	**2,086**
Fixed-income securities	862	728	—	—	**1,590**
Assets measured at NAV	—	—	—	—	**21**
Total nuclear decommissioning trusts (2)	**2,954**	**728**	**—**	**—**	**3,703**
Price risk management instruments (Note 10)					
Electricity	—	2	161	(11)	**152**
Gas	—	3	—	3	**6**
Total price risk management instruments	**—**	**5**	**161**	**(8)**	**158**
Rabbi trusts					

Fixed-income securities	—	100	—	—	**100**
Life insurance contracts	—	73	—	—	**73**
Total rabbi trusts	**—**	**173**	**—**	**—**	**173**
Long-term disability trust					
Short-term investments	10	—	—	—	**10**
Assets measured at NAV	—	—	—	—	**156**
Total long-term disability trust	**10**	**—**	**—**	**—**	**166**
TOTAL ASSETS	**$ 4,287**	**$ 906**	**$ 161**	**$ (8)**	**$ 5,523**
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	$ 1	$ 2	$ 156	$ (13)	**$ 146**
Gas	—	2	—	(1)	**1**
TOTAL LIABILITIES	**$ 1**	**$ 4**	**$ 156**	**$ (14)**	**$ 147**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $530 million, primarily related to deferred taxes on appreciation of investment value.

	Fair Value Measurements				
	At December 31, 2018				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	$ 1,593	$ —	$ —	$ —	**$ 1,593**
Nuclear decommissioning trusts					
Short-term investments	29	—	—	—	**29**
Global equity securities	1,793	—	—	—	**1,793**
Fixed-income securities	661	639	—	—	**1,300**
Assets measured at NAV	—	—	—	—	**16**
Total nuclear decommissioning trusts (2)	**2,483**	**639**	**—**	**—**	**3,138**
Price risk management instruments (Note 10)					
Electricity	—	5	203	51	**259**
Gas	—	1	—	37	**38**
Total price risk management instruments	**—**	**6**	**203**	**88**	**297**
Rabbi trusts					
Fixed-income securities	—	93	—	—	**93**
Life insurance contracts	—	67	—	—	**67**
Total rabbi trusts	**—**	**160**	**—**	**—**	**160**
Long-term disability trust					
Short-term investments	7	—	—	—	**7**
Assets measured at NAV	—	—	—	—	**155**
Total long-term disability trust	**7**	**—**	**—**	**—**	**162**
TOTAL ASSETS	**$ 4,083**	**$ 805**	**$ 203**	**$ 88**	**$ 5,350**

Liabilities:					
Price risk management instruments (Note 10)					
Electricity	4	5	108	(10)	**107**
Gas	—	2	—	—	**2**
TOTAL LIABILITIES	**$ 4**	**$ 7**	**$ 108**	**$ (10)**	**$ 109**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $408 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. There were no material transfers between any levels for the years ended December 31, 2019 and 2018.

Trust Assets

Assets Measured at Fair Value

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

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

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

Assets Measured at NAV Using Practical Expedient

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

Price Risk Management Instruments

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

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

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

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

Level 3 Measurements and Uncertainty Analysis

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 10 above.

(in millions)	Fair Value at At December 31, 2019		Valuation Technique	Unobservable Input	
Fair Value Measurement	**Assets**	**Liabilities**			**Range (1)/Weighted-Average Price (2)**
Congestion revenue rights	$ 140	$ 44	Market approach	CRR auction prices	$ (20.20) - 20.20 / 0.28
Power purchase agreements	$ 21	$ 112	Discounted cash flow	Forward prices	$ 11.77 - 59.38 / 33.62

(1) Represents price per megawatt-hour.
(2) Unobservable inputs were weighted by the relative fair value of the instruments.

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

(1) Represents price per megawatt-hour.

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2019 and 2018, respectively:

Price Risk Management Instruments

(in millions)	2019	2018
Asset (liability) balance as of January 1	$ 95	$ 42
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts [1]	(90)	53
Asset (liability) balance as of December 31	**$ 5**	**$ 95**

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

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility’s variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2019 and 2018, as they are short-term in nature.

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

	At December 31,			
	2019		2018	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 5)				
PG&E Corporation[1]	$ —	$ —	$ 350	$ 350
Utility [1][2]	1,500	1,500	17,450	14,747

[1] On January 29, 2019 PG&E Corporation and the Utility filed for Chapter 11 protection. Debt held by PG&E Corporation became debt subject to compromise and is valued at the allowed claim amount. For more information, see Note 2 and Note 5.

[2] The fair value of the Utility pre-petition debt is $17.9 billion as of December 31, 2019. For more information, see Note 2 and Note 5.

Nuclear Decommissioning Trust Investments

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

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of December 31, 2019				
Nuclear decommissioning trusts				
Short-term investments	$ 6	$ —	$ —	$ 6
Global equity securities	500	1,609	(2)	2,107
Fixed-income securities	1,505	89	(4)	1,590
Total [1]	**$ 2,011**	**$ 1,698**	**$ (6)**	**$ 3,703**
As of December 31, 2018				
Nuclear decommissioning trusts				
Short-term investments	$ 29	$ —	$ —	$ 29

Global equity securities	568	1,246	(5)	1,809
Fixed-income securities	1,288	30	(18)	1,300
Total (1)	**$ 1,885**	**$ 1,276**	**$ (23)**	**$ 3,138**

(1) Represents amounts before deducting $530 million and $408 million at December 31, 2019 and 2018, respectively, primarily related to deferred taxes on appreciation of investment value.

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

(in millions)	**As of December 31, 2019**
Less than 1 year	$ 42
1–5 years	488
5–10 years	397
More than 10 years	663
Total maturities of fixed-income securities	**$ 1,590**

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

(in millions)	**2019**	**2018**	**2017**
Proceeds from sales and maturities of nuclear decommissioning investments	$ 956	$ 1,412	$ 1,291
Gross realized gains on securities	69	54	53
Gross realized losses on securities	(14)	(24)	(11)

NOTE 12: EMPLOYEE BENEFIT PLANS

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

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate ("Pension Plan"). Certain trusts underlying these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. On an annual basis, the Utility funds the pension plans up to the amount it is authorized to recover in rates, $328 million for both 2019 and 2018.

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

On February 27, 2019, PG&E Corporation and the Utility received approval from the Bankruptcy Court to maintain existing pension and other benefit plans during the pendency of the Chapter 11 Cases. (For more information see "First Day Motions" in Note 2 above.)

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 2019 and 2018:

Pension Plan

(in millions)	**2019**	**2018**
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 15,312**	**$ 16,652**
Actual return on plan assets	3,713	(923)
Company contributions	328	334
Benefits and expenses paid	(806)	(751)
Fair value of plan assets at end of year	**$ 18,547**	**$ 15,312**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 17,407**	**$ 18,757**
Service cost for benefits earned	443	514
Interest cost	758	687
Actuarial (gain) loss	2,723	(1,800)
Plan amendments	—	—
Benefits and expenses paid	(806)	(751)
Benefit obligation at end of year (1)	**$ 20,525**	**$ 17,407**
Funded Status:		
Current liability	$ (14)	$ (8)
Noncurrent liability	(1,964)	(2,087)
Net liability at end of year	**$ (1,978)**	**$ (2,095)**

(1) PG&E Corporation's accumulated benefit obligation was $18.4 billion and $15.8 billion at December 31, 2019 and 2018, respectively.

Postretirement Benefits Other than Pensions

(in millions)	**2019**	**2018**
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,258**	**$ 2,420**
Actual return on plan assets	474	(108)
Company contributions	29	31
Plan participant contribution	82	81
Benefits and expenses paid	(165)	(166)
Fair value of plan assets at end of year	**$ 2,678**	**$ 2,258**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,745**	**$ 1,897**
Service cost for benefits earned	56	66
Interest cost	76	69

Actuarial (gain) loss	22	(221)
Benefits and expenses paid	(150)	(150)
Federal subsidy on benefits paid	2	3
Plan participant contributions	81	81
Benefit obligation at end of year	**$ 1,832**	**$ 1,745**
Funded Status: (1)		
Noncurrent asset	$ 879	$ 545
Noncurrent liability	(33)	(32)
Net asset at end of year	**$ 846**	**$ 513**

(1) At December 31, 2019 and 2018, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

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

Components of Net Periodic Benefit Cost

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

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

Pension Plan

(in millions)	**2019**	**2018**	**2017**
Service cost for benefits earned (1)	$ 443	$ 514	$ 472
Interest cost	758	687	714
Expected return on plan assets	(906)	(1,021)	(770)
Amortization of prior service cost	(6)	(6)	(7)
Amortization of net actuarial loss	3	5	22
Net periodic benefit cost	**292**	**179**	**431**
Less: transfer to regulatory account (2)	42	157	(92)
Total expense recognized	**$ 334**	**$ 336**	**$ 339**

(1) A portion of service costs are capitalized pursuant to ASU 2017-07.
(2) The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

Postretirement Benefits Other than Pensions

(in millions)	**2019**	**2018**	**2017**
Service cost for benefits earned (1)	$ 56	$ 66	$ 59
Interest cost	76	69	77
Expected return on plan assets	(123)	(130)	(97)
Amortization of prior service cost	14	14	15

Amortization of net actuarial loss	(3)	(5)	4
Net periodic benefit cost	**$ 20**	**$ 14**	**$ 58**

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

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

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

Components of Accumulated Other Comprehensive Income

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

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2020 are as follows:

(in millions)	**Pension Plan**	**PBOP Plans**
Unrecognized prior service cost	$ (6)	$ 14
Unrecognized net loss	3	(21)
Total	**$ (3)**	**$ (7)**

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,**		
	2019	**2018**	**2017**	**2019**	**2018**	**2017**
Discount rate	3.46 %	4.35 %	3.64 %	3.37 - 3.47%	4.29 - 4.37%	3.60 - 3.67%
Rate of future compensation increases	3.90 %	3.90 %	3.90 %	—	—	—
Expected return on plan assets	5.70 %	6.00 %	6.20 %	3.50 - 6.60%	3.60 - 6.80%	3.30 - 7.10%

The assumed health care cost trend rate as of December 31, 2019 was 6.3%, decreasing gradually to an ultimate trend rate in 2027 and beyond of approximately 4.5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on postretirement benefit obligation	$ 131	$ (129)
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 5.7% compares to a ten-year actual return of 9.3%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 936 Aa-grade non-callable bonds at December 31, 2019. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

Investment Policies and Strategies

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

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

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

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

	Pension Plan			PBOP Plans		
	2020	2019	2018	2020	2019	2018
Global equity securities	30 %	29 %	29 %	28 %	33 %	33 %
Absolute return	2 %	5 %	5 %	2 %	3 %	3 %
Real assets	8 %	8 %	8 %	8 %	6 %	6 %
Fixed-income securities	60 %	58 %	58 %	62 %	58 %	58 %
Total	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**	**100 %**

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

Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2019 and 2018.

	Fair Value Measurements At December 31,							
	2019				2018			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Plan:								
Short-term investments	$ 613	$ 231	$ —	$ 844	$ 333	$ 22	$ —	$ 355
Global equity securities	1,650	—	—	1,650	1,145	—	—	1,145
Absolute Return	—	1	—	1	—	—	—	—
Real assets	548	1	—	549	461	—	—	461
Fixed-income securities	2,227	6,413	15	8,655	1,897	5,216	8	7,121
Assets measured at NAV	—	—	—	6,937	—	—	—	6,202
Total	**$ 5,038**	**$ 6,646**	**$ 15**	**$ 18,636**	**$ 3,836**	**$ 5,238**	**$ 8**	**$ 15,284**
PBOP Plans:								
Short-term investments	$ 37	$ —	$ —	$ 37	$ 33	$ —	$ —	$ 33
Global equity securities	151	—	—	151	115	—	—	115
Real assets	58	—	—	58	50	—	—	50
Fixed-income securities	193	875	1	1,069	153	857	—	1,010
Assets measured at NAV	—	—	—	1,373	—	—	—	1,056
Total	**$ 439**	**$ 875**	**$ 1**	**$ 2,688**	**$ 351**	**$ 857**	**$ —**	**$ 2,264**
Total plan assets at fair value				**$ 21,324**				**$ 17,548**

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net liabilities of $99 million and other net assets of $22 million at December 31, 2019 and 2018, respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

Valuation Techniques

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

Short-Term Investments

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

Global Equity securities

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

Real Assets

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

Fixed-Income securities

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

Assets Measured at NAV Using Practical Expedient

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

Transfers Between Levels

No material transfers between levels occurred in the years ended December 31, 2019 and 2018.

Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for the pension plan that have been classified as Level 3 for the years ended December 31, 2019 and 2018:
(in millions)

For the year ended December 31, 2019		**Fixed-Income**
Balance at beginning of year	$	8
Actual return on plan assets:		
Relating to assets still held at the reporting date		—
Relating to assets sold during the period		—
Purchases, issuances, sales, and settlements:		
Purchases		11
Settlements		(4)
Balance at end of year	**$**	**15**

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

There were no material transfers out of Level 3 in 2019 and 2018.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $328 million to the pension benefit plans and $29 million to the other benefit plans in 2019. 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 2019. The Utility's pension benefits met all the funding requirements under Employee Retirement Income Security Act. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million and $15 million to the pension plan and other postretirement benefit plans, respectively, for 2020.

Benefits Payments and Receipts

As of December 31, 2019, 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
2020	801	92	(8)
2021	874	94	(9)
2022	910	92	(2)
2023	944	95	(2)
2024	975	98	(3)
Thereafter in the succeeding five years	5,238	482	(8)

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 $109 million, $105 million, and $103 million in 2019, 2018, and 2017, respectively. Beginning January 1, 2019 PG&E Corporation changed its default matching contributions under its 401(k) plan from PG&E Corporation common stock to cash. Beginning in March 2019, at PG&E Corporation's directive, the 401(k) plan trustee began purchasing new shares in the PG&E Corporation common stock fund on the open market rather than directly from PG&E Corporation.

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

NOTE 13: 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)	**2019**	**2018**	**2017**
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 4	$ 4	$ 8
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 107	$ 94	$ 65
Utility employee benefit due to PG&E Corporation	42	76	73

At December 31, 2019 and 2018, the Utility had receivables of $60 million and $33 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 $118 million and $38 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 14: WILDFIRE-RELATED CONTINGENCIES

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

Pre-petition Wildfire-Related Claims

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

At December 31, 2019 and December 31, 2018, the Utility's Consolidated Balance Sheets include estimated liabilities in respect of total wildfire-related claims of $25.5 billion and $14.2 billion, respectively. The aggregate liability of $25.5 billion for claims in connection with the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire is comprised of (i) $11 billion for subrogated insurance claimholders pursuant to the Subrogation RSA, plus (ii) $47.5 million for expected professional fees for professionals retained by subrogated insurance claimholders to be reimbursed pursuant to the Subrogation RSA, plus (iii) $1 billion for the Supporting Public Entities with respect to their Public Entity Wildfire Claims pursuant to the PSAs, plus (iv) $13.5 billion for all other wildfire-related claims, including individual wildfire claimholders (including those with uninsured and underinsured property losses) and clean-up and fire suppression costs, pursuant to the TCC RSA. The aggregate liability of $25.5 billion for claims in connection with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire corresponds PG&E Corporation's and the Utility's best estimate of probable losses and is subject to change based on additional information, including the other factors discussed below. (See "2018 Camp Fire, 2017 Northern California Wildfires and 2015 Butte Fire Accounting Charge" below.)

On the Petition Date, all wildfire-related claims were classified as LSTC and all pending litigation was stayed.

In addition, during the year ended December 31, 2019, the Utility incurred legal and other costs of $152 million related to the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire with $245 million corresponding costs in the same period in 2018.

2018 Camp Fire Background

According to Cal Fire, on November 8, 2018 at approximately 6:33 a.m., a wildfire began near the city of Paradise, Butte County, California (the "2018 Camp fire"), which is located in the Utility's service territory. Cal Fire's Camp Fire Incident Information Website as of November 15, 2019 (the "Cal Fire website") indicated that the 2018 Camp fire consumed 153,336 acres. On the Cal Fire website, Cal Fire reported 85 fatalities and the destruction of 18,804 structures resulting from the 2018 Camp fire. There have been no subsequent updates of this information on the Cal Fire website.

On May 15, 2019, Cal Fire issued a news release announcing the results of its investigation into the cause of the 2018 Camp fire. According to the news release:

- Cal Fire determined that the 2018 Camp fire was caused by electrical transmission lines owned and operated by the Utility near Pulga, California.
- Cal Fire identified a second ignition site and stated that the second fire was consumed by the original fire which started earlier near Pulga, California. Cal Fire stated that the cause of the second fire was determined to be "vegetation into electrical distribution lines owned and operated by" the Utility.

Cal Fire indicated in its news release that its investigation report for the 2018 Camp fire has been forwarded to the Butte County District Attorney. The California Attorney General's Office is also investigating the 2018 Camp fire. (See "District Attorneys' Offices' Investigations" below for further information regarding the investigations of the 2018 Camp fire.) As of the date of this filing, Cal Fire's investigation report has not been shared with PG&E Corporation or the Utility.

PG&E Corporation and the Utility accept Cal Fire's determination that the 2018 Camp fire ignited at the first ignition site. PG&E Corporation and the Utility have not been able to form a conclusion as to whether a second fire ignited as a result of vegetation contact with the Utility's facilities.

PG&E Corporation and the Utility are continuing to review the evidence concerning the 2018 Camp fire. PG&E Corporation and the Utility have not yet had access to all of the evidence collected by Cal Fire as part of its investigation or to the investigation report prepared by Cal Fire.

Further, the CPUC's SED also conducted investigations into whether the Utility committed civil violations in connection with the 2018 Camp fire. On November 26, 2019, the SED concluded its investigation into the 2018 Camp fire and released a report alleging certain violations of state law and CPUC regulations. See "Order Instituting an Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire" in Note 15 for a description of these proceedings, including the alleged violations in connection with the 2018 Camp fire.

2017 Northern California Wildfires Background

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

Cal Fire has investigated the causes of the 2017 Northern California wildfires and made the following determinations:

- the Utility's equipment was involved in causing 20 wildfires (the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, 37, Blue, Norrbom, Adobe, Partrick, Pythian, Nuns, Pocket, Atlas, Cascade, Pressley, Point and Youngs fires); and

- the Tubbs fire was caused by a private electrical system adjacent to a residential structure.

As described under the heading "District Attorneys' Offices' Investigations" below, certain of the 2017 Northern California wildfires were the subject of criminal investigations, which have been settled or resulted in PG&E Corporation and the Utility being informed by the applicable district attorneys' office of a decision not to prosecute.

The SED also conducted investigations into whether the Utility committed civil violations in connection with the 2017 Northern California wildfires. See "Order Instituting an Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire" in Note 15 for a description of these proceedings, including the alleged violations in connection with the 2017 Northern California wildfires.

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

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

On October 25, 2019, PG&E Corporation and the Utility submitted a brief to the Bankruptcy Court challenging the application of inverse condemnation to California's investor-owned utilities, including the Utility. The Bankruptcy Court heard argument regarding PG&E Corporation's and the Utility's motion on November 19, 2019. On December 3, 2019, the Bankruptcy Court entered an order holding that the doctrine of inverse condemnation applied to California's investor-owned utilities, including the Utility, and certifying the decision for direct appeal to the U.S. Court of Appeals for the Ninth Circuit. PG&E Corporation and the Utility have appealed this decision; however, as of the date of this filing, this appeal was stayed upon request of PG&E Corporation and the Utility.

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

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

As of January 28, 2019, before the automatic stay arising as a result of the filing of the Chapter 11 Cases, PG&E Corporation and the Utility were aware of approximately 100 complaints on behalf of at least 4,200 plaintiffs related to the 2018 Camp fire, nine of which sought to be certified as class actions. The pending civil litigation against PG&E Corporation and the Utility related to the 2018 Camp fire, which is currently stayed as a result of the commencement of the Chapter 11 Cases, included claims under multiple theories of liability, including, but not limited to, inverse condemnation, trespass, private nuisance, public nuisance, negligence, negligence per se, negligent interference with prospective economic advantage, negligent infliction of emotional distress, premises liability, violations of the Public Utilities Code, violations of the Health & Safety Code, malice and false advertising in violation of the California Business and Professions Code. The plaintiffs principally asserted that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2018 Camp fire. The plaintiffs sought damages and remedies that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, establishment of a class action medical monitoring fund, punitive damages, attorneys' fees and other damages.

As of January 28, 2019, before the automatic stay arising as a result of the filing of the Chapter 11 Cases, PG&E Corporation and the Utility were aware of approximately 750 complaints on behalf of at least 3,800 plaintiffs related to the 2017 Northern California wildfires, five of which sought to be certified as class actions. These cases were coordinated in the San Francisco County Superior Court. As of the Petition Date, the coordinated litigation was in the early stages of discovery. A trial with respect to the Atlas fire was scheduled to begin on September 23, 2019. The pending civil litigation against PG&E Corporation and the Utility related to the 2017 Northern California wildfires included claims under multiple theories of liability, including, but not limited to, inverse condemnation, trespass, private nuisance and negligence. This litigation, including the trial date with respect to the Atlas fire, currently is stayed as a result of the commencement of the Chapter 11 Cases. The plaintiffs principally asserted that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2017 Northern California wildfires. The plaintiffs sought damages and remedies that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees and other damages.

As described below under the heading "Restructuring Support Agreement with the TCC," on December 6, 2019, PG&E Corporation and the Utility entered into a RSA with the TCC, the Consenting Fire Claimant Professionals and the Shareholder Proponents to potentially resolve all wildfire-related claims relating to the 2017 Northern California wildfires and the 2018 Camp fire (other than subrogated insurance claims and Public Entity Wildfire Claims) through the Chapter 11 process. On December 19, 2019, the Bankruptcy Court entered an order granting PG&E Corporation's and the Utility's motion to approve the TCC RSA.

Insurance carriers who have made payments to their insureds for property damage arising out of the 2017 Northern California wildfires filed 52 subrogation complaints in the San Francisco County Superior Court and the Sonoma County Superior Court as of January 28, 2019. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. As of January 28, 2019, before the automatic stay arising as a result of the filing of the Chapter 11 Cases, insurance carriers filed 39 similar subrogation complaints with respect to the 2018 Camp fire in the Sacramento County Superior Court and the Butte County Superior Court. As described below under the heading "Restructuring Support Agreement with Holders of Subrogation Claims," on September 22, 2019, PG&E Corporation and the Utility entered into a RSA with certain holders of insurance subrogation claims to potentially resolve all insurance subrogation claims relating to the 2017 Northern California wildfires and the 2018 Camp fire through the Chapter 11 process. On December 19, 2019, the Bankruptcy Court entered an order granting PG&E Corporation's and the Utility's motion to approve the Subrogation RSA.

Various government entities, including Yuba, Nevada, Lake, Mendocino, Napa and Sonoma Counties and the Cities of Santa Rosa and Clearlake, also asserted claims against PG&E Corporation and the Utility based on the damages that these government entities allegedly suffered as a result of the 2017 Northern California wildfires. Such alleged damages included, among other things, loss of natural resources, loss of public parks, property damages and fire suppression costs. The causes of action and allegations are similar to the ones made by individual plaintiffs and the insurance carriers. With respect to the 2018 Camp fire, Butte County has filed similar claims against PG&E Corporation and the Utility. As described below under the heading "Plan Support Agreements with Public Entities," on June 18, 2019, PG&E Corporation and the Utility entered into agreements with certain government entities to potentially resolve their wildfire-related claims through the Chapter 11 process. The PSAs do not require Bankruptcy Court approval to be effective; however, the Bankruptcy Court must ultimately approve the Proposed Plan that incorporates the terms of the PSAs.

FEMA has filed proofs of claim in the Chapter 11 Cases in the amount of $1.2 billion in connection with the 2017 Northern California wildfires and $2.6 billion in connection with the 2018 Camp fire. FEMA has objected to the classification of their claims under the Proposed Plan as Fire Victim Claims and has indicated that it intends to seek to have its claims classified separately from the Fire Victim Claims. In addition, Cal Fire has filed proofs of claim in the Chapter 11 Cases in the amount of $133 million in connection with the 2017 Northern California wildfires and specifying at least $110 million in connection with the 2018 Camp fire. The OES has filed proofs of claim in the amount of $347 million in connection with the 2017 Northern California wildfires and $2.3 billion in connection with the 2018 Camp fire. The California Department of Transportation has filed proofs of claim in the Chapter 11 Cases in the amount of $217 million in connection with the 2018 Camp fire. Certain other Federal, state and local entities (that are not Supporting Public Entities) have filed proofs of claim in the Chapter 11 Cases in connection with the 2017 Northern California wildfires and the 2018 Camp fire asserting total claims in the amount of $503 million. Proofs of claim have also been filed for unspecified amounts to be determined at a later time. On December 12, 2019, the TCC filed an objection to the claims filed by OES in which it argued that the Bankruptcy Court should disallow the OES claims. On January 9, 2020, the TCC filed a supplement to its objection in which it also objected to the claims filed by FEMA. On February 5, 2020, PG&E Corporation and the Utility joined in the TCC's objection to the OES and FEMA claims. On February 12, 2020, a number of individuals and businesses who hold wildfire-related claims in connection with the 2015 Butte fire, 2017 Northern California wildfires and 2018 Camp fire, as well as certain of the Tubbs Preference Plaintiffs, joined in the TCC's objection to the OES and FEMA claims. Also on February 12, 2020, OES and FEMA filed oppositions to the TCC's objection. A hearing on the objection is scheduled for February 26, 2020.

As described in Note 2, on July 1, 2019, the Bankruptcy Court entered an order approving the Bar Date of October 21, 2019, at 5:00 p.m. (Pacific Time) for filing claims against PG&E Corporation and the Utility relating to the period prior to the Petition Date, including claims in connection with the 2018 Camp fire and the 2017 Northern California wildfires. On November 11, 2019, the Bankruptcy Court entered an order approving a stipulation between PG&E Corporation and the Utility and the TCC to extend the Bar Date for unfiled, non-governmental fire claimants to December 31, 2019, at 5:00 p.m. (Pacific Time). See "Potential Claims" in Note 2 above.

Regardless of any determinations of cause by Cal Fire with respect to any pre-petition fire, ultimately PG&E Corporation's and the Utility's liability will be determined through the Chapter 11 process (including the settlement agreements described below), regulatory proceedings and any potential enforcement proceedings. The timing and outcome of these and other potential proceedings are uncertain.

As discussed under the headings "Plan Support Agreements with Public Entities," "Restructuring Support Agreement with Holders of Subrogation Claims" and "Restructuring Support Agreement with the TCC," PG&E Corporation and the Utility have entered into agreements with certain government entity claimholders, certain insurance subrogation claimholders, and the TCC and the Consenting Fire Claimant Professionals, which agreements would potentially resolve all wildfire-related claims arising from the 2017 Northern California wildfires and the 2018 Camp fire. The resolution of claims asserted by certain federal and California government entities that are not Supporting Public Entities is contemplated by the TCC RSA, however, no government entity is a party to the TCC RSA, and accordingly there can be no assurance that such government entities will support the Proposed Plan or the treatment of their claims in the Chapter 11 cases as provided by the Proposed Plan.

Proceeding in San Francisco County Superior Court for Certain Tubbs Fire-Related Claims (the "Tubbs Trial")

In connection with the TCC RSA, on December 26, 2019, the San Francisco Superior Court entered an order vacating all dates and deadlines in the Tubbs Trial and scheduled a hearing for March 2, 2020 to show cause regarding dismissal of the Tubbs Trial.

On January 6, 2020, in accordance with the terms of the TCC RSA, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking authority to enter into settlement agreements settling and liquidating the claims asserted against PG&E Corporation and the Utility by each of the Tubbs preference plaintiffs. On January 30, 2020, the Bankruptcy Court issued an order granting PG&E Corporation and the Utility's motion to enter into settlement agreements with each of the Tubbs preference plaintiffs.

Wildfire Claims Estimation Proceeding in the U.S. District Court for the Northern District of California (the "Estimation Proceeding")

On July 18, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court for entry of an order establishing procedures and schedules for the estimation of PG&E Corporation's and the Utility's aggregate liability for certain claims arising out of the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire.

On August 21, 2019, the Bankruptcy Court issued recommendations to the District Court recommending the District Court order the partial withdrawal of the reference of the section 502(c) estimation of unliquidated claims arising from the 2018 Camp fire and the 2017 Northern California wildfires. On August 23, 2019, the District Court issued an order adopting the recommendation of the Bankruptcy Court in full and ordering that the reference to the Bankruptcy Court be withdrawn in part.

On October 9, 2019, the District Court issued an initial order for the estimation hearings to begin on February 18, 2020 and conclude on February 28, 2020, with the possibility of an additional week of hearings if warranted.

In connection with the TCC RSA, on December 20, 2019, the District Court entered an order staying the Estimation Proceeding and vacating the February 18, 2020 hearing and all pre-hearing dates.

Plan Support Agreements with Public Entities

On June 18, 2019, PG&E Corporation and the Utility entered into PSAs with certain local public entities providing for an aggregate of $1.0 billion to be paid by PG&E Corporation and the Utility to such public entities pursuant to the Proposed Plan in order to settle such public entities' claims against PG&E Corporation and the Utility relating to the 2018 Camp fire, 2017 Northern California wildfires and 2015 Butte fire (collectively, "Public Entity Wildfire Claims"). PG&E Corporation and the Utility have entered into a PSA with each of the following public entities or groups of public entities, as applicable:

- the City of Clearlake, the City of Napa, the City of Santa Rosa, the County of Lake, the Lake County Sanitation District, the County of Mendocino, Napa County, the County of Nevada, the County of Sonoma, the Sonoma County Agricultural Preservation and Open Space District, the Sonoma County Community Development Commission, the Sonoma County Water Agency, the Sonoma Valley County Sanitation District and the County of Yuba (collectively, the "2017 Northern California Wildfire Public Entities");
- the Town of Paradise;
- the County of Butte;
- the Paradise Recreation & Park District;
- the County of Yuba; and
- the Calaveras County Water District.

For purposes of each PSA, the local public entities that are party to such PSA are referred to herein as "Supporting Public Entities."

Each PSA provides that the Proposed Plan will include, among other things, the following elements:

- following the effective date of the Proposed Plan, PG&E Corporation and the Utility will remit a Settlement Amount (as defined below) in the amount set forth below to the applicable Supporting Public Entities in full and final satisfaction and discharge of their Public Entity Wildfire Claims, and
- subject to the Supporting Public Entities voting affirmatively to accept the Proposed Plan, following the effective date of the Proposed Plan, PG&E Corporation and the Utility will create and promptly fund $10.0 million to a segregated fund to be used by the Supporting Public Entities collectively in connection with the defense or resolution of claims against the Supporting Public Entities by third parties relating to the wildfires noted above ("Third Party Claims").

The "Settlement Amount" set forth in each PSA is as follows:

- for the 2017 Northern California Wildfire Public Entities, $415.0 million (which amount will be allocated among such entities),
- for the Town of Paradise, $270.0 million,
- for the County of Butte, $252.0 million,
- for the Paradise Recreation & Park District, $47.5 million,
- for the County of Yuba, $12.5 million, and
- for the Calaveras County Water District, $3.0 million.

Each PSA provides that, subject to certain terms and conditions, the Supporting Public Entities will support the Proposed Plan with respect to its treatment of their respective Public Entity Wildfire Claims, including by voting to accept the Proposed Plan in the Chapter 11 Cases.

Each PSA may be terminated by the applicable Supporting Public Entities under certain circumstances, including:

- if the Federal Emergency Management Agency or the OES fails to agree that no reimbursement is required from the Supporting Public Entities on account of assistance rendered by either agency in connection with the wildfires noted above, and

- by any individual Supporting Public Entity, if a material amount of Third Party Claims is filed against such Supporting Public Entity and such Third Party Claims are not released pursuant to the Proposed Plan.

Each PSA may be terminated by PG&E Corporation and the Utility under certain circumstances, including if:

- PG&E Corporation and the Utility do not obtain the consent, or the waiver of the lack of consent as a defense, of their insurance carriers for the policy years 2017 and 2018,

- the Board of Directors of either PG&E Corporation or the Utility determines in good faith that continued performance under the PSA would be inconsistent with the exercise of its fiduciary duties, and

- any Supporting Public Entity terminates a PSA, in which case PG&E Corporation and the Utility may terminate any other PSA.

Restructuring Support Agreement with Holders of Subrogation Claims

On September 22, 2019, PG&E Corporation and the Utility entered into a Restructuring Support Agreement with the Consenting Subrogation Creditors of insurance subrogation claims, which agreement was amended and restated on November 1, 2019 and subsequently further amended during November and December 2019 (as amended, the “Subrogation RSA”). The Subrogation RSA provides for an aggregate amount of $11.0 billion (the “Aggregate Subrogation Recovery”) to be paid by PG&E Corporation and the Utility pursuant to the Proposed Plan in order to settle the Subrogation Claims, upon the terms and conditions set forth in the Subrogation RSA. Under the Subrogation RSA, PG&E Corporation and the Utility have also agreed to reimburse the holders of Subrogation Claims for professional fees of up to $55 million, upon the terms and conditions set forth in the Subrogation RSA.

The Subrogation RSA provides that, subject to certain terms and conditions (including that PG&E Corporation and the Utility remain solvent), the Consenting Subrogation Creditors will support the Proposed Plan with respect to its treatment of the Subrogation Claims, including by voting their Subrogation Claims to accept the Proposed Plan in the Chapter 11 Cases.

On September 24, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking authority to enter into, and perform under, the Subrogation RSA and approving the terms of the settlement contemplated under the Subrogation RSA. On December 19, 2019, the Bankruptcy Court entered an order granting PG&E Corporation’s and the Utility’s motion to approve the Subrogation RSA.

On December 31, 2019, the Ad Hoc Noteholder Committee filed a motion with the Bankruptcy Court to vacate the Bankruptcy Court’s order approving the Subrogation RSA in its entirety or, in the alternative, vacate the Bankruptcy Court’s order approving the Subrogation RSA and condition approval of the Subrogation RSA on removal of certain provisions contained therein. Pursuant to the Noteholder RSA, the Ad Hoc Noteholder Committee withdrew its motion on February 5, 2020.

The Subrogation RSA will automatically terminate if (i) the Proposed Plan is not confirmed by June 30, 2020 (or such later date as may be authorized by any amendment to AB 1054) or (ii) the Effective Date does not occur prior to December 31, 2020 (or six months following the deadline for confirmation of the Proposed Plan if such deadline is extended by any amendment to AB 1054).

The Subrogation RSA may be terminated by any Consenting Subrogation Creditor as to itself if the Aggregate Subrogation Recovery is modified. The Subrogation RSA may be terminated by the Consenting Subrogation Creditors holding at least two-thirds of the Subrogation Claims held by Consenting Subrogation Creditors under certain circumstances, including, among others, if (i) they reasonably determine in good faith at any time prior to confirmation of the Proposed Plan that PG&E Corporation and the Utility are insolvent or otherwise unable to raise sufficient capital to pay the Aggregate Subrogation Recovery on the Effective Date, (ii) PG&E Corporation and the Utility breach the terms of the Subrogation RSA or otherwise fail to take certain actions specified in the Subrogation RSA, (iii) the Proposed Plan does not treat the individual plaintiffs' wildfire-related claims consistent with the provisions of AB 1054, (iv) the Bankruptcy Court allows a plan proponent other than PG&E Corporation and the Utility to commence soliciting votes on a plan (other than the Proposed Plan) that incorporates the terms of the settlement contemplated by the Subrogation RSA and PG&E Corporation and the Utility have not already commenced soliciting votes on the Proposed Plan which incorporates such settlement, (v) the Bankruptcy Court confirms a plan other than the Proposed Plan or (vi) the Proposed Plan is modified to be inconsistent with such settlement. The Subrogation RSA may be terminated by PG&E Corporation and the Utility (a) in the event of certain breaches of the Subrogation RSA by Consenting Subrogation Creditors holding at least 5% of the Subrogation Claims held by Consenting Subrogation Creditors or (b) if the Bankruptcy Court confirms a plan other than the Proposed Plan or if the terms of the Proposed Plan related to the settlement contemplated by the Subrogation RSA become unenforceable or are enjoined.

Subject to certain limited exceptions, the valuation of the Subrogation Claims in an aggregate amount of $11.0 billion (the "Allowed Subrogation Claim Amount") will survive any termination of the Subrogation RSA and will be binding on PG&E Corporation and the Utility in the Chapter 11 Cases.

Restructuring Support Agreement with the TCC

On December 6, 2019, PG&E Corporation and the Utility entered into a Restructuring Support Agreement, which was subsequently amended on December 16, 2019, with the TCC, the Consenting Fire Claimant Professionals and the Shareholder Proponents (as amended, the "TCC RSA"). The TCC RSA provides for, among other things, an aggregate of $13.5 billion in value to be provided by PG&E Corporation and the Utility pursuant to the Proposed Plan (together with certain additional rights, the "Aggregate Fire Victim Consideration") in order to settle and discharge the Fire Victim Claims, upon the terms and conditions set forth in the TCC RSA and the Proposed Plan. The Aggregate Fire Victim Consideration is to be funded into a trust (the "Fire Victim Trust") to be established pursuant to the Proposed Plan for the benefit of holders of the Fire Victim Claims and will consist of (a) $5.4 billion in cash contributed on the effective date of the Proposed Plan, (b) $1.35 billion in cash comprising (i) $650 million paid in cash on or before January 15, 2021 and (ii) $700 million paid in cash on or before January 15, 2022, subject to the terms of a tax benefit payment agreement to be entered into between the Fire Victim Trust and the reorganized Utility, and (c) $6.75 billion in common stock of the reorganized PG&E Corporation valued at 14.9 times Normalized Estimated Net Income (as defined in the TCC RSA), except that the Fire Victim Trust's share ownership of the reorganized PG&E Corporation will not be less than 20.9% based on the number of fully diluted shares of the reorganized PG&E Corporation outstanding as of the effective date of the Proposed Plan, assuming the Utility's current allowed ROE. Under certain circumstances, including certain change of control transactions and in connection with the monetization of certain tax benefits related to the payment of wildfire-related claims, the payments described in (b) will be accelerated and payable upon an earlier date. The Aggregate Fire Victim Consideration also includes (1) the assignment by PG&E Corporation and the Utility to the Fire Victim Trust of certain rights and causes of action related to the 2015 Butte fire, the 2017 Northern California wildfires and the 2018 Camp fire (together, the "Fires") that PG&E Corporation and the Utility may have against certain third parties and (2) the assignment of rights under the 2015 and 2016 insurance policies to resolve any claims related to the Fires in those policy years, other than the rights of PG&E Corporation and the Utility to be reimbursed under the 2015 insurance policies for claims submitted prior to the Petition Date.

Under the terms of the Proposed Plan, all Fire Victim Claims, including claims by uninsured and underinsured individual claimholders as well as government entities that are not Supporting Public Entities (including FEMA and OES/Cal Fire), would be settled and discharged in consideration of the payment of the Aggregate Fire Victim Consideration to the Fire Victim Trust. However, the TCC RSA is an agreement among PG&E Corporation and the Utility, the TCC, the Shareholder Proponents, and the Consenting Fire Claimant Professionals, which are attorneys representing individual claimholders. No individual claimholder or government entity (including FEMA and OES/Cal Fire) is a party to the TCC RSA. Accordingly, there can be no assurance that such claimholders or government entities will support the Proposed Plan or the treatment of their Fire Victim Claims in the Chapter 11 Cases as provided in the Proposed Plan.

In addition, each party to the TCC RSA must, among other things, (a) use commercially reasonable efforts to support and cooperate with PG&E Corporation and the Utility to obtain confirmation of the Proposed Plan and any necessary regulatory or other approvals, and (b) oppose efforts and procedures to confirm the Ad Hoc Noteholder Plan. Each party to the TCC RSA also must not, among other things, (1) object to, delay, impede, or take any other action to interfere with acceptance, confirmation or implementation of the Proposed Plan or (2) propose, file or support any other plan of reorganization, restructuring, or sale of assets with respect to PG&E Corporation and the Utility. Each Consenting Fire Claimant Professional must use all reasonable efforts to advise and recommend to its existing and future clients (who hold Fire Victim Claims) to support and vote to accept the Proposed Plan and to opt-in to consensual releases under the Proposed Plan.

The TCC RSA will automatically terminate under certain circumstances, including, among others, if (a) a sufficient number of Fire Victim Claims votes to accept the Proposed Plan such that the class of Fire Victim Claims in the Proposed Plan votes to accept the Proposed Plan under 11 U.S.C. § 1126(c) as determined by the Bankruptcy Court are not made by the later of (i) the voting deadline for the Proposed Plan or (ii) June 30, 2020, (b) the disclosure statement for the Proposed Plan is not approved by the Bankruptcy Court by March 30, 2020 and a motion seeking approval of the settlement of the Estimation Proceeding for the Aggregate Fire Victim Consideration is not filed by March 30, 2020, (c) the Proposed Plan is not confirmed by the Bankruptcy Court by June 30, 2020, or (d) the effective date of the Proposed Plan does not occur prior to August 29, 2020 (which deadlines in (b) through (d) of this paragraph may be extended by consent of PG&E Corporation and the Utility, the TCC, the Shareholder Proponents and the Requisite Consenting Fire Claimant Professionals (as defined below)).

The TCC RSA may be terminated by the TCC or the Requisite Consenting Fire Claimant Professionals (consisting of (a) the TCC, acting by vote of simple majority of its members, and (b) a group of thirteen law firms (subject to addition) that are Consenting Fire Claimant Professionals and whose initial members are specified in the TCC RSA, acting by vote of a simple majority of its members) if (a) PG&E Corporation and the Utility or the Shareholder Proponents breach any of their obligations, representations, warranties or covenants set forth in the TCC RSA, (b) PG&E Corporation and the Utility and the Shareholder Proponents fail to prosecute the Proposed Plan and seek entry of a confirmation order that contains or is otherwise consistent with the terms of the TCC RSA, or propose, pursue or support a Chapter 11 plan of reorganization or confirmation order inconsistent with the terms of the TCC RSA or the Proposed Plan, (c) the Proposed Plan is or is modified to be inconsistent with the terms of the TCC RSA, or (d) the TCC or the Requisite Consenting Fire Claimant Professionals determine on or before the date of the Bankruptcy Court hearing to approve the TCC RSA that Section 4.19(f)(ii) of the Proposed Plan (and any related provisions) has not been modified to their satisfaction. The TCC RSA may be terminated by PG&E Corporation and the Utility or the Shareholder Proponents if (1) either the TCC or Consenting Fire Claimant Professionals that represent in the aggregate more than 8,000 holders of Fire Victim Claims breach any of their obligations, representations, warranties or covenants set forth in the TCC RSA or (2) if the TCC takes any action inconsistent with its obligations under the TCC RSA or fails to take any action required under the TCC RSA.

PG&E Corporation and the Utility' obligation relating to the Tubbs Preference Settlements will survive any termination of the TCC RSA and will be enforceable against PG&E Corporation and the Utility. In addition, the TCC RSA provides that, upon termination of the TCC RSA, (a) the Estimation Proceeding will immediately recommence and (b) all litigation regarding the Tubbs fire, including a determination of whether or not the Utility caused the Tubbs fire, will be determined by the District Court without any reference to any state court proceeding. On December 19, 2019, the Bankruptcy Court entered an order granting PG&E Corporation's and the Utility's motion to approve the TCC RSA.

Pursuant to further discussions with claimants relating to the Ghost Ship fire, PG&E Corporation and the Utility expect certain provisions of the TCC RSA to be superseded by their revised plan of reorganization, and accordingly the above description of the TCC RSA has been revised to reflect the fact that claims arising out of the Ghost Ship fire will be resolved separately from the TCC RSA.

2015 Butte Fire

In September 2015, a wildfire (the "2015 Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. Cal Fire concluded that the 2015 Butte fire was caused when a gray pine tree contacted the Utility's electric line, which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California, County of Sacramento. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council previously had authorized the coordination of all cases in Sacramento County. As of January 28, 2019, 95 known complaints were filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,900 individual plaintiffs representing approximately 2,000 households and their insurance companies. These complaints were part of, or were in the process of being added to, the coordinated proceeding. Plaintiffs sought to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also sought punitive damages. The Utility believes a loss related to punitive damages is unlikely, but possible. Several plaintiffs dismissed the Utility's two vegetation management contractors from their complaints. The Utility does not expect the number of claimants to increase significantly in the future, because the statute of limitations for property damage and personal injury in connection with the 2015 Butte fire has expired. Further, due to the commencement of the Chapter 11 Cases, these plaintiffs have been stayed from continuing to prosecute pending litigation and from commencing new lawsuits against PG&E Corporation or the Utility on account of pre-petition obligations. On January 30, 2019, the Court in the coordinated proceeding issued an order staying the action.

On June 22, 2017, the Superior Court of California, County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inverse condemnation applied to the Utility with respect to the 2015 Butte fire. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability.

On May 1, 2018, the Superior Court of California, County of Sacramento issued its ruling on the Utility's renewed motion in which the court affirmed, with minor changes, its tentative ruling dated April 25, 2018. The Utility reached agreement with two plaintiffs in the litigation to stipulate to judgment against the Utility on inverse condemnation grounds. The court granted the Utility's stipulated judgment motion on November 29, 2018 and the Utility filed its appeal on December 11, 2018. As a result of the filing of the Chapter 11 Cases, these lawsuits, including the trial and the appeal from the stipulated judgment, are stayed.

In addition to the coordinated plaintiffs, Cal Fire, the OES, the County of Calaveras, the Calaveras County Water District, and four smaller public entities (three fire districts and the California Department of Veterans Affairs) brought suit or indicated that they intended to do so. The Utility settled the claims of the three fire protection districts and the Calaveras County Water District.

On April 13, 2017, Cal Fire filed a complaint with the Superior Court of California, County of Calaveras, seeking to recover over $87 million for its costs incurred, which proceeding is now stayed. Prior to the stay, the Utility and Cal Fire were also engaged in a mediation process.

Also, on February 20, 2018, the County of Calaveras filed suit against the Utility and the Utility's vegetation management contractors. The Utility and the County of Calaveras settled the County's claims in November 2018 for $25 million.

Further, in May 2017, the OES indicated that it intended to bring a claim against the Utility related to the Butte fire that it estimated to be approximately $190 million. The Utility has not received any information or documentation from the OES since its May 2017 statement, other than a proof of claim for $107 million filed with the Bankruptcy Court. In June 2017, the Utility entered into an agreement with the OES that extended its deadline to file a claim to December 2020.

PG&E Corporation's and the Utility's obligations with respect to such outstanding claims are expected to be determined through the Chapter 11 process. As described in Note 2, the Bar Date for filing claims against PG&E Corporation and the Utility relating to the period prior to the Petition Date, including claims in connection with the 2015 Butte fire, has passed. PG&E Corporation and the Utility have received numerous proofs of claim in connection with the 2015 Butte fire since the Petition Date and are early in the process of reconciling those claims to the amount listed in the schedules of assets and liabilities. See "Potential Claims" in Note 2 above.

As discussed under the headings “Plan Support Agreements with Public Entities” and “Restructuring Support Agreement with the TCC,” PG&E Corporation and the Utility have entered into agreements to potentially resolve certain government entity claimholders’ wildfire-related claims arising from the 2015 Butte fire as well as with the TCC and the Consenting Fire Claimant Professionals to potentially resolve all wildfire-related claims arising from the 2015 Butte fire held by individual claimholders.

FEMA, the U.S. Department of the Interior, Cal Fire, the OES and certain other Federal, state and local entities (that are not Supporting Public Entities) have filed proofs of claim in the Chapter 11 Cases in connection with the 2015 Butte fire. Proofs of claim have also been filed for unspecified amounts to be determined at a later time.

PG&E Corporation and the Utility may ask the Bankruptcy Court to disallow claims that they believe are duplicative, have been later amended or superseded, are without merit, are overstated or should be disallowed for other reasons. See “Potential Claims” in Note 2.

As described above under the heading “Restructuring Support Agreement with the TCC,” under the TCC RSA, all Fire Victim Claims, including claims by government entities that are not Supporting Public Entities (including FEMA and OES/Cal Fire) would be settled and discharged in consideration of the payment of the Aggregate Fire Victim Consideration to the Fire Victim Trust. However, the TCC RSA is an agreement among PG&E Corporation and the Utility, the TCC, the Shareholder Proponents, and the Consenting Fire Claimant Professionals. No government entity (including FEMA and OES/Cal Fire) is party to the TCC RSA. Accordingly, there can be no assurance that such government entities will support the Proposed Plan or the treatment of their Fire Victim Claims in the Chapter 11 Cases as provided in the Proposed Plan.

2018 Camp Fire, 2017 Northern California Wildfires and 2015 Butte Fire Accounting Charge

In light of the current state of the law and the information currently available to the Utility, including the PSAs, the Subrogation RSA and the TCC RSA, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with the 2018 Camp fire and all 21 of the 2017 Northern California wildfires identified above under the heading “2017 Northern California Wildfire Background”, the reasons for which are discussed in more detail in this section below. PG&E Corporation and the Utility recorded a charge in the amount of $14 billion for the year ended December 31, 2018, a charge in the amount of $3.9 billion for the three months ended June 30, 2019, and a charge in the amount of $2.5 billion for the three months ended September 30, 2019. Based on additional facts and circumstances available to the Utility as of the date of this filing, including the entry into the TCC RSA, PG&E Corporation and the Utility recorded an additional charge for claims in connection with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire in the amount of $5.0 billion for a total charge of $11.4 billion for the year ended December 31, 2019.

In the case of the Tubbs fire and the 37 fire, PG&E Corporation and the Utility continue to believe that if the claims related to these fires were litigated on the merits, it would not be probable that they would incur a loss for such claims. As a result of the entry into the PSAs, the Subrogation RSA and the TCC RSA, PG&E Corporation and the Utility have determined that it is probable they will incur a loss for claims in connection with such fires. With respect to the other 19 of the 2017 Northern California wildfires (the La Porte, McCourtney, Lobo, Honey, Redwood, Sulphur, Cherokee, Blue, Pocket, Atlas, Cascade, Point, Nuns, Norrbom, Adobe, Partrick, Pythian, Youngs and Pressley fires), PG&E Corporation and the Utility previously determined that it is probable they would incur a loss for claims in connection with such fires if such claims were litigated on the merits.

The aggregate liability of $25.5 billion for claims in connection with the 2018 Camp, the 2017 Northern California wildfires and the 2015 Butte fire represents PG&E Corporation's and the Utility's best estimate of probable losses and is subject to change based on additional information. Notwithstanding the entry into the PSAs, the Subrogation RSA and the TCC RSA, there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including whether any termination events are triggered under these agreements, whether the classification and treatment of claims in the Proposed Plan is successfully challenged by claimholders who are not party to a settlement agreement, how the claims filed by Federal, state and local entities are resolved, whether a plan of reorganization incorporating the terms of those settlements is confirmed and the ongoing criminal investigation with respect to the 2018 Camp fire. (See "Third-Party Claims, Investigations and Other Proceedings Related to the 2018 Camp Fire and 2017 Northern California Wildfires" above for a summary of material termination rights under the PSAs, the Subrogation RSA and the TCC RSA.) Many of these factors are beyond the control of PG&E Corporation and the Utility. If one or more of these settlement agreements is terminated, PG&E Corporation's and the Utility's aggregate liability related to the 2018 Camp fire and 2017 Northern California wildfires (and in certain cases, other pre-petition fires) could substantially exceed $25.5 billion. In addition, if these agreements were terminated, regardless of the ultimate determination of PG&E Corporation's and the Utility's liability, such termination would be expected to result in additional delay and expense in the Chapter 11 Cases.

Absent settlement agreements, the process for estimating losses associated with claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the extent to which future claims arise, the amount of fire suppression and clean-up costs or other damages the Utility may be responsible for if found negligent or as estimated in the Chapter 11 Cases.

The $25.5 billion liability does not include any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, or punitive damages, if any, or any losses related to future claims for damages that have not manifested yet, each of which could be significant. The charge also does not include any amounts for potential losses in connection with the wildfire-related securities class action litigation described below or the amount of any penalties or fines that may be imposed by governmental entities, and the amount of any penalties, fines, or restitution orders that might result from any criminal charges brought. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available. As more information becomes available, management estimates and assumptions regarding the financial impact of the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire may change, which could result in material increases to the loss accrued.

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

2019 Kincade Fire

According to Cal Fire, on October 23, 2019 at approximately 9:27 p.m., a wildfire began northeast of Geyserville in Sonoma County, California (the "2019 Kincade fire"), located in the service territory of the Utility. The Cal Fire Kincade Fire Incident Update dated November 20, 2019, 11:02 a.m. Pacific Time (the "incident update") indicated that the 2019 Kincade fire had consumed 77,758 acres. In the incident update, Cal Fire reported no fatalities and four first responder injuries. The incident update also indicates the following: structures destroyed, 374 (consisting of 174 residential structures, 11 commercial structures and 189 other structures); and structures damaged, 60 (consisting of 35 residential structures, one commercial structure and 24 other structures). In connection with the 2019 Kincade fire, state and local officials issued numerous mandatory evacuation orders and evacuation warnings at various times for certain areas of the region. Based on County of Sonoma information, PG&E Corporation and the Utility understand that the geographic zones subject to either a mandatory evacuation order or an evacuation warning between October 23, 2019 and November 4, 2019 included approximately 200,000 persons.

On October 23, 2019, by 3:00 p.m. Pacific Time, the Utility had conducted a PSPS event and turned off the power to approximately 27,837 customers in Sonoma County, including Geyserville and the surrounding area. As part of the PSPS, the Utility's distribution lines in these areas were deenergized. Following the Utility's established and CPUC-approved PSPS protocols and procedures, transmission lines in these areas remained energized.

The Utility has submitted electric incident reports to the CPUC indicating that:

- at approximately 9:19 p.m. Pacific Time on October 23, 2019, the Utility became aware of a transmission level outage on the Geysers #9 Lakeville 230 kV line when the line relayed and did not reclose;
- various generating facilities on the Geysers #9 Lakeville 230kV line detected the disturbance and separated at approximately the same time;
- at approximately 9:21 p.m. Pacific Time, the PG&E Grid Control Center received a report that a fire had started in an area near transmission tower 001/006;
- at approximately 7:30 a.m. Pacific Time on October 24, 2019, a responding Utility troubleman patrolling the Geysers #9 Lakeville 230 kV line observed that Cal Fire had taped off the area around the base of transmission tower 001/006 in the area of the 2019 Kincade fire; and
- on site Cal Fire personnel brought to the troubleman's attention what appeared to be a broken jumper on the same tower.

The cause of the 2019 Kincade fire is under investigation by Cal Fire and the CPUC, and PG&E Corporation and the Utility are cooperating with their investigations. PG&E Corporation and the Utility are also conducting their own investigation into the cause of the 2019 Kincade fire. This investigation is preliminary, and PG&E Corporation and the Utility do not have access to all of the evidence in the possession of Cal Fire or other third parties.

Based on the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, including the information contained in the electric incident report and other information gathered as part of PG&E Corporation's and the Utility's investigation, PG&E Corporation and the Utility believe it is reasonably possible that they will incur a loss in connection with the 2019 Kincade fire. However, due to the preliminary stages of the investigations, lack of access to potentially relevant evidence and the uncertainty as to the cause of the fire and the extent and magnitude of potential damages, PG&E Corporation and the Utility cannot reasonably estimate the amount or range of such possible loss.

While the cause of the 2019 Kincade fire remains under Cal Fire's investigation and there are a number of unknown facts surrounding the cause of the 2019 Kincade fire, the Utility could be subject to significant liability in excess of insurance coverage that would be expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, as well as on the bankruptcy timing and process and the ability of the Utility to participate in the Wildfire Fund. PG&E Corporation and the Utility have received and are responding to data requests from the CPUC's SED relating to the Kincade fire. Various other entities, including law enforcement agencies, may also be investigating the fire. It is uncertain when the investigations will be complete.

Loss Recoveries

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

The Utility has liability insurance from various insurers that provides coverage for third-party liability attributable to the 2015 Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through December 31, 2019, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the 2015 Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility has received $60 million in cumulative reimbursements from the insurance policies of its vegetation management contractors. Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets and was $50 million and $85 million as of December 31, 2019 and December 31, 2018, respectively, reflecting reimbursements of $35 million during the year ended December 31, 2019.

Insurance

In 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019, comprised of $700 million for general liability (subject to an initial self-insured retention of $10 million per occurrence), and $700 million for property damages only, which property damage coverage includes an aggregate amount of approximately $200 million through the reinsurance market where a catastrophe bond was utilized. In 2019, PG&E Corporation and the Utility had liability insurance coverage for wildfire events in an amount of $430 million (subject to an initial self-insured retention of $10 million per occurrence) for the period from August 1, 2019 through July 31, 2020, and approximately $1 billion in liability insurance coverage for non-wildfire events (subject to an initial self-insured retention of $10 million per occurrence), comprised of $520 million for the period from August 1, 2019 through July 31, 2020 and $480 million for the period from September 3, 2019 through September 2, 2020. PG&E Corporation and the Utility continue to pursue additional insurance coverage. Various coverage limitations applicable to different insurance layers could result in uninsured costs in the future depending on the amount and type of damages resulting from covered events.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through December 31, 2019, PG&E Corporation and the Utility recorded $1.38 billion for probable insurance recoveries in connection with the 2018 Camp fire and $843 million for probable insurance recoveries in connection with the 2017 Northern California wildfires. These amounts reflect an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. PG&E Corporation and the Utility intend to seek full recovery for all insured losses.

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

The balances for insurance receivables with respect to the 2018 Camp fire and the 2017 Northern California wildfires are included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets. The balance for insurance receivable for the 2018 Camp fire was $1.38 billion as of December 31, 2019 and December 31, 2018. The balance for insurance receivable for the 2017 Northern California wildfires was $807 million and $829 million as of December 31, 2019 and December 31, 2018, respectively.

Regulatory Recovery

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

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

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the CHT in future applications under Section 451.2(a) of the Public Utilities Code for recovery of costs related to the 2017 Northern California wildfires.

On March 29, 2019, the assigned commissioner issued a scoping memo, which confirmed that the CPUC in this proceeding would establish a CHT methodology applicable only to 2017 fires, to be invoked in connection with a future application for cost recovery and would not determine a specific financial outcome in this proceeding.

On July 8, 2019, the CPUC issued a decision in the CHT proceeding. The CPUC decision provides that "[a]n electrical corporation that has filed for relief under chapter 11 of the Bankruptcy Code may not access the Stress Test to recover costs in an application under Section 451.2(b), because the Commission cannot determine the corporation's 'financial status,' which includes, among other considerations, its capital structure, liquidity needs, and liabilities, as required by Section 451.2(b)." This determination effectively bars PG&E Corporation and the Utility from access to relief under the CHT during the pendency of the Chapter 11 Cases. On August 7, 2019, the Utility submitted to the CPUC an application for rehearing of the decision. The Utility indicated in its application, among other things, that the CPUC's decision "is contrary to law because it bars a utility that has filed for Chapter 11 from accessing the CHT, requires a utility to file a cost recovery application before the CHT will be determined, and erects ratepayer protection mechanisms as an extra-statutory hurdle for accessing the CHT." The Utility also argued that the CPUC should apply the CHT methodology to costs related to the 2018 Camp fire.

The decision otherwise adopts a methodology to determine the CHT based on (1) the maximum additional debt that a utility can take on and maintain a minimum investment grade credit rating; (2) excess cash available to the utility; (3) a potential maximum regulatory adjustment of either 20% of the CHT or 5% of the total disallowed wildfire liabilities, whichever is greater; and (4) an adjustment to preserve for ratepayers any tax benefits associated with the CHT. The decision also requires a utility to include proposed ratepayer protection measures to mitigate harm to ratepayers as part of an application under Section 451.2(b).

Failure to obtain a substantial or full recovery of costs related to wildfires could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows.

Wildfire-Related Derivative Litigation

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

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

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

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

On December 24, 2018, a sixth purported derivative lawsuit, entitled *Bowlinger v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. On February 5, 2019, the plaintiff in *Bowlinger v. Chew, et al.* filed a response to the notice asserting that the automatic stay did not apply to his claims. PG&E Corporation and the Utility accordingly filed a Motion to Enforce the Automatic Stay with the Bankruptcy Court as to the *Bowlinger* action, which was granted. The court has scheduled a case management conference for July 10, 2020.

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

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

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed notices in each of these proceedings on February 1, 2019, reflecting that the proceedings are automatically stayed pursuant to Section 362(a) of the Bankruptcy Code. PG&E Corporation's and the Utility's rights with respect to the derivative claims asserted against former officers and directors of PG&E Corporation and the Utility were assigned to the Fire Victim Trust under the TCC RSA.

Securities Class Action Litigation

Wildfire-Related Class Action

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

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

On February 22, 2019, a purported securities class action was filed in the United States District Court for the Northern District of California, entitled *York County on behalf of the York County Retirement Fund, et al. v. Rambo, et al.* (the "York County Action"). The complaint names as defendants certain current and former officers and directors, as well as the underwriters of four public offerings of notes from 2016 to 2018. Neither PG&E Corporation nor the Utility is named as a defendant. The complaint alleges material misrepresentations and omissions in connection with the note offerings related to, among other things, PG&E Corporation's and the Utility's vegetation management and wildfire safety measures. The complaint asserts claims under Section 11 and Section 15 of the Securities Act of 1933, and seeks unspecified monetary relief, attorneys' fees and other costs, and injunctive relief. On May 7, 2019, the York County Action was consolidated with *In re PG&E Corporation Securities Litigation.*

On May 28, 2019, the plaintiffs in the consolidated securities actions filed a third amended consolidated class action complaint, which includes the claims asserted in the previously-filed actions and names as defendants PG&E Corporation, the Utility, certain current and former officers and directors, and the underwriters. The action remains stayed as to PG&E Corporation and the Utility. On August 28, 2019, the Bankruptcy Court denied PG&E Corporation's and the Utility's request to extend the stay to the claims against the officer, director, and underwriter defendants. On October 4, 2019, the officer, director, and underwriter defendants filed motions to dismiss the third amended complaint, which motions are currently under submission with the District Court.

De-energization Class Action

On October 25, 2019, a purported securities class action was filed in the United States District Court for the Northern District of California, entitled *Vataj v. Johnson et al.* The complaint names as defendants a current director and certain current and former officers of PG&E Corporation. Neither PG&E Corporation nor the Utility is named as a defendant. The complaint alleges materially false and misleading statements regarding PG&E Corporation's wildfire prevention and safety protocols and policies, including regarding the Utility's public safety power shutoffs, that allegedly resulted in losses and damages to holders of PG&E Corporation's securities. The complaint asserts claims under Section 10(b) and Section 20(a) of, and Rule 10b-5 promulgated under, the Exchange Act of 1934, and seeks unspecified monetary relief, attorneys' fees and other costs. On February 3, 2020, the District Court granted a stipulation appointing Iron Workers Local 580 Joint Funds, Ironworkers Locals 40,361 & 417 Union Security Funds and Robert Allustiarti co-lead plaintiffs and approving the selection of the plaintiffs' counsel, and further ordered the parties to submit a proposed schedule by February 13, 2020. On February 11, 2020, the parties submitted a proposed case schedule.

Given the early stages of the litigations, including but not limited to the fact that defendants' motions to dismiss have not yet been heard and no discovery has occurred in the consolidated class action litigation, and that the de-energization class action was recently filed, PG&E Corporation and the Utility are unable to reasonably estimate the amount of any potential loss.

Indemnification Obligations

To the extent permitted by law, PG&E Corporation and the Utility have obligations to indemnify directors and officers for certain events or occurrences while a director or officer is or was serving in such capacity, which indemnification obligations extend to the claims asserted against the directors and officers in the securities class action. PG&E Corporation and the Utility maintain directors and officers insurance coverage to reduce their exposure to such indemnification obligations. PG&E Corporation and the Utility have provided notice to their insurance carriers of the claims asserted in the wildfire-related securities class actions and derivative litigation, and are in communication with the carriers regarding the applicability of the directors and officers insurance policies to those matters. PG&E Corporation and the Utility additionally have potential indemnification obligations to the underwriters for the Utility's note offerings, pursuant to the underwriting agreements associated with those offerings. PG&E Corporation's and the Utility's indemnification obligations to the officers, directors and underwriters may be limited or affected by the Chapter 11 Cases.

District Attorneys' Offices' Investigations

During the second quarter of 2018, Cal Fire issued news releases stating that it referred the investigations related to the McCourtney, Lobo, Honey, Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires to the appropriate county District Attorney's offices for review "due to evidence of alleged violations of state law." On March 12, 2019, the Sonoma, Napa, Humboldt and Lake County District Attorneys announced that they would not prosecute PG&E Corporation or the Utility for the fires in those counties, which include the Sulphur, Blue, Norrbom, Adobe, Partrick, Pythian, Pocket and Atlas fires.

PG&E Corporation and the Utility were the subject of criminal investigations by the Nevada County District Attorney's Office to whom Cal Fire had referred its investigations into the McCourtney and Lobo fires. On July 23, 2019, the Nevada County District Attorney informed PG&E Corporation and the Utility of his decision not to pursue criminal charges in connection with the McCourtney and Lobo fires.

The Honey fire was referred to the Butte County District Attorney's Office, and in October 2018, the Utility reached an agreement to settle any civil claims or criminal charges that could have been brought by the Butte County District Attorney in connection with the Honey fire, as well as the La Porte and Cherokee fires (which Cal Fire did not refer to the Butte County District Attorney for investigation). The settlement provides for funding by the Utility in the amount of up to $1.5 million, not recoverable in rates, for fire prevention work.

On October 9, 2018, the Office of the District Attorney of Yuba County announced its decision not to pursue criminal charges at such time against PG&E Corporation or the Utility pertaining to the Cascade fire. The District Attorney's Office also indicated that it reserved the right "to review any additional information or evidence that may be submitted to it prior to the expiration of the criminal statute of limitations."

In addition, the Butte County District Attorney's Office and the California Attorney General's Office have opened a criminal investigation of the 2018 Camp fire. PG&E Corporation and the Utility have been informed by the Butte County District Attorney's Office and the California Attorney General's Office that a grand jury has been empaneled in Butte County, and the Utility was served with subpoenas in the grand jury investigation. The Utility has produced documents and continues to produce documents and respond to other requests for information and witness testimony in connection with the criminal investigation of the 2018 Camp fire, including, but not limited to, documents related to the operation and maintenance of equipment owned or operated by the Utility. The Utility has also cooperated with the Butte County District Attorney's Office and the California Attorney General's Office in the collection of physical evidence from equipment owned or operated by the Utility. PG&E Corporation and the Utility are unable to predict the timing and outcome of the criminal investigation into the 2018 Camp fire. The Utility could be subject to material fines, penalties, or restitution orders if it is determined that the Utility failed to comply with applicable laws and regulations, as well as non-monetary remedies such as oversight requirements. The criminal investigation is not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases. On October 17, 2019, the Butte County District Attorney's Office and the California Attorney General's Office filed proofs of claim in the Chapter 11 Cases of an undetermined amount on the basis of the criminal investigation of the 2018 Camp fire.

Additional investigations and other actions may arise out of the other 2017 Northern California wildfires and the 2018 Camp fire. The timing and outcome for resolution of the remaining referrals by Cal Fire to the appropriate county District Attorneys' offices are uncertain.

SEC Investigation

On March 20, 2019, PG&E Corporation learned that the SEC's San Francisco Regional Office is conducting an investigation related to PG&E Corporation's and the Utility's public disclosures and accounting for losses associated with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire. PG&E Corporation and the Utility are unable to predict the timing and outcome of the investigation.

Clean-up and Repair Costs

The Utility incurred costs of $772 million for clean-up and repair of the Utility's facilities (including $323 million in capital expenditures) through December 31, 2019, in connection with the 2018 Camp fire. The Utility also incurred costs of $357 million for clean-up and repair of the Utility's facilities (including $180 million in capital expenditures) through December 31, 2019, in connection with the 2017 Northern California wildfires. The Utility is authorized to track and seek recovery of clean-up and repair costs through CEMA. (CEMA requests are subject to CPUC approval.) The Utility capitalizes and records as regulatory assets costs that are probable of recovery. At December 31, 2019, the CEMA regulatory asset balances related to the 2018 Camp fire and 2017 Northern California wildfires were zero and $69 million, respectively, and are included in long-term regulatory assets on the Consolidated Balance Sheets. Additionally, the capital expenditures for clean-up and repair are included in property, plant and equipment on the Consolidated Balance Sheets at December 31, 2019.

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

Wildfire Assistance Fund

On May 24, 2019, the Bankruptcy Court entered an order authorizing PG&E Corporation and the Utility to establish and fund a program (the "Wildfire Assistance Fund") to assist those displaced by the 2018 Camp fire and 2017 Northern California wildfires with the costs of substitute or temporary housing and other urgent needs. The Utility fully funded $105 million into the Wildfire Assistance Fund on August 2, 2019. As of December 31, 2019, the administrator issued claimant payments totaling $64 million under the Wildfire Assistance Fund.

Wildfire Fund under AB 1054

On July 12, 2019, the California Governor signed into law AB 1054, a bill which provides for the establishment of a statewide fund that will be available for eligible electric utility companies to pay eligible claims for liabilities arising from wildfires occurring after July 12, 2019 that are caused by the applicable electric utility company's equipment, subject to the terms and conditions of AB 1054. Eligible claims are claims for third party damages resulting from any such wildfires, limited to the portion of such claims that exceeds the greater of (i) $1 billion in the aggregate in any calendar year and (ii) the amount of insurance coverage required to be in place for the electric utility company pursuant to Section 3293 of the Public Utilities Code, added by AB 1054.

Electric utility companies that draw from the fund will only be required to repay amounts that are determined by the CPUC in an application for cost recovery not to be just and reasonable, subject to a rolling three-year disallowance cap equal to 20% of the electric utility company's transmission and distribution equity rate base. For the Utility, this disallowance cap is expected to be approximately $2.3 billion for the three-year period starting in 2019, subject to adjustment based on changes in the Utility's total transmission and distribution equity rate base. The disallowance cap is inapplicable in certain circumstances, including if the Wildfire Fund administrator determines that the electric utility company's actions or inactions that resulted in the applicable wildfire constituted "conscious or willful disregard for the rights and safety of others," or the electric utility company fails to maintain a valid safety certification. Costs that the CPUC determines to be just and reasonable will not need to be repaid to the fund, resulting in a draw-down of the fund.

The Wildfire Fund and disallowance cap will be terminated when the amounts therein are exhausted. The Wildfire Fund is expected to be capitalized with (i) $10.5 billion of proceeds of bonds supported by a 15-year extension of the Department of Water Resources charge to ratepayers, (ii) $7.5 billion in initial contributions from California's three investor-owned electric utility companies and (iii) $300 million in annual contributions paid by California's three investor-owned electric utility companies. The contributions from the investor-owned electric utility companies will be effectively borne by their respective shareholders, as they will not be permitted to recover these costs from ratepayers. The costs of the initial and annual contributions are allocated among the three investor-owned electric utility companies pursuant to a "Wildfire Fund allocation metric" set forth in AB 1054 based on land area in the applicable utility's service territory classified as high fire threat districts and adjusted to account for risk mitigation efforts. The Utility's initial Wildfire Fund allocation metric is expected to be 64.2% (representing an initial contribution of approximately $4.8 billion and annual contributions of approximately $193 million). In addition, all initial and annual contributions will be excluded from the measurement of the Utility's authorized capital structure. The Wildfire Fund will only be available for payment of eligible claims so long as there are sufficient funds remaining in the Wildfire Fund. Such funds could be depleted more quickly than expected, including as a result of claims made by California's other participating electric utility companies.

AB 1054 also provides that the first $5.0 billion expended in the aggregate by California's three investor-owned electric utility companies on fire risk mitigation capital expenditures included in their respective approved wildfire mitigation plans will be excluded from their respective equity rate bases. The $5.0 billion of capital expenditures will be allocated among the investor-owned electric utility companies in accordance with their Wildfire Fund allocation metrics (described above). AB 1054 contemplates that such capital expenditures may be securitized through a customer charge.

On July 23, 2019, the Utility notified the CPUC of its intent to participate in the Wildfire Fund. On August 7, 2019, PG&E Corporation and the Utility submitted a motion with the Bankruptcy Court for the entry of an order authorizing PG&E Corporation and the Utility to participate in the Wildfire Fund and to make any initial and annual contributions to the Wildfire Fund upon emergence from Chapter 11. On August 26, 2019, the Bankruptcy Court entered an order granting such authorizations. In order to participate in the Wildfire Fund, the Utility must also meet the eligibility and other requirements set forth in AB 1054, and pay its share of the initial contribution to the Wildfire Fund upon emergence from Chapter 11. In such event (assuming the Utility satisfies the eligibility and other requirements set forth in AB 1054), the Wildfire Fund will be available to the Utility to pay for eligible claims arising between the effective date of AB 1054 and the Utility's emergence from Chapter 11, subject to a limit of 40% of the amount of such claims. The balance of any such claims would need to be addressed through the Chapter 11 Cases.

The Utility expects to record its required contributions as an asset and amortize the asset over the estimated life of the Wildfire Fund. The Wildfire Fund asset will be further adjusted for impairment as the assets are used to pay eligible claims, which will result in decreases to the assets available for coverage of future events. AB 1054 does not establish a definite term of the Wildfire Fund; therefore, this accounting treatment is subject to significant judgments and estimates. The assumptions create a high degree of uncertainty related to the estimated useful life of the Wildfire Fund. The most significant assumption is the number and severity of catastrophic fires that could occur in California within the participating electric utilities' service territories during the term of the Wildfire Fund. The Utility intends to utilize historical, publicly available fire-loss data as a starting point; however, future fire-loss can be difficult to estimate due to uncertainties around the impacts of climate change, land use changes, and mitigation efforts by the California electric utility companies. Other assumptions include the estimated cost of wildfires caused by other electric utilities, the amount at which wildfire claims will be settled, the likely adjudication of the CPUC in cases of electric utility-caused wildfires, the level of future insurance coverage held by the electric utilities, and the future transmission and distribution equity rate base growth of other electric utilities. Significant changes in any of these estimates could materially impact the amortization period. There could also be a significant delay between the occurrence of a wildfire and the timing of which the Utility recognizes impairment for the reduction in future coverage, due to the lack of data available to the Utility following a catastrophic event, especially if the wildfire occurs in the service territory of another electric utility. As of December 31, 2019, the Utility has not reflected the required contributions in its Consolidated Financial Statements as it has not yet satisfied all of the Wildfire Fund eligibility criteria pursuant to AB 1054.

In order to participate in the Wildfire Fund, within 60 days of the effective date of AB 1054, the Utility must obtain the Bankruptcy Court's approval of the Utility's election to pay the initial and annual Wildfire Fund contributions upon emergence from Chapter 11, which approval was granted by the Bankruptcy Court on August 26, 2019. The Utility would then be required to pay its share of the initial contribution to the Wildfire Fund upon emergence from Chapter 11, and meet certain eligibility requirements listed below, in order to participate in the Wildfire Fund. In such event (assuming the Utility satisfies the eligibility and other requirements set forth in AB 1054), the Wildfire Fund will be available to the Utility to pay for eligible claims arising between the effective date of AB 1054 and the Utility's emergence from Chapter 11, subject to a limit of 40% of the amount of such claims. The balance of any such claims would need to be addressed through the Chapter 11 Cases. There are several additional eligibility requirements for the Utility, including that by June 30, 2020, the following conditions are satisfied:

- the Utility's Chapter 11 Case has been resolved pursuant to a plan of reorganization or similar document not subject to a stay;
- the Bankruptcy Court has determined that the resolution of the Utility's Chapter 11 Case provides funding or otherwise provides for the satisfaction of any pre-petition wildfire claims asserted against the Utility in the Chapter 11 Case, in the amounts agreed upon in any settlement agreements, authorized by the Bankruptcy Court through an estimation process or otherwise allowed by the Bankruptcy Court;
- the CPUC has approved the Utility's plan of reorganization and other documents resolving its Chapter 11 Case, including the Utility's resulting governance structure as being acceptable in light of the Utility's safety history, criminal probation, recent financial condition and other factors deemed relevant by the CPUC;
- the CPUC has determined that the Utility's plan of reorganization and other documents resolving its Chapter 11 Case are (i) consistent with California's climate goals as required pursuant to the California Renewables Portfolio Standard Program and related procurement requirements and (ii) neutral, on average, to the Utility's ratepayers; and
- the CPUC has determined that the Utility's plan of reorganization and other documents resolving its Chapter 11 Case recognize the contributions of ratepayers, if any, and compensate them accordingly through mechanisms approved by the CPUC, which may include sharing of value appreciation.

NOTE 15: OTHER CONTINGENCIES AND COMMITMENTS

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

Enforcement Matters

U.S. District Court Matters and Probation

In connection with the Utility's probation proceeding, the United States District Court for the Northern District of California has the ability to impose additional probation conditions on the Utility. Additional conditions, if implemented, could be wide-ranging and would impact the Utility's operations, number of employees, costs and financial performance. Depending on the terms of these additional requirements, costs in connections with such requirements could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

CPUC and FERC Matters

Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire

On June 27, 2019, the CPUC issued an OII (the "Wildfires OII") to determine whether the Utility "violated any provision(s) of the California Public Utilities Code (PU Code), Commission General Orders (GO) or decisions, or other applicable rules or requirements pertaining to the maintenance and operation of its electric facilities that were involved in igniting fires in its service territory in 2017." On December 5, 2019, the assigned commissioner issued a second amended scoping memo and ruling that amended the scope of issues to be considered in this proceeding to include the 2018 Camp Fire.

On December 17, 2019, the Utility, the SED of the CPUC, the CPUC's Office of the Safety Advocate, and CUE jointly submitted to the CPUC a proposed settlement agreement in connection with this proceeding and jointly moved for its approval.

In January 2020, several parties that are not part of the settlement agreement, including TURN, The City and County of San Francisco, Thomas Del Monte, the Wild Tree Foundation, and the CPUC's Public Advocates Office, have filed public comments seeking modifications to the settlement agreement. Among other comments, TURN, Cal Advocates, and Del Monte assert that the $1.675 billion in financial obligations imposed on the Utility under the proposed settlement agreement are insufficient and propose additional potential penalties that should be imposed on the Utility. The assigned administrative law judge and/or the assigned commissioner overseeing the proceeding will review the proposed settlement and comments, and may set a hearing, before a final CPUC decision is issued.

Pursuant to the settlement agreement, the Utility agrees to (i) not seek rate recovery of wildfire-related expenses and capital expenditures in future applications in the amount of $1.625 billion, as specified below, and (ii) incur costs of $50 million in shareholder-funded system enhancement initiatives as described further in the settlement agreement. The settlement agreement stipulates that no violations have been identified in the Tubbs fire. As a result of this finding, the settlement agreement does not prevent the Utility from seeking recovery of costs associated with the Tubbs fire through rates. The amounts set forth in the table below include actual recorded costs and forecasted cost estimates for expenses and capital expenditures which the Utility has incurred or will incur to comply with its legal obligations to provide safe and reliable service.

(in millions)

Description(1)	**Expense**	**Capital**	**Total**
Distribution Safety Inspections and Repairs Expense (FRMMA/WMPMA)(2)	$ 236	$ —	$ 236
Transmission Safety Inspections and Repairs Expense (TO)(3)	433	—	433
Vegetation Management Support Costs (FHPMA)	36	—	36
2017 Northern California Wildfires CEMA Expense and Capital (CEMA)	82	66	148
2018 Camp Fire CEMA Expense (CEMA)	435	—	435
2018 Camp Fire CEMA Capital for Restoration (CEMA)	—	253	253
2018 Camp Fire CEMA Capital for Temporary Facilities (CEMA)(4)	—	84	84
Total	**$ 1,222**	**$ 403**	**$ 1,625**

(1) Unless indicated otherwise, all amounts included in the table reflect actual recorded costs for 2019.
(2) Includes $29 million forecasted for 2020.
(3) Transmission amounts are under the FERC's regulatory authority.
(4) Includes $59 million forecasted for 2020.

To the extent the recorded costs for each account apart from Transmission Safety Repairs total an amount that is different from $1.420 billion, then the amount for which the Utility shall not seek rate recovery for Transmission Safety Repairs will be adjusted so that the total amount for which the Utility shall not seek rate recovery equals $1.625 billion.

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.

As of December 31, 2019, PG&E Corporation and the Utility recorded charges of $344 million, related to the portion of the $403 million in disallowed capital that had been spent through December 31, 2019 and, in 2020, expects to record $59 million related to capital expenditures listed in the table above. In addition, PG&E Corporation and Utility recorded charges of approximately $55 million related to vegetation management and catastrophic event expense costs that were previously determined to be probable of recovery and expects to record an additional $29 million in expenses in 2020.

The Utility expects that the system enhancement spending pursuant to the settlement agreement will occur through 2025.

The settlement agreement will become effective upon: (i) approval by the CPUC in a written decision, (ii) following such approval by the CPUC, approval of the United States Bankruptcy Court, Northern District of California, San Francisco Division, and (iii) the effectiveness of a chapter 11 plan of reorganization for the Utility approving the implementation of the settlement agreement. The CPUC may accept, reject or propose alternative terms to the settlement agreement, including imposing penalties on the Utility. The Utility has requested that the CPUC approve the settlement on an expedited basis by the end of February 2020.

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

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

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

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

On March 14, 2019, as directed by the CPUC, the Utility submitted a report that addressed the SED report and responded to the order to show cause. A prehearing conference was held on April 4, 2019, to establish scope and a procedural schedule. The assigned commissioner and ALJ encouraged the SED and the Utility to engage in settlement discussions. On April 24, 2019, the Utility provided notice of a settlement conference and the parties began ongoing settlement discussions. On May 7, 2019, the assigned commissioner issued a scoping memo and ruling that included within the proceedings, in addition to the issues identified in the OII relating to the Utility's locate and mark procedures, issues relating to locating and marking of the Utility's electric distribution facilities and the use of "qualified electrical workers" for locating and marking underground infrastructure. On July 24, 2019, the SED submitted its opening testimony to the CPUC. A status conference with the ALJ was held on July 30, 2019. Intervenor testimony was submitted on August 16, 2019, and the Utility's reply testimony was submitted on September 18, 2019.

On October 3, 2019, the Utility, SED and CUE jointly submitted to the CPUC a proposed settlement agreement. Pursuant to the settlement agreement, the Utility agreed to a total financial remedy of $65 million, comprised of (i) a fine of $5 million funded by shareholders to be paid to the General Fund of the State of California pursuant to, and in accordance with, the time frame and other provisions governing distributions as set forth in the Chapter 11 plan of reorganization for the Utility as confirmed by the Bankruptcy Court; and (ii) $60 million in shareholder-funded initiatives undertaken to enhance, among other things, the Utility's locate and mark compliance and capabilities and the reliability of the Underground Service Alert ticket management information that the Utility maintains in the ordinary course of its business.

In accordance with the settlement agreement, shareholder-funded system enhancements will include, among other things, locate and mark ticket compliance audits to verify accurate categorization of timeliness, compliance audits using field reviews of gas and electric locate and mark tickets to assess performance, procedure adherence and compliance, and additional locate and mark staff. The expenditure of any sums not fully expended within three years of the effective date of the settlement agreement will be subject to further agreement among the parties.

On January 17, 2020, the presiding officer issued a decision requiring modifications to the settlement agreement that would (i) require an extension of certain compliance audits required by the settlement agreement, at a cost to shareholders of $6 million, (ii) an additional fine of $39 million funded by shareholders to be paid to the General Fund of the State of California, (iii) certain additional system enhancements, and (iv) requirements on the previously proposed system enhancements, including a requirement that any funds remaining after completion of the system enhancements are not to be spent as agreed to by the parties, but is to be paid to the General Fund. On February 6, 2020, the settling parties filed a motion accepting the presiding officer's proposed modifications to the settlement and proposing alternative relief. On February 14, 2020, the presiding officer issued a decision noting that the settling parties had accepted the modifications included in the presiding officer's decision and rejecting the alternative relief proposed by the settling parties. The deadline for parties to file an appeal of the presiding officer's decision is February 18, 2020.

As of December 31, 2019, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $44 million accrual.

This proceeding is not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of this proceeding are stayed.

OII into Compliance with Ex Parte Communication Rules

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 CPUC would later divide the OII into two phases, pertaining to different sets of communications.

Regarding phase one, on April 26, 2018, the CPUC adopted the settlement agreement jointly submitted to the CPUC on March 28, 2017, as modified (the "settlement agreement") by the Utility, the Cities of San Bruno and San Carlos, PAO, the SED, and TURN. The decision resulted in a total penalty of $97.5 million comprised of: (1) a $12 million payment to the California General Fund, (2) forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million), (3) a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over the Utility's next GRC cycle (i.e., the 2020 GRC), and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above.

As a result of the CPUC's April 26, 2018 decision, on May 17, 2018, the Utility made a $12 million payment to the California General Fund and $6 million payments to each of the Cities of San Bruno and San Carlos. At December 31, 2019, the Utility has refunded $63.5 million of GT&S revenue requirements for the years 2018 and 2019. In accordance with accounting rules, adjustments related to revenue requirements are recorded in the periods in which they are incurred.

Regarding phase two, on December 5, 2019, the CPUC approved a settlement agreement between the Cities of San Bruno and San Carlos, PAO, the SED, TURN, and the Utility. Under the settlement agreement, the Utility will pay a total penalty of $10 million comprised of: (1) a $2 million payment to the California General Fund, (2) forgoing collection of $5 million in revenue requirements during the term of its 2019 GT&S rate case, (3) forgoing collection of $1 million in revenue requirement during the term of its 2020 GRC cycle, and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $2 million ($1 million to each city). By the terms of the settlement, the financial remedies will not be implemented until a plan of reorganization is approved in the Chapter 11 Cases. In accordance with accounting rules, adjustments related to forgone collections would be recorded in the periods in which they are incurred.

As of December 31, 2019, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $4 million accrual for the amounts payable to the California General Fund and the Cities of San Bruno and San Carlos.

Transmission Owner Rate Case Revenue Subject to Refund

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

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case and the Utility filed initial briefs on October 31, 2018, in response to the ALJ's recommendations. The Utility expects the FERC to issue a decision in the TO18 rate case in 2020, however, the timing of that decision is uncertain, and it will likely be the subject of requests for rehearing and appeal.

On September 21, 2018, the Utility filed an all-party settlement with the FERC, which was approved by FERC on December 20, 2018, in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined upon issuance of a final unappealable decision in TO18.

On November 30, 2018, the FERC issued an order accepting the Utility's October 2018 filing of its TO20 formula rate case, subject to hearings and refund, and established May 1, 2019, as the effective date for rate changes. The FERC also ordered that the hearings will be held in abeyance pending settlement discussions among the parties.

The Utility is unable to predict the timing or outcome of FERC's decisions in the TO18 and TO19 proceedings or the timing or outcome of the TO20 proceeding.

Natural Gas Transmission Pipeline Rights-of-Way

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

Other Matters

PG&E Corporation and the Utility are subject to various claims, lawsuits, and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $116 million at December 31, 2019 and were included in LSTC. Accruals for contingencies related to such matters totaled $98 million at December 31, 2018. These amounts were included in Other current liabilities in the Consolidated Balance Sheets. On the Petition Date, these amounts were moved to LSTC. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows.

PSPS Class Action

On December 19, 2019, a complaint was filed in the United States Bankruptcy Court for the Northern District of California naming PG&E Corporation and the Utility. The plaintiff seeks certification of a class consisting of all California residents and business owners who had their power shut off by the Utility during the October 9, October 23, October 26, October 28, or November 20, 2019 power outages and any subsequent voluntary outages occurring during the course of litigation. The plaintiff alleges that the necessity for the October and November 2019 power shutoff events was caused by the Utility's negligence in failing to properly maintain its electrical lines and surrounding vegetation. The complaint seeks up to $2.5 billion in special and general damages, punitive and exemplary damages and injunctive relief to require the Utility to properly maintain and inspect its power grid.

PG&E Corporation and the Utility believe the allegations are without merit and intend to defend this lawsuit vigorously. On January 21, 2020, PG&E Corporation and the Utility filed a motion to dismiss the complaint or in the alternative strike the class action allegations. The motion to dismiss and strike is set to be heard by the Bankruptcy Court on March 10, 2020. At this stage of the litigation, PG&E Corporation and the Utility are unable to predict the ultimate outcome or estimate a range of reasonably possible losses.

2015 GT&S Rate Case Disallowance of Capital Expenditures

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted in the prior GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. Additional charges may be required in the future based on the outcome of the CPUC's audit of 2011 through 2014 capital spending. Capital disallowances are reflected in operating and maintenance expenses in the Consolidated Statements of Income.

Environmental Remediation Contingencies

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

	Balance at	
(in millions)	**December 31, 2019**	**December 31, 2018**
Topock natural gas compressor station	$ 362	$ 369
Hinkley natural gas compressor station	138	146
Former manufactured gas plant sites owned by the Utility or third parties (1)	568	520
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2)	101	111
Fossil fuel-fired generation facilities and sites (3)	106	137
Total environmental remediation liability	**$ 1,275**	**$ 1,283**

(1) Primarily driven by the following sites: Vallejo, San Francisco East Harbor and Outside East Harbor, Napa, Beach Street and San Francisco North Beach.
(2) Primarily driven by Geothermal landfill and Shell Pond site.
(3) Primarily driven by the San Francisco Potrero Power Plant.

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

The Utility's environmental remediation liability at December 31, 2019, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans and the Utility's time frame for remediation. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material effect on results of operations, financial condition, liquidity, and cash flows during the period in which they are recorded. At December 31, 2019, the Utility expected to recover $950 million of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

Natural Gas Compressor Station Sites

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

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California DTSC and the U.S. Department of the Interior. On April 24, 2018, the DTSC authorized the Utility to build an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. Construction activities began in October 2018 and will continue for several years. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $208 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. A draft background report is expected to be issued in 2020 and finalized thereafter. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $128 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $626 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites often involve long-term remediation. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $77 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Fossil Fuel-Fired Generation Sites

In 1998, the Utility divested its generation power plant business as part of generation deregulation. Although the Utility sold its fossil-fueled power plants, the Utility retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $82 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Insurance

Wildfire Insurance

In 2018, PG&E Corporation and the Utility renewed their liability insurance coverage for wildfire events in an aggregate amount of approximately $1.4 billion for the period from August 1, 2018 through July 31, 2019, comprised of $700 million for general wildfire liability in policies covering wildfire and non-wildfire events (subject to an initial self-insured retention of $10 million per occurrence), and $700 million for wildfire property damages only, which included approximately $200 million of coverage through the use of a catastrophe bond. In 2019, PG&E Corporation and the Utility has liability insurance coverage for wildfire events in an amount of $430 million (subject to an initial self-insured retention of $10 million per occurrence) for the period of August 1, 2019 through July 31, 2020, and approximately $1 billion in liability insurance coverage for non-wildfire events (subject to an initial self-insured retention of $10 million per occurrence), comprised of $520 million for the period of August 1, 2019 through July 31, 2020 and $480 million for the period of September 3, 2019 through September 2, 2020. PG&E Corporation and the Utility continue to pursue additional insurance coverage. Various coverage limitations applicable to different insurance layers could result in uninsured costs in the future depending on the amount and type of damages resulting from covered events.

PG&E Corporation's and the Utility's cost of obtaining the wildfire and non-wildfire insurance coverage in place for the period of August 1, 2019 through September 2, 2020 is approximately $212 million, compared to the approximately $50 million that the Utility recovered in rates during the year ended December 31, 2019. The Utility has sought recovery of certain premium costs paid in excess of the amount the Utility currently is recovering from customers through the GRC period ended December 31, 2019. The Utility's 2020 GRC settlement agreement includes a new two-way balancing account that would allow the Utility to pass through actual insurance premium costs for up to $1.4 billion in coverage. The Utility is unable to predict the timing and outcome of the 2020 GRC proceeding.

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through December 31, 2019, PG&E Corporation and the Utility recorded $1.38 billion for probable insurance recoveries in connection with the 2018 Camp fire and $843 million for probable insurance recoveries in connection with the 2017 Northern California wildfires. These amounts reflect an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL, a mutual insurer owned by utilities with nuclear facilities, and European Mutual Association for Nuclear Insurance (EMANI), covering nuclear or non-nuclear events at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3.

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. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.7 billion per non-nuclear incident for Diablo Canyon. For Humboldt Bay Unit 3, NEIL provides up to $131 million of coverage for nuclear and non-nuclear property damages.

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

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

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of the policy renewal on April 1, 2020, the maximum aggregate annual retrospective premium obligation for the Utility would be approximately $44 million. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $4 million, as of the policy renewal on April 1, 2020.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $14.0 billion. The Utility purchased the maximum available public liability insurance of $450 million for Diablo Canyon. The balance of the $14.0 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $275 million per nuclear incident under this loss sharing program, with payments in each year limited to a maximum of $41 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years.

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

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, 2019:

	Power Purchase Agreements					
(in millions)	**Renewable Energy**	**Conventional Energy**	**Other**	**Natural Gas**	**Nuclear Fuel**	**Total**
2020	$ 2,230	$ 640	$ 82	$ 411	$ 151	$ 3,514
2021	2,234	582	65	155	64	3,100
2022	2,021	511	61	155	54	2,802
2023	1,941	224	60	155	49	2,429
2024	1,917	72	60	155	47	2,251
Thereafter	22,853	351	94	346	—	23,644
Total purchase commitments	**$ 33,196**	**$ 2,380**	**$ 422**	**$ 1,377**	**$ 365**	**$ 37,740**

Subject to certain exceptions, under the Bankruptcy Code, PG&E Corporation and the Utility may assume, assign or reject certain executory contracts, subject to the approval of the Bankruptcy Court and satisfaction of certain other conditions. (For more information see "The Bankruptcy Court's Decision on its Authority over PG&E Corporation's and the Utility's Rejection of Power Purchase Agreements" in Note 2 above.)

Third-Party Power Purchase Agreements

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

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

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

Other Power Purchase Agreements. The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. As of December 31, 2019, QF contracts in operation expire at various dates between 2019 and 2049. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The costs incurred for all power purchases and electric capacity amounted to $3.0 billion in 2019, $3.1 billion in 2018, and $3.3 billion in 2017.

Natural Gas Supply, Transportation, and Storage Commitments

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

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to $0.9 billion in 2019, $0.6 billion in 2018, and $0.9 billion in 2017.

Nuclear Fuel Agreements

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

Payments for nuclear fuel amounted to $74 million in 2019, $73 million in 2018, and $83 million in 2017.

Other Commitments

PG&E Corporation and the Utility have other commitments primarily related to office facilities and land leases, which expire at various dates between 2020 and 2052. At December 31, 2019, the future minimum payments related to these commitments were as follows:

(in millions)	Other Commitments
2020	$ 45
2021	39

2022		31
2023		24
2024		14
Thereafter		111
Total minimum lease payments	**$**	**264**

Payments for other commitments amounted to $48 million in 2019, $43 million in 2018, and $45 million in 2017. Certain office facility leases contain escalation clauses requiring annual increases in rent. The rents may increase by a fixed amount each year, a percentage of the base rent, or the consumer price index. There are options to extend these leases for one to five years.

One of these commitments is treated as a financing lease. At December 31, 2019 and 2018, net financing leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $9 million and $11 million including accumulated amortization of $9 million and $8 million, respectively. The present value of the future minimum lease payments due under these agreements included $2 million and $2 million in Current Liabilities and $7 million and $9 million in Noncurrent Liabilities on the Consolidated Balance Sheet, at December 31, 2019 and 2018, respectively.

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				6,290,667
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(1,479,837)
3	Preceding Quarter/Year to Date Changes in Fair Value				(5,797,538)
4	Total (lines 2 and 3)				(7,277,375)
5	Balance of Account 219 at End of Preceding Quarter/Year				(986,708)
6	Balance of Account 219 at Beginning of Current Year				(986,708)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				597,861
8	Current Quarter/Year to Date Changes in Fair Value				1,406,636
9	Total (lines 7 and 8)				2,004,497
10	Balance of Account 219 at End of Current Quarter/Year				1,017,789

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			6,290,667		
2			(1,479,837)		
3			(5,797,538)		
4			(7,277,375)	(6,818,107,469)	(6,825,384,844)
5			(986,708)		
6			(986,708)		
7			597,861		
8			1,406,636		
9			2,004,497	(7,621,767,673)	(7,619,763,176)
10			1,017,789		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	76,658,863,353	55,911,704,766
4	Property Under Capital Leases	2,296,947,146	2,182,593,816
5	Plant Purchased or Sold	-217,498	5,412
6	Completed Construction not Classified	14,962,324,268	8,600,576,504
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	93,917,917,269	66,694,880,498
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,672,175,058	2,102,914,386
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	96,590,092,327	68,797,794,884
14	Accum Prov for Depr, Amort, & Depl	39,506,642,610	28,362,712,646
15	Net Utility Plant (13 less 14)	57,083,449,717	40,435,082,238
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	38,407,333,617	28,298,971,651
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	8,532,670	
21	Amort of Other Utility Plant	1,090,776,323	63,740,995
22	Total In Service (18 thru 21)	39,506,642,610	28,362,712,646
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)	39,506,642,610	28,362,712,646

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
14,590,870,382				6,156,288,205	3
41,260				114,312,070	4
-180,565				-42,345	5
5,514,262,964				847,484,800	6
					7
20,104,994,041				7,118,042,730	8
					9
					10
298,494,852				270,765,820	11
					12
20,403,488,893				7,388,808,550	13
8,155,806,446				2,988,123,518	14
12,247,682,447				4,400,685,032	15
					16
					17
8,148,489,625				1,959,872,341	18
					19
8,532,670					20
-1,215,849				1,028,251,177	21
8,155,806,446				2,988,123,518	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
8,155,806,446				2,988,123,518	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	233,949,233	77,742,003
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	233,949,233	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	427,381,622	177,014,381
10	SUBTOTAL (Total 8 & 9)	427,381,622	
11	Spent Nuclear Fuel (120.4)	2,359,998,526	206,971,019
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,630,936,779	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	390,392,602	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
	177,014,380	134,676,856	3
			4
			5
		134,676,856	6
			7
			8
	206,971,019	397,424,984	9
		397,424,984	10
		2,566,969,545	11
			12
-112,531,507		2,743,468,286	13
		355,603,099	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	03/25/2020	2019/Q4

FOOTNOTE DATA

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

Cost of fuel inserted into reactor during 2019; 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 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	138,759,137	242,342
4	(303) Miscellaneous Intangible Plant	5,288,911	3,326,502
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	144,048,048	3,568,844
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,644,205	
9	(311) Structures and Improvements	113,671,044	294,783
10	(312) Boiler Plant Equipment	277,961,777	1,969,559
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	257,380,332	253,389
13	(315) Accessory Electric Equipment	52,625,551	
14	(316) Misc. Power Plant Equipment	28,348,904	
15	(317) Asset Retirement Costs for Steam Production	96,102,035	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	834,733,848	2,517,731
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	22,726,561	
19	(321) Structures and Improvements	1,089,255,000	8,005,040
20	(322) Reactor Plant Equipment	3,578,306,175	40,513,370
21	(323) Turbogenerator Units	1,174,748,789	69,674,379
22	(324) Accessory Electric Equipment	867,891,999	328,884
23	(325) Misc. Power Plant Equipment	1,163,407,580	19,670,017
24	(326) Asset Retirement Costs for Nuclear Production	3,364,966,683	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	11,261,302,787	138,191,690
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	42,702,784	1,494,917
28	(331) Structures and Improvements	525,711,868	11,258,977
29	(332) Reservoirs, Dams, and Waterways	2,123,274,585	23,134,792
30	(333) Water Wheels, Turbines, and Generators	1,011,720,934	45,455,861
31	(334) Accessory Electric Equipment	296,116,347	18,790,661
32	(335) Misc. Power PLant Equipment	102,422,330	19,720,410
33	(336) Roads, Railroads, and Bridges	93,136,325	4,824,618
34	(337) Asset Retirement Costs for Hydraulic Production	7,200,427	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	4,202,285,600	124,680,236
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,207,870	
38	(341) Structures and Improvements	210,804,448	208,588
39	(342) Fuel Holders, Products, and Accessories	11,271,196	202,263
40	(343) Prime Movers	227,881,069	99,250
41	(344) Generators	353,878,262	
42	(345) Accessory Electric Equipment	213,714,674	691,404
43	(346) Misc. Power Plant Equipment	98,646,013	262,734
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,135,403,532	1,464,239
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	17,433,725,767	266,853,896

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
			139,001,479		3
1,472,634			7,142,779		4
1,472,634			146,144,258		5
					6
					7
			8,644,205		8
			113,965,827		9
			279,931,336		10
					11
			257,633,721		12
			52,625,551		13
			28,348,904		14
			96,102,035		15
			837,251,579		16
					17
			22,726,561		18
5,196,267			1,092,063,773		19
22,022,776			3,596,796,769		20
33,253,668			1,211,169,500		21
501,761			867,719,122		22
11,796,664			1,171,280,933		23
			3,364,966,683		24
72,771,136			11,326,723,341		25
					26
142,633			44,055,068		27
331,059			536,639,786		28
4,953,895			2,141,455,482		29
6,591,938			1,050,584,857		30
4,587,875			310,319,133		31
2,877,607			119,265,133		32
			97,960,943		33
			7,200,427		34
19,485,007			4,307,480,829		35
					36
			19,207,870		37
			211,013,036		38
			11,473,459		39
			227,980,319		40
			353,878,262		41
			214,406,078		42
			98,908,747		43
					44
			1,136,867,771		45
92,256,143			17,608,323,520		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	277,291,080	2,805,453
49	(352) Structures and Improvements	496,058,041	-2,586,898
50	(353) Station Equipment	6,609,670,022	408,237,686
51	(354) Towers and Fixtures	961,833,447	31,816,054
52	(355) Poles and Fixtures	1,381,634,403	295,027,141
53	(356) Overhead Conductors and Devices	1,713,061,175	288,517,461
54	(357) Underground Conduit	511,176,139	1,625,123
55	(358) Underground Conductors and Devices	274,019,991	2,572,715
56	(359) Roads and Trails	94,354,165	12,868,187
57	(359.1) Asset Retirement Costs for Transmission Plant	1,634,335	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	12,320,732,798	1,040,882,922
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	180,650,839	470,638
61	(361) Structures and Improvements	322,849,256	820,941
62	(362) Station Equipment	3,512,564,041	232,948,775
63	(363) Storage Battery Equipment	33,497,273	235,777
64	(364) Poles, Towers, and Fixtures	4,832,728,954	573,759,773
65	(365) Overhead Conductors and Devices	4,799,825,748	404,595,341
66	(366) Underground Conduit	3,003,552,487	129,707,699
67	(367) Underground Conductors and Devices	4,806,619,874	246,720,013
68	(368) Line Transformers	3,790,727,265	358,712,581
69	(369) Services	3,422,179,773	174,510,460
70	(370) Meters	1,201,280,557	75,545,313
71	(371) Installations on Customer Premises	28,070,602	1,243,346
72	(372) Leased Property on Customer Premises	895,448	
73	(373) Street Lighting and Signal Systems	254,736,382	9,560,491
74	(374) Asset Retirement Costs for Distribution Plant	6,292,839	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	30,196,471,338	2,208,831,148
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	11,777,135	905,951
88	(391) Office Furniture and Equipment	15,430,221	173,393
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	145,357,613	11,412,544
92	(395) Laboratory Equipment	15,906,509	
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	368,250,696	70,038,426
95	(398) Miscellaneous Equipment	87,100,583	70,535,582
96	SUBTOTAL (Enter Total of lines 86 thru 95)	644,247,389	153,065,896
97	(399) Other Tangible Property	468,499,422	
98	(399.1) Asset Retirement Costs for General Plant	7,538,322	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,120,285,133	153,065,896
100	TOTAL (Accounts 101 and 106)	61,215,263,084	3,673,202,706
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)	-5,412	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	61,215,268,496	3,673,202,706

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
-275,667		515	280,372,715		48
		169,884	493,641,027		49
47,271,624			6,970,636,084		50
216,376			993,433,125		51
10,091,167			1,666,570,377		52
18,051,772			1,983,526,864		53
			512,801,262		54
			276,592,706		55
			107,222,352		56
	2,122,344		3,756,679		57
75,355,272	2,122,344	170,399	13,288,553,191		58
					59
			181,121,477		60
-47,225			323,717,422		61
35,008,627		-169,884	3,710,334,305		62
2,086,119			31,646,931		63
19,443,928		-515	5,387,044,284		64
78,638,576			5,125,782,513		65
170,189			3,133,089,997		66
10,173,383			5,043,166,504		67
38,387,422			4,111,052,424		68
4,696,605			3,591,993,628		69
27,221,773			1,249,604,097		70
			29,313,948		71
			895,448		72
93,256			264,203,617		73
	8,682,060		14,974,899		74
215,872,653	8,682,060	-170,399	32,197,941,494		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			424,632		86
			12,683,086		87
324,751			15,278,863		88
					89
					90
			156,770,157		91
204,306		-3,599,727	12,102,476		92
					93
287,828		3,599,727	441,601,021		94
565,853			157,070,312		95
1,382,738			795,930,547		96
			468,499,422		97
	-649,484		6,888,838		98
1,382,738	-649,484		1,271,318,807		99
386,339,440	10,154,920		64,512,281,270		100
					101
			-5,412		102
					103
386,339,440	10,154,920		64,512,286,682		104

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

Negative additions are attributed to work orders being reclassified to detailed plant accounts.

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

Electric Plant In Service does not include ASC 842 Operating Leases.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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					
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					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	03/25/2020	End of 2019/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	74001039 SAN FRAN Y (LARKIN): REPLACE 12KV SWGR	61,420,458
2	74029200 GATES BK 12 500/230KV TRANSFORMER	41,464,151
3	7054908 MC-P Relic- Project Management	40,914,287
4	74024721 FULTON-CALISTOGA 60 KV LREC 12 MI	28,654,123
5	74001857 EL CERRITO G: 115KV BUS UPGRADE PHASE 1	25,050,292
6	7070913 DS conduct Rel studies	24,974,659
7	74007941 CALTRAIN INTERCONNECTIONS SUB SITE 3	24,545,784
8	74003442 MOSS LANDING: REPLACE 500 KV BREAKERS	23,097,220
9	74001396 60-SOUTH OF PALERMO REINFORCEMENT (PH-2)	22,872,774
10	7096145 Q779 WRIGHT BUY BACK 2	22,426,305
11	74001710 SANGER: REPLACE 115 KV BUS	22,182,105
12	74000343 CALTRAIN INTERCONNECTIONS SUB SITE 1	22,108,591
13	74003358 PIT PH 1: ADD BK 5	20,817,627
14	74002462 PEASE - 115KV BUS TO BAAH RECONFIG	19,585,762
15	74001391 60-SOUTH OF PALERMO REINFORCEMENT (PH-1)	19,371,436
16	7021725 UNFFR Relic Routine Project Management	17,532,801
17	74000924 ESTRELLA_CPUC LIC/PER	17,400,560
18	74001953 SAN FRAN F (MARINA): REPLACE 4KV SWGR	16,745,453
19	74001436 (DA-B&M) ELECTRA-VALLEY SPRGS CAP/RECOND	16,147,350
20	74001098 TABLE MOUNTAIN: REPLACE 500 KV BK 1	16,022,726
21	74002346 MARYSVILLE SUB: CONVERT TO RING BUS	15,929,305
22	74025800 ELKHORN: INSTALL ENERGY STORAGE SYSTEM	15,266,943
23	74001858 EL CERRITO G: REPL 12KV CBS W/SWGR	14,179,799
24	74000925 MIDWAY ANDREW_CPUC LIC/PER	14,024,624
25	7026033 UNFFR Relic Aquatic Resource Stdy	13,637,366
26	68053001 COM: Integrated Video Mgt System Upgrade	13,582,130
27	74001780 RIO OSO: INSTALL 230KV BAAH/GIS	13,283,536
28	13004820 Drum Spaulding - Developing PAD and NOI	12,769,944
29	74000939 WRJ NONCOMPETITIVE_CPUC LIC/PER	12,309,654
30	74011380 74011380_GREATER BAY ER STORAGE FAC SF	12,177,367
31	74009501 Tiger Crk Abay LLO Gate Replace	12,160,355
32	74008580 ASHLAN: CONVERT TO 230 KV RING BUS	12,067,456
33	74006580 NV_TESLA 230KV BUS DIFFERENTIAL REPLACE	11,859,307
34	74000901 MARTIN BUS EXTENSION_CPUC LIC/PER	11,337,380
35	35120949 CWSP- BUCOCAMP - SKYWAY PARADISE TIE PH2	11,333,332
36	74001782 RIO OSO: INSTALL 115 KV BAAH/GIS	11,329,307
37	74016300 NETWORK SCADA Y-1	11,288,178
38	74000981 HERNDON SUB - NORTHERN FRESNO 115KV AREA	10,758,384
39	74003484 WILSON: INSTALL STATCOM	10,263,724
40	74011616 Helms - Rewind U2	10,148,890
41	74010362 PILOT: SAN BRUNO INT PIPE-TYPE UG CABLE	9,873,622
42	74000933 230 KV TLINE LOCKEFORD - NEW INDUSTRIAL	9,751,383
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	74001960 MOSS LANDING: INST 500 KV CTRL BUILDING	9,669,470
2	74010530 74010530 GREATER BAY ER STORAGE FAC OAK	9,396,893
3	74001785 RIO OSO: INSTALL 230 KV MPAC	9,331,806
4	74009504 SF M SUB, REPLACE BK 1 12KV & 4KV SWGR	9,264,278
5	74001708 SANGER: INSTALL 115 KV MPAC	9,141,492
6	68017320 COM: Replacement Oily Water Separator Sy	9,071,349
7	74001723 PEASE - INST BANK 5	9,014,030
8	74008620 Fordyce Dam Leakage Reduction	8,846,585
9	74006361 DELEVAN: INSTALL 200 MVAR SHUNT REACTOR	8,780,570
10	74000714 (DA-CE) COLGATE-CHALLENGE RELIABILITY	8,699,216
11	13003982 DS-C Relic- Cond studies for all RA	8,517,659
12	74001432 COTTNWD-RED BLUFF - RECONDUCTOR	8,469,063
13	74007808 RICE SUB: REPLACE BANK 1	8,418,610
14	74005121 EVERGREEN SUB: 115KV BUS UPGRADE	8,210,938
15	74001786 RIO OSO: INSTALL 115 KV MPAC	8,204,228
16	74017860 GEYSERS 12-FULTON RECOND 230KV	8,157,397
17	7076869 Buck Rel Studies	8,005,072
18	74001943 WHEELER RIDGE VOLTAGE SUPPORT (SUB)	7,943,559
19	74013564 INSTALL AIRWAYS 1104 & 1107	7,934,205
20	74010750 MONTA VISTA: INSTALL 230KV MPAC	7,893,591
21	74018760 ROUGH & READY TAP 60KV: CAPACITY INCREAS	7,838,355
22	74001713 HUNTERS POINT: 115KV GIS BAAH	7,112,028
23	31459454 IGNACIO SOBRANTE RPLC BOARDWALK TWR 16/	7,069,337
24	74001366 CORCORAN SMYRNA 115KV NERC ALERT PROJECT	6,969,438
25	74001781 RIO OSO: INSTALL BK 1 AND BK 2	6,939,177
26	74003450 CASCADE: INSTALL MPAC	6,714,550
27	7026032 UNFFR Relic Water Use & Qlty Stdy	6,546,770
28	74001454 Pit 1 LLO Gate Rplc & Radial Gate Seals	6,454,009
29	74021963 CWSP - OAKLAND K 1102 OCB ZONE	6,359,343
30	74018121 HERNDON-MANCHESTER 115KV OPGW	6,343,857
31	7026037 UNFFR Relic Land Use/Mgt Study	6,270,724
32	7055646 DS Relic- Project Management	6,252,337
33	74014700 Pit 6 U1 Replace Transformer	6,080,572
34	74005020 MIDWAY: UPGRADE 230 KV BUS SECTION D	6,066,981
35	7055507 DS Relic- Strategic Planning	6,061,004
36	74020987 ROUND MOUNTAIN: EM REP MOAS 821,823,825,	5,830,913
37	74003441 ASHLAN: INSTALL MPAC BUILDING & OPGW	5,828,977
38	74004825 HICKS: IMPROVE 230 KV BUS RELIABILITY	5,767,249
39	74001642 R1 MIDDLEFIELD ROAD REDWOOD CITY R20A	5,666,919
40	74001853 EL CERRITO G:REPLBK4 W/BK3 115-12KV 60MV	5,574,508
41	74015245 TSRP-NORTH BAY SIERRA ET COMM- READY SUB	5,428,757
42	7089447 Potter Valley Rel Studies	5,408,473
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 03/25/2020	End of 2019/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	74010581 ALMOND ST PARADISE R20A	5,384,911
2	74004508 LAKEWOOD SUB: REPLACE BANK 5	5,352,846
3	74004617 GEYSERS #9-LAKEVILLE NERC PROJECT	5,340,275
4	74000601 FULTON-FITCH: RECONDUCTORING 60 KV	5,301,791
5	74002206 GLENN: REPLACE BK 1	5,097,475
6	74021760 MIDWAY SUB: INSTALL 230kV MPAC	4,910,619
7	74005663 KERN PP: CONVERT 115KV BUS TO BAAH	4,906,029
8	74015247 TSRP-NORTH BAY SIERRA ET NEW COMM SYSTEM	4,894,212
9	74001558 EP LOBO AVE MERCED COUNTY R20A	4,858,410
10	74003069 LOS ESTEROS SHUNT REACTOR PROJECT	4,844,175
11	74004888 OAKLAND D SUB: REPLACE 4KV SWITCHGEAR	4,837,885
12	74002965 OAKLAND X: UPGD 115KV DIFF EDRS#: 201	4,789,940
13	7094147 Logical Access Management ODN	4,740,636
14	74009588 Pit 7 U2 Rewind	4,726,167
15	74015260 CASCADE: INSTALL BK 2 PHASE 1	4,677,750
16	74000709 (DA-TRC) HUMBOLDT BAY RECOND. PROJ. 2021	4,618,265
17	74004826 67-HICKS: INSTALL 230KV MPAC (CONSTR 201	4,571,040
18	68015242 PLO-COM::Rplc Secondary Chem Lab	4,557,732
19	74022382 CWSP-COLUMBIA HILL 1101-LR 2212 PH1	4,542,863
20	7089887 Kerckhoff Rel Studies	4,496,758
21	74002486 KERN PP: INSTALL 115KV MPAC BLDGS	4,368,345
22	68019301 U1:Upgrade Polisher Computer Workstation	4,314,159
23	74019563 SARATOGA SUB: RPLC TXFR BK1 EMER	4,231,670
24	74006664 RICE: EM REPLACE UNIT SUB 2	4,205,415
25	74006762 METCALF-SALINAS NO. 1 (IDLE) (P3)	4,196,721
26	74001175 MOSHER-LOCKFORD 60KV RECOND.	4,047,848
27	31187481 BRIDGEVILLE-GARBERVILLE:LAND ACQUISITION	4,017,178
28	74008281 Bucks Cr PH Repl U2 Turb Brg / Shaft	4,003,040
29	74000549 SF H (MARTIN): REPLACE 230/115KV BANK 7	3,937,870
30	74001433 (ENG) COTTNWD-RED BLUFF INSTALL TSP'S	3,844,124
31	74000731 EAST SHORE-OAKLAND J 115KV RECONDUCT(TL)	3,802,046
32	74001200 EXCHEQUER SUB TO BEAR VALLEY SUB	3,722,791
33	74001557 HESPERIAN BLVD ALAMEDA CNTY R20A	3,714,628
34	74000825 LEMOORE NAS 70 KV SCADA SW#55,65	3,713,882
35	7094991 CWSP - Wind Loading Project	3,648,418
36	74001688 NC_(DA-ABB) MAPLE CREEK SUB:REACTIVE SUP	3,565,166
37	74001707 SANGER SUB EXPANSION TLINE RELOCATION	3,540,095
38	74021027 METCALF-GREEN VALLEY 115KV: LINE RECONDU	3,539,468
39	74009957 IGNACIO SUB: PHYSICAL SECURITY UPGRADE	3,486,216
40	35098578 CWSP-COLUMBIA HILL 1101-LR 2212 PH2	3,466,397
41	7026034 UNFFR Relic Terres Resources Stdy	3,448,576
42	74019880 GUALALA: EMG REPLACE BK 2	3,418,567
43	TOTAL	2,102,914,386

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	74010249 CONTRA COSTA: REPLACE BANK 4	3,412,783
2	74006763 METCALF-SALINAS NO. 2	3,373,282
3	68045781 PLO-COM: REPL PAC 0-1 thru 0-7	3,348,813
4	74003264 Caribou 1 U1 Repl Runners, Bearing&Shaft	3,342,166
5	74002214 HOPLAND: REPLACE BK 2	3,334,213
6	13006140 MC-P Relic- Conduct Relicensing Studies	3,288,924
7	7049829 DC Relic Begin Prep of NOI and PAD	3,253,857
8	74008301 Lower Bucks Dam Install Upstream Liner	3,251,418
9	74021024 MORGAN HILL SUB: 115KV BAAH CONVERSION	3,213,940
10	74001856 EL CERRITO G: 115KV BUS UPGRADE PHASE 2	3,213,497
11	35109543 CWSP-EL DORADO 2101-19752- PHASE 1.5	3,211,225
12	74000915 KERN 230KV AREA REIN MIDWAY-KERN 3 & 4 (	3,208,748
13	74008009 WILSON-LEGRAND 115KV LINE RECON TL - DO	3,203,413
14	74008421 Bucks Cr Modify 2 Cranes	3,186,270
15	74009942 COTTONWOOD SUB: PHYSICAL SECURITY UPGRAD	3,183,546
16	30748101 R7 EP ED WRO - HWY 29 - KELSEYVILLE	3,173,439
17	68019124 PLO-Com:Repl Breathing Air Compsr Ph II	3,137,580
18	35110444 CWSP-VOLTA 1102-LR 1648-PH3.4	3,086,471
19	7054909 MC-P Relic- Prepare NOI and PAD	3,071,983
20	35109550 CWSP - EL DORADO 2101 - 19752 -PHASE 3.3	3,059,101
21	74024705 C1106 NETWORK PRIMARY CABLE REPLAC-OAKLA	3,032,464
22	74001766 RAVENSWOOD-COOLEY LANDING 115 KV (TL)	3,031,894
23	13008740 Battle Crk - Phase 2 License Amendment	3,017,126
24	74007501 SPENCE BANK 1 DIST LINE WORK	3,007,626
25	74015249 TSRP-NORTH BAY SIERRA ET MPAC/HMI SUBSTA	2,994,404
26	74021440 TSRP NS - IT OTHER SITES	2,972,908
27	7092705 Asset Data Improvement (Phase ID)	2,968,921
28	7053945 DC Relic - Prepare Study Plans	2,939,134
29	74014522 ORO LOMA: UPGRADE 70 KV BUS	2,938,823
30	74007381 Poe Tunnel Liner Improvements	2,917,310
31	74000345 CHSR INTERCONNECTIONS SUB SITES 4-7	2,913,889
32	74001739 (CONT.EST) MAPLE CREEK-WILLOW 60KV REL.	2,905,262
33	74004303 EP MOSS LANDING RD MOSS LANDING R20A	2,898,744
34	7076872 Buck Rel Lic App	2,886,201
35	74001732 VIERRA 115 KV REINFORCEMENT (T-LINE)	2,882,174
36	13011921 NFSL Additional Design Imp	2,879,492
37	35055695 OCEANO 1108 FEEDER EXT-EV STATIONS,PIS	2,878,353
38	74015486 ESTRELLA CPUC DATA REQUEST #3	2,854,991
39	74000936 WRJ COMPETITIVE_CPUC LIC/PER	2,850,638
40	74001584 STOCKTON A: REPLACE CONTROL BUILDING	2,823,052
41	35066745 BIG BEND 1102 - BLOOMER HILL 08W PHS 2	2,822,610
42	35109555 CWSP - EL DORADO 2101 - 19752 -PHASE 4.3	2,804,553
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	74022546 VGCC_IMPLEMENT EMS RTSRM	2,788,435
2	74021441 TSRP NS - ET NEW COMM - VSAT OR FAN	2,766,213
3	74022384 CWSP - FITCH MOUNTAIN 1113 LR 24918	2,755,416
4	68019302 PLO-U2:Cond. Polisher Cmptr Upgrade	2,753,955
5	7021727 UNFFR Relic Prepare 5 Year Library	2,751,557
6	74015248 TSRP NBS IT NEW MPLS	2,741,239
7	74012862 REP CARMEL BANK#2 WITH DIS TX	2,731,724
8	35109551 CWSP - EL DORADO 2101 - 19752 -PHASE 3.4	2,711,138
9	74001484 R5 2017 INSTALL RIO BRAVO 21KV FEEDER	2,703,049
10	74001802 PIT PH 1: REPLACE 230 KV BK 1	2,700,737
11	30854865 NEWARK-AMES 1300FT BW 46-50 CRITTENDON	2,698,325
12	74000341 CHSR INTERCONNECTIONS SUB SITES 8-13	2,695,878
13	7043247 RCC Lic Imp Cold Water Feasibility Study	2,687,809
14	74001047 KERN 230KV AREA REIN MIDWAY-KERN 1 & 2 (	2,663,393
15	74001334 TEMBLOR-SAN LUIS OBISPO 115KV NERC	2,660,560
16	7094925 CWSP - Line Sensor Pilot	2,616,300
17	74004802 CONTRA COSTA: UPGRADE 115KV BUS DIFF	2,605,435
18	74016341 TSRP NBS IT OTHER SITES	2,601,258
19	74000622 BELLOTA - WARNERVILLE RECONDUCTOR	2,592,679
20	74021861 MIDWAY: EM REPLACE BK 7 (115/12KV)	2,590,277
21	74000900 Bucks Creek U2 Generator Rewind	2,563,072
22	68021224 PLO- U1:Replace AFW Chem Inj Pmp	2,554,708
23	68038260 PLO-COM: North Access Rd Upgrade	2,537,124
24	7093505 08W - WILDFIRE RESILIENCY PMO	2,531,292
25	74004443 PITTSBURG: REPLACE CB 352 362	2,530,316
26	35109553 CWSP - EL DORADO 2101 - 19752 -PHASE 3.6	2,527,340
27	35110377 BR-03-10 (E) SHAY LN PARB	2,526,847
28	74015527 STOCKDALE- BAKERSFIELD SC OPGW	2,504,403
29	74002410 Pit 5 TGB Install Inline Oil Filtration	2,503,506
30	7026036 UNFFR Relic Rec Resources Study	2,499,282
31	74007783 Caribou 1 U2 Repl Runners, Bearing&Shaft	2,481,790
32	74017519 VACA DIXON: INSTALL 230 KV SMART WIRES	2,473,225
33	68021225 PLO- U2: Replace AFW Chem Inj Pmp	2,471,278
34	74011488 VALLEYSPRINGS-MARTELL NO.2 SCADA	2,468,436
35	74013480 KERN 230KV BAAH PHASE 2	2,460,334
36	13002402 DS-C Relic- Conduct Pre-App Proj Man	2,446,314
37	68036981 PLO: COM: 500kv Road Upgrade	2,431,255
38	74015251 TSRP-NORTH BAY SIERRA ET T-LINE SWITCHES	2,427,689
39	74018123 SF H (MARTIN)-REPL SHUNT REACTOR HZ2	2,391,518
40	74010660 Balch 2 - U2 Replace Cooling Water	2,387,468
41	74000707 60 KINGSBURG-LEMOORE 70KV RECOND. PH1	2,378,865
42	68048860 PLO - U1: Repl Plant Recorders 1R22	2,367,970
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	35109549 CWSP - EL DORADO 2101 - 19752 -PHASE 3.2	2,355,295
2	74006884 MORRO BAY SUB: UPGRADE 230KV BUS	2,345,835
3	7087874 Permit Holdover Project - Shasta-Trinity	2,300,857
4	74005120 EVERGREEN: UPGRADE 60 KV PROTECTION	2,265,647
5	74005355 RIO OSO SUB: SVC	2,260,723
6	31375536 ETTM MERCED ESTATES MOBILE HOME PARK	2,234,259
7	74011033 METCALF: EM REPL DIFF CABINET BUS 2 SEC	2,232,853
8	74009061 WESTPARK: INSTALL MPAC BUILDING	2,230,231
9	74008384 Battle Cr Salmon/Steelhead Phase 2	2,226,629
10	74008456 Cresta PH Repl Stoplog Hoist	2,165,426
11	74011030 KERN 230KV BAAH 115KV LINE RELOCATION	2,161,248
12	35110440 CWSP-VOLTA 1102-LR 1648-PH2.5	2,146,546
13	35064793 LP RECONDUCTOR, CABRILLO 1104 S006CC102	2,134,764
14	74008512 Coleman Intk Siph 1 Instl Trash Rake	2,130,025
15	7089450 Phoenix Rel Studies	2,128,648
16	74012040 NICOLAUS-WILKINS SLOUGH 60KV LINE POLE	2,114,958
17	74001792 RED BLUFF-COLEMAN REINFORCEMENT	2,106,525
18	31144652 COMBIE RD PH3A AUBURN R20A	2,102,121
19	74003261 Caribou 1 U1 Rewind	2,085,852
20	7093365 CWSP - PIH Non Generation	2,078,990
21	35031512 MISSION X 1127 NEW FEEDER	2,075,730
22	7026029 UNFFR Relic Prep 1st Stage Consult Pkg	2,072,927
23	13009580 DeSabla Replace Governor	2,072,742
24	74008459 Poe U2 Governor Upgrade Controls	2,064,295
25	74003803 Q954 FIFTH STANDARD SOLAR (NU) GATES	2,057,356
26	74008383 Coleman Tailrace Barrier Trashrake	2,055,958
27	68044188 PLO: COM: Upgrd Bldg 104 Entire 5th Flr	2,027,477
28	35072146 RPL 17,500' 4AR TIER 3 SILVERADO 2105	2,008,443
29	35110447 CWSP-VOLTA 1102-LR 1648-PH4.4	2,002,385
30	74002248 NV_TESLA SUB: REPLACE MOBILE TXFR T-22-2	1,984,260
31	74001920 CASCADE: REPLACE 60 KV CB 42 52 62 72	1,982,115
32	74002165 GATES: REPL BK 3 115/12 KV	1,960,133
33	74001735 POTRERO-MISSION #1 (A-X 1) SEISMIC RETRO	1,954,164
34	74010363 KERN PP-LIVE OAK 115KV LINE RECONDUCTOR	1,954,067
35	74001281 RESERVATION ROAD: REPL BK1	1,953,053
36	74000937 MERCY SPRINGS - CANAL SS T-LINE RECONDUC	1,946,538
37	74014400 ASHLAN: REROUTE 230KV T-LINES	1,946,216
38	31381600 ETTM CONCORD MCC	1,934,874
39	74010323 Poe PH Deck/Roof Resurface	1,934,022
40	74001485 EP BAILEY RD CONTRA COSTA CNTY R20A	1,932,287
41	35107688 CWSP - VOLTA 1102 - LR 1648 -PH1.1	1,923,808
42	74026000 LLAGAS: EM REPLACE BK1	1,918,888
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	74002161 NC_PENNGROVE 115/12KV BK 1	1,916,818
2	74016585 Caribou 1 U2 Generator Rewind	1,899,015
3	74017168 Pit 6 U2 Replace Transformer	1,883,245
4	7093249 ODN Logical Access Control	1,873,094
5	74016583 Electra U2 Generator Rewind	1,871,382
6	35105640 BR-03-01 (E) GATE LN PARB	1,862,178
7	74002977 SAN LEANDRO 115KV BUS DIFFERENTIAL	1,846,803
8	35085533 CWSP - SILVERADO 2104 - LR722 PH 1D	1,821,064
9	74014763 BUTTE REPL BK 2 AND CB1103	1,810,490
10	74011388 Q1127 LITTLE BEAR SOLAR 3 NU MENDOTA	1,803,524
11	74001733 POTRERO-LARKIN #2 (A-Y2) SEISMIC RETROFI	1,797,471
12	35103325 CWSP - MORAGA 1102 & 1104 - OCB	1,790,494
13	35109738 CWSP-VOLTA 1102-LR 1648-PH2.3	1,789,013
14	74002792 CANAL: REPLACE D-RTU ADD SCADA CB1200	1,784,389
15	31326189 CONTROL CENTER SYSTEM UPGRADE	1,779,202
16	31381605 ETTM BONAVENTURE PARK	1,779,156
17	74004890 PEASE - REPL BANK 2	1,775,168
18	74010504 FIGARDEN: REPL CB 252, 262 RELAYS	1,732,093
19	31306492 EMS Replacement Hardware	1,727,055
20	74009959 JEFFERSON SUB: PHYSICAL SECURITY UPGRADE	1,724,509
21	35110448 CWSP-VOLTA 1102-LR 1648-PH4.5	1,718,362
22	74000681 TERMINOUS: INSTALL D-SCADA 1102, 1103	1,716,227
23	74011223 OPAL CLIFF: REPLACE BK W/ 2 DIS STEPDOWN	1,715,600
24	7062249 MC-P- Proj Scoping and Study Plan Devp	1,714,868
25	7070917 DS Post App filing activities	1,713,542
26	35103324 CWSP - ROSSMOOR 1102 - OCB	1,696,104
27	74001397 (DA-TRC)ESSEX JCT ORICK 60KV RELIABILITY	1,696,041
28	35105644 BR-03-02 (E) ARANY CT PARB	1,691,386
29	74016340 TSRP NBS IT T-LINE SWITCHES	1,678,564
30	74019788 SHEPHERD 2111 AUBERRY RD RECON PH II	1,668,095
31	35106331 CWSP - VOLTA 1102 - LR 1648 - PH1.4	1,663,122
32	74007647 PEASE - TLINE SUPPORT	1,659,026
33	74023920 LIVERMORE: EM REP BK 1	1,650,412
34	74021201 GATES: REPL BK 3 TRANS BRKR & SW	1,633,597
35	74003501 SUMMIT: REPL 60 KV SW 37 & SW OPERATOR	1,633,015
36	35085536 CWSP - SILVERADO 2104 - LR722 PH 1G	1,630,537
37	7093170 Wildfire Wire Down detection	1,623,679
38	74016584 Tiger Creek U2 Generator Rewind	1,616,412
39	74000733 CARIBOU-BIG BEND 115KV NERC	1,602,693
40	74015280 ANTOINETTE LANE SOUTH SAN FRANCISCO R20A	1,601,348
41	7089886 Kerckhoff Rel PAD and NOI	1,591,012
42	74003102 Balch 2 U3 Repl Cooling Wtr Piping	1,568,451
43	TOTAL	2,102,914,386

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	74001734 MARTIN-LARKIN #1 115 KV CABLE (H-Y 1)	1,566,286
2	31381602 ETTM FRIENDLY VILLAGE	1,563,337
3	35110446 CWSP-VOLTA 1102-LR 1648-PH4.3	1,558,015
4	74001855 EL CERRITO G: 115KV BUS UPGRADE T-LINE	1,545,229
5	74003505 METCALF: UPGRADE ML 500 KV REMOTE END	1,544,713
6	74002827 OAKLAND L: INSTALL SCADA	1,542,320
7	7055645 DS Relic- Coord Study w/ NID	1,541,299
8	74001686 NC_MAPLE CREEK PROJ-BUS RECONFIGURATION	1,531,597
9	74009587 Pit 1 U1 Rewind Generator	1,514,393
10	74003661 Bucks Creek U1 Generator Stator Rewind	1,512,545
11	74008666 EL CERRITO G: INST 12KV FDR OUTLET, PH 1	1,507,125
12	31375538 ETTM NEW FRONTIER MHP	1,484,826
13	74019863 Butt Valley PH Standby Generator	1,481,128
14	74007800 Lake Valley Dam LLO Pipe Replace	1,477,712
15	68047884 PLO-U2:Repl Aux Transfrmr 2-1 Radiators	1,471,959
16	31155972 OSM EBOSS COFUNDING	1,468,868
17	13002403 DS-C Relic- Conduct Studies	1,465,011
18	7076873 Buck Rel 401 and CEQA	1,458,981
19	35112076 CWSP-FULTON 1107-OH TO UG MARK W SPG	1,456,906
20	35112249 BR-04-07 (E) CRESTMOOR PARB	1,449,342
21	35055474 OCGC REDBUD 1101 RECONDUCTOR FOR NB LOAD	1,445,803
22	74000975 METCALF - EVERGREEN RECONDUCTORING (TL)	1,438,899
23	68037720 PLO: U2 FAC 2R21	1,433,617
24	35130701 BR-04-01 (E) SUNSET DR PARB	1,418,926
25	7049828 DC Relic Project Management	1,394,967
26	35085538 SILVERADO 2105 WIRE DOWN - PH 1	1,392,040
27	74020946 PIT#1-COTTONWOOD 230KV INSULATORS	1,381,095
28	35085393 CWSP - SILVERADO 2104 - LR722 PH 1B	1,370,848
29	74004037 TESLA: REPLACE 500 KV SERIES SC BK 2	1,369,096
30	74018540 CASCADE - TLINE SUPPORT	1,368,585
31	35105647 BR-03-09 (E) MERRILL RD PARB	1,368,035
32	74011243 IGNACIO-MARE ISL 115KV (HWY SUB/COR SUB)	1,366,713
33	74010368 MEADOW LANE: REPLACE D-RTU	1,357,225
34	74001486 GRIZZLY PEAK BLVD BERKELEY R20A	1,355,360
35	74002824 MILPITAS: INSTALL D-SCADA 1100, 1200 & 2	1,355,286
36	13006781 DeSabla-Centerville Proj Mgmt Post LA	1,353,139
37	74001993 JARVIS: REPLACE BK2 WITH 45MVA BANK	1,349,467
38	74003600 Helms Replace Load Center 1, 2, 7 & 8	1,348,948
39	74009949 LAKEVILLE: PHYSICAL SECURITY UPGRADE	1,336,995
40	74001854 EL CERRITO G: REPL BANK 1	1,323,563
41	74008849 CYMRIC: INSTALL MRTU	1,313,825
42	74002227 NC_REPLACE BELLEVUE BANK 1	1,313,085
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	74010861 PIT PH#1 - 60KV - TLINE SUPPORT MALACHA	1,312,420
2	74015908 EMBARCADERO-POTRERO: UPGD SF RAS B AT VG	1,301,636
3	74021361 WOODLAND: EM INSTA CONTROL BUILDING	1,297,178
4	74004481 MESA 1104 FEEDER - PHASE 1	1,296,735
5	35085532 CWSP - SILVERADO 2104 - LR722 PH 1C	1,292,045
6	74021700 MIDWAY SUB: T-LINE WORK 230KV	1,290,182
7	31187482 GUALALA-MONTE RIO: LAND ACQUISITION	1,276,113
8	7089448 Phoenix Rel Project Management	1,275,362
9	74000665 BRIGHTON-GRAND ISLAND #1 & #2 115KV NERC	1,269,367
10	74009901 Rock Cr PH U1 & U2 Repl WG Seals	1,264,324
11	68040048 PLO: 2019 Capital Facility Improvements	1,253,407
12	74004970 SPRING GAP PH: INSTALL D-SCADA	1,253,100
13	74013601 PIT PH 1: REPLACE BK 3	1,252,613
14	74027520 IGNACIO: EM REP BK 1	1,244,618
15	74018545 HERDLYN 60KV RELAY PROJECT	1,243,587
16	74023521 TSRP NS - ET NEW COMM - MPAC/HMI SUBS	1,238,144
17	74025201 Pit 6 U1 Replace Gen Relays NERC	1,219,721
18	74003620 Cresta PH Repl Tailrace Gates	1,206,533
19	31234874 RELIAIBLITY 2017 - UWF VARIOUS CKTS	1,204,132
20	35111486 BR-04-03 (E) EDWARDS AND RIPLEY PARB	1,203,784
21	74003187 STAGG: INSTALL SPECIAL PROTECTION SCHEME	1,198,911
22	74003970 MONTEREY: INSTALL 3-D-BANKS & 60KV T BRK	1,197,532
23	74002196 VINA: INSTALL D-SCADA ON CB1101	1,191,717
24	68022580 PLO-COM:Replace LTCW Pumps	1,186,544
25	35085539 SILVERADO 2105 WIRE DOWN - PH 2	1,186,169
26	74014140 MONTA VISTA: UPGD SLAC RE RLY	1,185,715
27	7089885 Kerckhoff Rel Project Management	1,184,120
28	74003761 Rock Cr PH Repl Tailrace Gates	1,180,314
29	7076871 Buck Rel Draft Lic App	1,176,532
30	74017026 Helms - U2 Repl TSV	1,176,064
31	74008747 LOS BANOS-GATES #1 500KV LINE INS REPL	1,173,732
32	74007648 MONTA VISTA: UPGRADE 230 KV BUS PHASE 2	1,168,707
33	74010416 FRANKLIN SUB - REPLACE D-RTU	1,166,968
34	74007447 PANOCHE-ORO LOMA 115 KV LINE RECONDUCTOR	1,158,469
35	35129975 BR-03-11 (E) WHITAKER RD PARB	1,154,349
36	74011401 SMARTVILLE-MARYSVILLE 60KV RELO-LOMARICA	1,154,160
37	74009027 POTRERO: REPLACE SVC CONTROLLER	1,153,677
38	7090225 Test Floor Equip - TTS500	1,128,602
39	35053171 EXTEND EDENVALE 2105 FEEDER	1,122,273
40	74011242 IGNACIO-MARE ISL 115KV (IGN SUB/HWY SUB)	1,120,259
41	35117444 CWSP - VOLTA 1102 LR 1648 PH 2.1	1,115,304
42	68045340 PLO: COM:ACCESS RD COMMUNICATIONS	1,109,150
43	TOTAL	2,102,914,386

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	74010257 Scott Dam Replace Radial Gate Hoist	1,106,008
2	74010764 MESA-SANTA MARIA 115KV NERC	1,105,748
3	74007644 RAVENSWOOD-SAN MATEO 115KV PH2 NERC PROJ	1,097,249
4	31409528 ETTM THUNDERBIRD MOBILE ESTATES	1,080,162
5	74001332 KINGSBURG CORCORAN 1 AND 2 115KV NERC	1,077,330
6	7094734 2019 HBGS Catalyst Replacement	1,067,846
7	74003282 HUNTERS POINT: REPL 12KV BUS WITH SWGR	1,065,377
8	74000580 DRUM-RIO OSO #1-115KV IMPRV (STEEL)	1,061,684
9	74001435 (DA-B&M) ELECTRA TO WEST PT SCADA SWT.	1,060,776
10	74002140 CUYAMA: INSTALL T-SCADA	1,057,723
11	31274349 CAL WATER 1102 BACKTIE	1,056,965
12	74000842 SEMITROPIC: 115KV LINE RECOND	1,056,031
13	74013114 SAN LEANDRO U: BART RELAY PROJECT	1,049,604
14	74015250 TSRP NBS IT VSAT	1,042,661
15	74001271 MORAGA-OAKLAND #1&2 10200:10201 PH3 NERC	1,042,161
16	31260797 +R2Z OCEANO 1104 RECONDUCTORING BRANCH	1,040,426
17	74020340 Rock Cr PH U2 Repl TSV Seal and Bushings	1,026,346
18	74016063 EMBARCADERO-POTRERO SF RAS A AT SFGO	1,018,988
19	74010364 LIVE OAK-KERN OIL 115KV LINE RECONDUCTOR	1,017,015
20	74002400 Pit 4 Replace PSV Valve Controls	1,015,952
21	74010503 GREGG: REPL CB 552 RELAYS	1,015,038
22	35085537 CWSP - SILVERADO 2104 - LR722 PH 1H	1,005,802
23	74015503 AGED TWR REP PH1	1,000,333
24	See footnote for detail.	304,390,572
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	2,102,914,386

Schedule Page: 216.9 Line No.: 24 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	26,845,549,665	26,845,549,665		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	2,237,751,122	2,237,751,122		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Reverse Common Allocation	-154,022,583	-154,022,583		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	2,083,728,539	2,083,728,539		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	384,866,806	384,866,806		
13	Cost of Removal	320,801,138	320,801,138		
14	Salvage (Credit)	6,848,541	6,848,541		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	698,819,403	698,819,403		
16	Other Debit or Cr. Items (Describe, details in footnote):	68,512,850	68,512,850		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	28,298,971,651	28,298,971,651		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	330,575,368	330,575,368		
21	Nuclear Production	6,950,099,227	6,950,099,227		
22	Hydraulic Production-Conventional	1,442,868,656	1,442,868,656		
23	Hydraulic Production-Pumped Storage	785,514,655	785,514,655		
24	Other Production	377,022,525	377,022,525		
25	Transmission	3,346,594,295	3,346,594,295		
26	Distribution	14,441,006,615	14,441,006,615		
27	Regional Transmission and Market Operation				
28	General	625,290,310	625,290,310		
29	TOTAL (Enter Total of lines 20 thru 28)	28,298,971,651	28,298,971,651		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Eureka Energy Company			
2	Common Stock	1978		1,000
3	Additional Paid in Capital			3,734,531
4	Undistributed Earnings			-44,241
5				
6	SUBTOTAL			3,691,290
7				
8	Natural Gas Corporation of California			
9	Common Stock	1954		100,000
10	Additional Paid in Capital			3,037,432
11	Undistributed Earnings			-3,137,432
12				
13	SUBTOTAL			
14				
15	Pacific Energy Fuels Company			
16	Common Stock	1989		10,000
17	Additional Paid in Capital			4,890,952
18	Undistributed Earnings			-5,102,693
19				
20	SUBTOTAL			-201,741
21				
22	Standard Pacific Gas Line Incorporated			
23	Common Stock	1930-32		1,200
24	Additional Paid in Capital	1954		45,889,873
25	Undistributed Earnings			-28,055,130
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			42,154,119
35				
36	Midway Power LLC			
37	Additional Paid in Capital	2008		26,112,410
38	Undistributed Earnings			-21,673,733
39				
40	SUBTOTAL			4,438,677
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	50,082,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1,000		2
		3,727,170		3
-58,197		-102,438		4
				5
-58,197		3,625,732		6
				7
				8
		100,000		9
		3,037,432		10
		-3,137,432		11
				12
				13
				14
				15
		10,000		16
		4,890,952		17
-5,090		-5,604,573		18
				19
-5,090		-703,621		20
				21
				22
		1,200		23
		45,890,210		24
-12,256		-29,337,919		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
-12,256		40,871,667		34
				35
				36
		26,112,410		37
-16,114		-21,689,847		38
				39
-16,114		4,422,563		40
				41
-91,657		48,216,341		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	1,566,341	961,981	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)	370,586,376	460,127,152	ALL
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	22,861,186	23,061,195	ALL
8	Transmission Plant (Estimated)	19,698,339	26,047,165	ALL
9	Distribution Plant (Estimated)	29,514,511	40,380,237	ALL
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	442,660,412	549,615,749	
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)	444,226,753	550,577,730	

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

In 2019, PG&E changed the methodology of estimating Materials and Supplies costs for production plant (Estimated), Transmission Plant (Estimated), and Distribution Plant (Estimated) to align with PG&E's FERC rate case methodology. As such, the balances presented for the beginning of the year have been retrospectively adjusted. The 12/31/2018 Total Account 154 balance remains the same as what was reported in the prior year.

		12/31/2018 Balance as reported in 2018 FERC Form 1	12/31/2018 Balance as reported in 2019 FERC Form 1
5	Assigned to - Construction (Estimated)	118,788,016	370,586,376
6	Assigned to - Operations and Maintenance	0	0
7	Production Plant (Estimated)	122,909,574	22,861,186
8	Transmission Plant (Estimated)	42,589,220	19,698,339
9	Distribution Plant (Estimated)	158,373,602	29,514,511
10	Regional Transmission & Market Operation Plant (Estimated)	0	0
11	Assigned to - Other (provide details in footnote)	0	0
12	TOTAL Account 154 (lines 5 thru 11)	**442,660,412**	**442,660,412**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	143,687.00		13,860.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Allowances Used	12.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	143,675.00		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)		18		
45	Gains		18		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
13,860.00		13,860.00		360,360.00		545,627.00		1
								2
								3
				13,860.00		13,860.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
						12.00		20
								21
								22
								23
								24
								25
								26
								27
								28
13,860.00		13,860.00		374,220.00		559,475.00		29
								30
								31
								32
								33
								34
								35
199.00		199.00		9,751.00		10,547.00		36
				398.00		398.00		37
								38
				199.00		398.00		39
199.00		199.00		9,950.00		10,547.00		40
								41
								42
								43
					3		21	44
					3		21	45
								46

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

Beginning balance of account 158.1 per this page does not agree to the corresponding balance sheet line item on page 110. Difference is due to approximately $395,755,701 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately $430,000 in alternative fuel vehicle credits.

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

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line item on page 110. Difference is due to approximately $408,680,309 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately $430,000 in alternative fuel vehicle credits.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2021		2022		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 PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Santa Cruz 115kV Reinforcement	3,620,556	63,333			3,557,222
22	10/4/2016 (03/2016 to 12/2075)					
23						
24	Atlantic-Placer 115kV	324,906				324,906
25	Transmission Line Project					
26	10/1/2019 (1/1/2020 to 12/31/2020					
27						
28	Mesa (Diablo Canyon Voltage	1,110,344				1,110,344
29	Support Project)					
30	10/1/2019 (1/1/2020 to 12/31/2020					
31						
32	DCPP License Renewal Cost	14,353,057	2,050,437			12,302,620
33	1/1/2018 (01/2018 to 12/2025)					
34						
35	DCPP Canceled Projects	51,295,864				51,295,864
36	1/1/2018 (Pending 2020 GRC)					
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	70,704,727	2,113,770			68,590,956

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	(See details in foot notes)	2,988,831	186	(2,682,509)	186
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	(See details in foot notes)	949,440	186	(1,889,807)	186
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 2 Column: a

Order	Order Description	Balance 12/31/2018	Costs Incurred	Reimbursements Received	Balance 12/31/2019
9715072	WL -(SIS)Interconnection Merced Irr Dist	(500.00)	500.00		
9719582	WG Gradient Resources Project SIS	22,883.99	(22,883.99)		
9719800	WAPA O'Neill Substation - System Impact	4,623.39			4,623.39
9719900	WG - BURNS&MCDONNELL-Cluster work	5,517.59			5,517.59
9722202	WG - C6 - Cluster 6 Phase 2	24,433.62	(24,433.62)		
9724040	KMPUD Load Interconnection Study	(11,807.00)	11,807.00		
9724300	Ntwrk Eval for Calpine 115kV Geysers Gen	(10,369.32)			(10,369.32)
9725002	WG - C8 - SM - Quail Creek Solar 1	127.91	(127.91)		
9725844	CDWR BDCP Phase 2 sudy	703.14	(703.14)		
9726740	WG - 2016 Reassessment Gen Interconn	(0.68)	0.68		
9726940	WAPA - Cottonwood Olinda line work	106,088.91			106,088.91
9727720	SFPUC - Potrero Interconnection	179.06	(179.06)		
9727980	LBNL Capacity Increase	4,653.80	(4,653.80)		
9728340	SVP Breaker Replacement	(8,863.39)			(8,863.39)
9728360	Travis AFB Facility Study	(64,155.75)			(64,155.75)
9728526	Port of Stockton Load Increase	(21,889.59)			(21,889.59)
9728645	WG # MMA # Q720&Q1002	(0.02)	0.02		
9729040	2016 Merced ID Load Interconnection Faci	(39,007.50)		39,007.50	
9729280	LBNL Interconnection Capacity Increase	(0.31)	0.31		
9729340	WG - 2017 Reassessment	0.22	(0.22)		
9729546	WAPA SLTP	3,043.50			3,043.50
9729703	WG - C9P2 - Cluster 9 Phase 2	(13.21)	13.21		
9729761	Port of Stockton FAS	(40,364.18)			(40,364.18)
9729808	WG - Cluster IR Review/SM for Protection	5,158.41	(5,158.41)		
9729841	WG - C10P1 - Cluster 10 Phase 1	(0.01)	0.01		
9729845	WG - C10 - SM - Project01	(104.94)	104.94		
9729846	WG - C10 - SM - Project02	(127.98)	127.98		
9729847	WG - C10 - SM - Project03	(128.64)	128.64		
9729848	WG - C10 - SM - Project04	(242.05)	242.05		
9729849	WG - C10 - SM - Project05	(155.86)	155.86		
9729850	WG - C10 - SM - Project06	(257.93)	257.93		
9729851	WG - C10 - SM - Project07	(197.01)	197.01		
9729852	WG - C10 - SM - Project08	(247.86)	247.86		
9729853	WG - C10 - SM - Project09	(192.47)	192.47		
9729854	WG - C10 - SM - Project10	(237.51)	237.51		
9729855	WG - C10 - SM - Project11	5,426.86	(5,426.86)		
9729856	WG - C10 - SM - Project12	(134.78)	134.78		
9729857	WG - C10 - SM - Project13	(112.86)	112.86		
9729859	WG - C10 - SM - Project15	(186.00)	186.00		
9729881	WG - C10 - SM - Project17	(226.49)	226.49		
9729882	WG - C10 - SM - Project18	(145.56)	145.56		
9729883	WG - C10 - SM - Project19	(124.42)	124.42		
9729884	WG - C10 - SM - Project20	(237.94)	237.94		
9729885	WG - C10 - SM - Project21	(5,962.76)	5,962.76		
9729886	WG - C10 - SM - Project22	(170.12)	170.12		
9729887	WG - C10 - SM - Project23	(144.19)	144.19		
9729888	WG - C10 - SM - Project24	(133.48)	133.48		
9729889	WG - C10 - SM - Project25	(151.47)	151.47		
9729890	WG - C10 - SM - Project26	(249.28)	249.28		

9729891	WG - C10 - SM - Project27	(197.01)	197.01		
9729892	WG - C10 - SM - Project28	(271.86)	271.86		
9729893	WG - C10 - SM - Project29	(264.84)	264.84		
9729894	WG - C10 - SM - Project30	(112.09)	112.09		
9729895	WG - C10 - SM - Project31	(220.00)	220.00		
9729896	WG - C10 - SM - Project32	(220.33)	220.33		
9729897	WG - C10 - SM - Project33	(101.95)	101.95		
9729898	WG - C10 - SM - Project34	(79.06)	79.06		
9729899	WG - C10 - SM - Project35	(147.21)	147.21		
9729900	WG - C10 - SM - Project36	(269.40)	269.40		
9729901	WG - C10 - SM - Project37	(177.25)	177.25		
9729902	WG - C10 - SM - Project38	1,421.04	(1,421.04)		
9729903	WG - C10 - SM - Project39	(70.70)	70.70		
9729904	WG - C10 - SM - Project40	(163.29)	163.29		
9729905	WG - C10 - SM - Project41	(195.08)	195.08		
9729906	WG - C10 - SM - Project42	(122.16)	122.16		
9729907	WG - C10 - SM - Project43	(309.21)	309.21		
9729908	WG - C10 - SM - Project44	(163.08)	163.08		
9729909	WG - C10 - SM - Project45	(242.71)	242.71		
9729910	WG - C10 - SM - Project46	(292.32)	292.32		
9729911	WG - C10 - SM - Project47	(438.55)	438.55		
9729912	WG - C10 - SM - Project48	(339.34)	339.34		
9729913	WG - C10 - SM - Project49	(265.06)	265.06		
9729914	WG - C10 - SM - Project50	(79.39)	79.39		
9729960	WG - C10 - SM - Project51	(9.36)	9.36		
9729961	WG - C10 - SM - Project52	(134.78)	134.78		
9729962	WG - C10 - SM - Project53	(102.07)	102.07		
9729963	CAISO ISP Panoche	(260.85)	260.85		
9730243	SFPUC - Potrero Interconnection	2,399.24	3,303.39		5,702.63
9730681	WG - ISP - Porthos	1,680.00	(1,680.00)		
9730823	WAPA Lemoore NAS	19,766.82	13,579.11		33,345.93
9732360	WG # Cluster 11 Phase 1	742,359.93	682,414.81	(1,283,731.58)	141,043.16
9734582	WG – Quanta Technology DG Study Rule 21		(350.32)		(350.32)
9735100	WG – Cluster 11 Phase 2		727,321.90		727,321.90
9735241	Cluster 12 Phase 1		551,088.23		551,088.23
9707780	CP-Martin 115/60 kV Upgrade Project	1,722.47	322.79		2,045.26
9713955	WL - Tesla Tracy 230kV Line 1 Reloc-FAS	13,215.50			13,215.50
9722206	Trans Bay Cable Quick Start Study	5,264.21			5,264.21
9717187	WL - CA HiSpeed Train Interconnect Study	23,850.17			23,850.17
9714755	WL - KMPUD-IFAS	63,553.10	(63,553.10)		
9731302	Swan Lake Affected Sys. Study	82,245.31			82,245.31
9731780	WG - 2018 Reassessment	387,072.56	(0.06)	(387,072.50)	
9732200	WG # ISP-South Belridge Expansion	27,452.87			27,452.87
9732401	WG - C11 - SM - Project 01	(62.89)	62.89		
9732402	WG - C11 - SM - Project 02	(62.88)	62.88		
9732404	WG - C11 - SM - Project 04	1,937.19	(1,937.19)		
9732405	WG - C11 - SM - Project 05	(62.89)	62.89		
9732406	WG - C11 - SM - Project 06	(62.89)	62.89		
9732407	WG - C11 - SM - Project 07	(62.89)	62.89		
9732408	WG - C11 - SM - Project 08	(424.19)	424.19		
9732409	WG - C11 - SM - Project 09	(62.89)	62.89		
9732410	WG - C11 - SM - Project 10	(62.90)	62.90		
9732411	WG - C11 - SM - Project 11	612.14	(612.14)		
9732412	WG - C11 - SM - Project 12	1,937.11	(1,937.11)		

9732413	WG - C11 - SM - Project 13	(62.89)	62.89		
9732414	WG - C11 - SM - Project 14	(62.89)	62.89		
9732415	WG - C11 - SM - Project 15	(62.89)	62.89		
9732416	WG - C11 - SM - Project 16	(62.89)	62.89		
9732417	WG - C11 - SM - Project 17	(62.90)	62.90		
9732418	WG - C11 - SM - Project 18	(18.69)	18.69		
9732419	WG - C11 - SM - Project 19	(62.89)	62.89		
9732420	WG - C11 - SM - Project 20	(62.89)	62.89		
9732421	WG - C11 - SM - Project 21	(62.89)	62.89		
9732422	WG - C11 - SM - Project 22	(62.89)	62.89		
9732423	WG - C11 - SM - Project 23	(62.89)	62.89		
9732424	WG - C11 - SM - Project 24	(62.89)	62.89		
9732425	WG - C11 - SM - Project 25	1,937.11	(1,937.11)		
9732426	WG - C11 - SM - Project 26	(243.52)	243.52		
9732427	WG - C11 - SM - Project 27	(62.90)	62.90		
9732428	WG - C11 - SM - Project 28	(62.89)	62.89		
9732429	WG - C11 - SM - Project 29	(62.89)	62.89		
9732430	WG - C11 - SM - Project 30	(62.89)	62.89		
9732431	WG - C11 - SM - Project 31	(243.52)	243.52		
9732432	WG - C11 - SM - Project 32	(62.89)	62.89		
9732433	WG - C11 - SM - Project 33	(62.90)	62.90		
9732434	WG - C11 - SM - Project 34	(62.89)	62.89		
9732435	WG - C11 - SM - Project 35	(243.51)	243.51		
9732436	WG - C11 - SM - Project 36	(62.89)	62.89		
9732437	WG - C11 - SM - Project 37	(62.89)	62.89		
9732438	WG - C11 - SM - Project 38	(62.89)	62.89		
9732439	WG - C11 - SM - Project 39	(62.89)	62.89		
9732440	WG - C11 - SM - Project 40	(63.78)	63.78		
9732441	WG - C11 - SM - Project 41	696.41	(696.41)		
9732442	WG - C11 - SM - Project 42	(62.89)	62.89		
9732443	WG - C11 - SM - Project 43	(62.88)	62.88		
9732444	WG - C11 - SM - Project 44	(62.89)	62.89		
9732445	WG - C11 - SM - Project 45	1,937.11	(1,937.11)		
9732447	WG - C11 - SM - Project 47	150.41	(150.41)		
9732448	WG - C11 - SM - Project 48	937.11	(937.11)		
9732449	WG - C11 - SM - Project 49	(62.89)	62.89		
9732450	WG - C11 - SM - Project 50	(62.89)	62.89		
9732451	WG - C11 - SM - Project 51	(62.89)	62.89		
9732452	WG - C11 - SM - Project 52	(62.89)	62.89		
9732453	WG - C11 - SM - Project 53	(424.19)	424.19		
9732454	WG - C11 - SM - Project 54	(62.89)	62.89		
9732455	WG - C11 - SM - Project 55	(62.89)	62.89		
9732560	WG - C11 - SM - Project 100	(42.33)	42.33		
9732561	WG - C11 - SM - Project 56	(18.18)	18.18		
9732562	WG - C11 - SM - Project 57	(62.89)	62.89		
9732563	WG - C11 - SM - Project 58	(62.89)	62.89		
9732564	WG - C11 - SM - Project 59	(62.89)	62.89		
9732565	WG - C11 - SM - Project 60	897.10	(897.10)		
9732566	WG - C11 - SM - Project 61	(62.88)	62.88		
9732567	WG - C11 - SM - Project 62	(62.89)	62.89		
9732568	WG - C11 - SM - Project 63	(62.89)	62.89		
9732569	WG - C11 - SM - Project 64	2,000.00	(2,000.00)		
9732570	WG - C11 - SM - Project 65	(62.89)	62.89		
9732571	WG - C11 - SM - Project 66	(62.89)	62.89		

9732572	WG - C11 - SM - Project 67	(62.89)	62.89		
9732573	WG - C11 - SM - Project 68	(62.89)	62.89		
9732574	WG - C11 - SM - Project 69	696.41	(696.41)		
9732575	WG - C11 - SM - Project 70	(62.89)	62.89		
9732576	WG - C11 - SM - Project 71	(62.89)	62.89		
9732577	WG - C11 - SM - Project 72	1,937.11	(1,937.11)		
9732578	WG - C11 - SM - Project 73	(62.89)	62.89		
9732579	WG - C11 - SM - Project 74	(62.89)	62.89		
9732580	WG - C11 - SM - Project 75	(62.89)	62.89		
9732581	WG - C11 - SM - Project 76	143.54	(143.54)		
9732583	WG - C11 - SM - Project 78	(42.33)	42.33		
9732584	WG - C11 - SM - Project 79	(62.89)	62.89		
9732586	WG - C11 - SM - Project 81	765.81	(765.81)		
9732587	WG - C11 - SM - Project 82	(62.89)	62.89		
9732588	WG - C11 - SM - Project 83	(62.89)	62.89		
9732589	WG - C11 - SM - Project 84	(62.89)	62.89		
9732590	WG - C11 - SM - Project 85	(62.89)	62.89		
9732591	WG - C11 - SM - Project 86	(62.89)	62.89		
9732592	WG - C11 - SM - Project 87	(62.89)	62.89		
9732593	WG - C11 - SM - Project 88	1,937.11	(1,937.11)		
9732594	WG - C11 - SM - Project 89	(62.89)	62.89		
9732595	WG - C11 - SM - Project 90	(42.33)	42.33		
9732600	WG - C11 - SM - Project 95		35.24		35.24
9732681	WG # Cluster 10 Phase 2	559,394.02	33,241.44	(561,444.12)	31,191.34
9734103	WG – 2019 Reassessment and Downsizing St		391,303.27		391,303.27
9734243	WG – ISP Ceres Energy Storage		9,324.01		9,324.01
9734260	WG – ISP Kuiper Energy Storage		51,200.28		51,200.28
9734360	WG – ISP Riviera Solar		7,461.07		7,461.07
9734680	WG – ISP Camptonville Biopower 1		32,974.51		32,974.51
9734720	WG – ISP Dallas ES 3		44,187.40		44,187.40
9734721	WG – ISP Houston Storage		7,979.57	(7,979.57)	
9734722	WG – ISP Dallas ES 2		46,278.47		46,278.47
9734906	WG - C12 - SM - Project 01		5,581.09	(5,620.92)	(39.83)
9734907	WG - C12 - SM - Project 02		6,560.93	(6,600.76)	(39.83)
9734908	WG - C12 - SM - Project 03		6,971.77	(6,993.17)	(21.40)
9734909	WG - C12 - SM - Project 04		7,247.32	(7,267.02)	(19.70)
9734910	WG - C12 - SM - Project 05		5,827.50	(5,847.21)	(19.71)
9734911	WG - C12 - SM - Project 06		5,395.48	(5,415.18)	(19.70)
9734980	WG - C12 - SM - Project 07		9,849.09	(9,868.79)	(19.70)
9734981	WG - C12 - SM - Project 08		9,140.13	(9,169.28)	(29.15)
9734982	WG - C12 - SM - Project 09		7,043.37	(7,063.07)	(19.70)
9734983	WG - C12 - SM - Project 10		7,476.44	(7,496.13)	(19.69)
9734984	WG - C12 - SM - Project 11		7,099.77	(7,119.48)	(19.71)
9734985	WG - C12 - SM - Project 12		5,415.21	(5,434.90)	(19.69)
9734986	WG - C12 - SM - Project 13		6,368.18	(6,387.88)	(19.70)
9734987	WG - C12 - SM - Project 14		7,621.22	(7,681.22)	(60.00)
9734988	WG - C12 - SM - Project 15		5,247.13	(5,266.83)	(19.70)
9734989	WG - C12 - SM - Project 16		7,054.43	(7,077.24)	(22.81)
9735011	WG - C12 - SM - Project 17		4,685.40	(4,705.10)	(19.70)
9735012	WG - C12 - SM - Project 18		5,054.87	(5,074.57)	(19.70)
9735013	WG - C12 - SM - Project 19		5,016.30	(5,036.00)	(19.70)
9735014	WG - C12 - SM - Project 20		4,763.87	(4,783.58)	(19.71)
9735015	WG - C12 - SM - Project 21		5,264.82	(5,285.19)	(20.37)
9735016	WG - C12 - SM - Project 22		7,580.02	(7,599.72)	(19.70)

9735017	WG - C12 - SM - Project 23		4,871.46	(4,891.16)	(19.70)
9735018	WG - C12 - SM - Project 24		9,517.13	(9,556.96)	(39.83)
9735019	WG - C12 - SM - Project 25		7,376.63	(7,396.32)	(19.69)
9735020	WG - C12 - SM - Project 26		7,140.35	(7,160.06)	(19.71)
9735021	WG - C12 - SM - Project 27		4,349.76	(4,369.46)	(19.70)
9735022	WG - C12 - SM - Project 28		5,481.96	(5,501.65)	(19.69)
9735023	WG - C12 - SM - Project 29		6,022.25	(6,041.95)	(19.70)
9735024	WG - C12 - SM - Project 30		9,071.20	(9,090.90)	(19.70)
9735025	WG - C12 - SM - Project 31		7,687.49	(7,707.19)	(19.70)
9735026	WG - C12 - SM - Project 32		4,484.23	(4,503.94)	(19.71)
9735027	WG - C12 - SM - Project 33		4,788.87	(4,808.57)	(19.70)
9735028	WG - C12 - SM - Project 34		7,282.61	(7,302.31)	(19.70)
9735029	WG - C12 - SM - Project 35		8,753.88	(8,773.59)	(19.71)
9735030	WG - C12 - SM - Project 36		8,528.67	(7,631.70)	896.97
9735031	WG - C12 - SM - Project 37		2,742.39	(2,762.09)	(19.70)
9735032	WG - C12 - SM - Project 38		6,728.51	(6,748.22)	(19.71)
9735033	WG - C12 - SM - Project 39		6,427.96	(6,447.66)	(19.70)
9735034	WG - C12 - SM - Project 40		9,818.42	(9,838.12)	(19.70)
9735035	WG - C12 - SM - Project 41		6,361.28	(6,380.97)	(19.69)
9735140	WG - C12 - SM - Project 42		7,425.76	(7,445.45)	(19.69)
9735141	WG - C12 - SM - Project 43		4,905.03	(4,924.73)	(19.70)
9735142	WG - C12 - SM - Project 44		3,905.81	(3,925.51)	(19.70)
9735143	WG - C12 - SM - Project 45		4,445.57	(4,465.26)	(19.69)
9735144	WG - C12 - SM - Project 46		6,947.34	(6,967.04)	(19.70)
9735145	WG - C12 - SM - Project 47		5,035.06	(5,054.75)	(19.69)
9735146	WG - C12 - SM - Project 48		5,508.56	(5,528.26)	(19.70)
9735147	WG - C12 - SM - Project 49		6,146.33	(6,166.04)	(19.71)
9735148	WG - C12 - SM - Project 50		5,142.07	(5,161.38)	(19.31)
9735149	WG - C12 - SM - Project 51		12,038.13	(12,057.83)	(19.70)
9735150	WG - C12 - SM - Project 52		7,080.26	(7,099.95)	(19.69)
9735151	WG - C12 - SM - Project 53		9,699.60	(9,719.30)	(19.70)
9735152	WG - C12 - SM - Project 54		5,870.20	(5,889.90)	(19.70)
9735153	WG - C12 - SM - Project 55		7,620.27	(7,639.97)	(19.70)
9735154	WG - C12 - SM - Project 56		7,144.55	(7,164.26)	(19.71)
9735155	WG - C12 - SM - Project 57		6,255.35	(6,275.05)	(19.70)
9735156	WG - C12 - SM - Project 58		5,229.39	(5,249.09)	(19.70)
9735157	WG - C12 - SM - Project 59		6,029.53	(6,049.22)	(19.69)
9735158	WG - C12 - SM - Project 60		6,203.01	(6,222.71)	(19.70)
9735159	WG - C12 - SM - Project 61		6,278.45	(6,298.15)	(19.70)
9735160	WG - C12 - SM - Project 62		9,586.11	(9,625.94)	(39.83)
9735161	WG - C12 - SM - Project 63		5,399.90	(5,419.60)	(19.70)
9735162	WG - C12 - SM - Project 64		5,921.10	(5,940.79)	(19.69)
9735163	WG - C12 - SM - Project 65		7,789.39	(7,809.09)	(19.70)
9735164	WG - C12 - SM - Project 66		6,184.39	(6,204.09)	(19.70)
9735165	WG - C12 - SM - Project 67		5,691.64	(5,711.34)	(19.70)
9735166	WG - C12 - SM - Project 68		7,878.29	(7,897.99)	(19.70)
9735167	WG - C12 - SM - Project 69		6,458.42	(6,478.11)	(19.69)
9735168	WG - C12 - SM - Project 70		5,753.69	(5,773.39)	(19.70)
9735169	WG - C12 - SM - Project 71		5,609.21	(5,628.91)	(19.70)
9735170	WG - C12 - SM - Project 72		10,455.23	(10,474.93)	(19.70)
9735171	WG - C12 - SM - Project 73		2,920.10	(2,156.38)	763.72
9735172	WG - C12 - SM - Project 74		3,138.54	(3,158.23)	(19.69)
9735540	WG – Repower Diablo Canyon Repower		21,428.77		21,428.77
	Total Transmission	1,915,024.93	2,988,831.38	(2,682,508.97)	2,221,347.34

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 231 Line No.: 22 Column: a

Order	Order Description	Balance 12/31/2018	Costs Incurred	Reimbursements Received	Balance 12/31/2019
9725281	Estrella Substation - Facilities Study	(677.55)			(677.55)
9729522	R21Beldrige Wtr Stor 352165 NEM2 Det Sty	3,239.18			3,239.18
9729806	WDT - Chevron USA Prod Co ISP	(30,265.09)	27,559.77		(2,705.32)
9729921	Shiloh I Wind Project Facilities Study	20,236.55	18,269.53		38,506.08
9729923	Exchequer RAS - CAISO Post COD	4,296.03			4,296.03
9729980	MMA - Q1158 Slate - ISO 51731	5,800.23			5,800.23
9729981	MMA-Q1036 Mustang 2-Gen-Tie-ISO 51601	1,748.70		(1,748.70)	
9730060	MMA - QF Santa Clara Wind - 51155	13,450.64	8,635.42	(17,874.64)	4,211.42
9730061	MMA - Q1096 & QF Altamont Midway - 51156	12,446.98	25,492.66		37,939.64
9730062	MMA - QF Forebay Wind - 51154	14,902.71	5,915.23	(19,252.52)	1,565.42
9730065	Q877 California Flats - Roadway PEIE	(516,579.91)	36,434.10		(480,145.81)
9730242	MMA - Q653F SP PVUSA - BESS-ISO 60192-C	3,385.53	3,557.98	(6,943.51)	
9730360	Kingsburg Cogen - Facility Study	1,493.72			1,493.72
9730420	1469-RD BELRIDGE WATER/Detailed	(8,236.82)			(8,236.82)
9730660	WDT - CA-17-0097 SB43 Arco - ISP	1,226.45			1,226.45
9730662	R21 - Bear Creek - EDMUD - Detailed Stdy	(5,571.03)			(5,571.03)
9730664	WDT-CA-17-0101 SB43 Devils Den-Fst Trk	2,507.47			2,507.47
9730665	WDT-CA-17-0102 SB43 Gates-ISP	(1,840.39)			(1,840.39)
9730740	CA Department of Corrections #387295/Det	(5,975.70)	364.65		(5,611.05)
9730743	WDT CA-17-0100 SB43 Derrick/ISP	1,832.09			1,832.09
9730760	R21 EBMUD Enos (387729) RESBCT/Detailed	(53,809.59)			(53,809.59)
9730784	WDT SEPV American Canyon/FT	206.98			206.98
9730800	R21 - Bangor Solar - 1402-RD - Det Stdy	(9,489.50)			(9,489.50)
9730820	WDT-CA-17-0090 SB43 Dulgarian/FT	233.16			233.16
9730861	R21 - City Count of SF (Enos 390303)/Det	(6,049.23)			(6,049.23)
9730862	1529-RD City of Paso Robles/Detailed	(6,671.60)			(6,671.60)
9730880	WDT - DRES Quarry 2.3/FT	158.68			158.68
9730940	R21-Calcom Solar-Western Sky Dairy-DS	(849.72)			(849.72)
9730963	WDT - FT - ZGlobal - Eagle 2 Solar	1,552.47			1,552.47
9730964	WDT - FT - Morris 385 LLC - Morris 385	2,677.21			2,677.21
9730966	WDT - FT - El Pomar Parners - El Pomar	830.99			830.99
9731060	R21 - DS - Chowchilla Dairy Power	(10,000.00)			(10,000.00)
9731061	WDT-FT-ET Solar - Midway Towers Comm Sol	1,705.42			1,705.42
9731062	WDT-FT-ET Solar - East Bay Community Sol	2,258.98	90.04		2,349.02
9731182	R21 - Musco Olive Biom Gen - Fac Study	(4,728.92)			(4,728.92)
9731205	WDT - SR - El Pomar Partners - El Pomar	(211.09)			(211.09)
9731208	WDT-SR-ForeFront Power-Dulgarian	(250.27)			(250.27)
9731210	WDT - FT - Solar Electric SEPV Cuyama 2	310.23			310.23
9731211	WDT - SR - Green Light - Eagle 2 Solar	245.43			245.43
9731280	R21-DS-BNB Renewable-Campbell Soup Supp	5,330.78			5,330.78
9731281	R21-DS-Renewable Solar-Danell Brothers	(6,682.46)		6,682.46	
9731287	R21-DIS-Forefront-CDCR-1569-RD	(3,175.94)	3,433.73		257.79
9731300	WDT-SR-Forefront Power-Mouren Farming	558.21			558.21
9731320	WDT - FT - EPRI - SVUSD Bus Barn Storage	4,326.33			4,326.33
9731340	R21 - DIS - West Biofuels - SunWest Bio	(1,918.39)	1,230.41		(687.98)
9731341	R21 - DIS - Syn Tech - Lisa Boone Harris	(4,975.64)			(4,975.64)
9731360	WDT-SIS-Solar Electric-SEPV Cuyama 2	(3,553.60)			(3,553.60)
9731380	R21-DIS-E&J Gallo Winery-Asti Pond Solar	(6,812.45)			(6,812.45)
9731381	R21-DIS-SunPower-EBMUD RESBCT	(41,035.60)			(41,035.60)
9731383	R21-DIS-Maas Energy-Lakeshore Dairy Dig	(7,293.27)			(7,293.27)
9731482	WDT - SIS - Rival Power Peterson Road 2	(5,842.52)			(5,842.52)
9731484	R21 - DIS - JKB Energy-Trinitas Fund II	(2,070.03)			(2,070.03)

9731503	R21-DIS-Concentric-South County Packing	1,099.38			1,099.38
9731504	R21-DIS-ARC Alternatives-City of Lincoln	(9,033.21)			(9,033.21)
9731507	WDT-FT-REP Energy-DRES Quarry 2.4	(68.71)			(68.71)
9731510	WDT-FT-Renewable Prop-Palm Drive Solar C	1,762.55			1,762.55
9731511	WDT-SR-ET Capital-Midway Towers Comm	(2,500.00)			(2,500.00)
9731517	WDT-SR-ET Capital, Inc. East Bay Com Sol	(2,500.00)			(2,500.00)
9731519	WDT-ISP-Calbio Energy-Bar20 Dairy Biogas	2,627.57			2,627.57
9731620	WDT-ISP-Calbio Energy-MaddoxDairyBiogas	(4,297.94)			(4,297.94)
9731621	WDT-ISP-Calbio Energy-Double Diamond	(8,413.78)			(8,413.78)
9731624	R21-DIS--SunPower-West Valley Mission Co	(6,590.77)	1,406.17		(5,184.60)
9731640	WDT-SIS-Green Light Energy-Eagle 2 Solar	(3,766.91)			(3,766.91)
9731680	WDT-FT - DG California Solar-Lodi Solar	113.51			113.51
9731682	R21-DIS-DG Calif Solar, DPIF CA 6 Fresno	(4,131.89)			(4,131.89)
9731702	WDT-ISP-Forefront Power-Nachtigall	(7,771.27)			(7,771.27)
9731720	R21-DIS-ARC Alternatives-County of Kern	(9,149.26)	1,676.47		(7,472.79)
9731722	WDT-SR-Sonoma School-SVUSD Bus Barn Stor	(1,050.99)			(1,050.99)
9731723	WDT-Wireless Sur-Cenergy-NLH1 Solar-0102	189.84			189.84
9731724	WDT-ISP-Forefront Power-Broadman	(5,952.33)			(5,952.33)
9731740	R21-DIS-Forefront-CA Dept of Corr 23100	(2,006.80)	123.37		(1,883.43)
9731741	R21-DIS-Forefront-CA Dept of Corr 23104	(55,184.95)	167.11		(55,017.84)
9731742	R21-DIS-Forefront-CA Dept of Corr 23102	(53,665.57)			(53,665.57)
9731840	R21-DIS-Newcomb-City of Fresno(App22373)	(67,879.29)			(67,879.29)
9731841	WDT-EIT-Forefront-1584-WD Mouren Farming	(5,245.99)			(5,245.99)
9731881	R21-DIS-BloomEnergy-KeysightTechnologies	(5,120.10)			(5,120.10)
9731920	WDT-ISP-CEDWhiteRiverSolar2-WhiteRiver2	(5,292.06)			(5,292.06)
9731921	MMA - Collins Pine Repower - ISO 51161	9,732.02	8,352.61		18,084.63
9731960	WDT-SR-RenewProp-1758WD-PalmDriveSolarC	(271.54)			(271.54)
9731981	WDT-FT-Apex Energy/ZGlobal-Jade Solar	(507.83)			(507.83)
9732000	R21-DIS-SiliconVallCleanWater-12kVSwitch	(2,686.04)			(2,686.04)
9732001	WDT-FT-RenewProp-Silveira Ranch Solar C	434.17			434.17
9732002	WDT-FT-RenewProp-Silveira Ranch Solar D	604.34			604.34
9732003	MMA - Thermalito Powerplant - ISO 51162	28,978.38		(28,978.38)	
9732020	WDT-FT-RenewProp-Silveira Ranch Solar A	814.76			814.76
9732021	WDT-FT-RenewProp-Silveira Ranch Solar B	944.67			944.67
9732060	WDT-SR: Forefront Power-Rocha-1783-WD	(731.61)			(731.61)
9732080	WDT-ISP-YubaCityCogen-WaltonEnergyReliCe	(98,785.26)		98,785.26	
9732100	WDT-ISP: PG&E CoyoteValleyEnergyStorage	14,854.92			14,854.92
9732121	R21-DIS-Forefront- UCSantaCruz App 23113	(6,907.64)	175.77		(6,731.87)
9732122	WDT-FT: Forefront Power - Kern Sunset	(753.85)			(753.85)
9732123	WDT-FT: Forefront Power - Highway 43	1,189.96			1,189.96
9732124	WDT-FT: Forefront Power - Beard	(879.22)			(879.22)
9732180	WDT-FCDS: Yuba City Cogen-Walton Energy	(27,134.72)	1,444.27	25,690.45	
9732181	R21-DIS: South Corner Dairy - Q1611-RD	(6,696.17)		6,696.17	
9732182	WDT-SR: DG Cali Solar - Lodi Solar	(1,497.51)			(1,497.51)
9732262	WDT-ISP: ETCap-EastBayCommSolar1624-WD	(2,048.78)			(2,048.78)
9732263	R21-DIS:CupertinoElec-WonderfulOrch33018	(5,360.47)	168.44		(5,192.03)
9732302	R21-DIS: EnableEnergy-SpecialtyGran34412	(8,197.02)	168.42		(8,028.60)
9732303	WDT-FT: Zero Energy - Fallon Two Rock Rd	1,540.90			1,540.90
9732304	WDT-ISP: Ormat Nevada-Pease Reliability	(9,035.49)			(9,035.49)
9732305	WDT-FCDS: Ormat Nevada-Pease Reliability	(44,392.84)	759.44		(43,633.40)
9732380	R21-DIS: EnableEnergy-SpecialtyGran34465	(2,308.55)	191.29		(2,117.26)
9732388	WDT-SR: Silveira Ranch Solar A	(326.20)			(326.20)
9732389	WDT-SR: Silveira Ranch Solar B	(2,457.64)			(2,457.64)
9732390	WDT-SR: Silveira Ranch Solar C	(2,457.64)			(2,457.64)

9732391	WDT-SR: Silveira Ranch Solar D	(2,457.64)			(2,457.64)
9732400	WDT-SR: Apex Energy - Jade Solar 1865-WD	893.36			893.36
9732460	WDT-ISP: Solvida - PutahCreekSolarFarmN	(10,000.00)			(10,000.00)
9732461	WDT-FCDS: Solvida - PutahCreekSolarFarmN	1,466.11	4,404.79		5,870.90
9732462	WDT-FT: BeckwourthGrid-BeckwourthGrid 1	(319.33)			(319.33)
9732464	R21-DS: Daisy Renew - EarlJohn App 37593	460.15	461.86		922.01
9732467	R21-FS: West Biofuels-SunWest Bioenergy	(6,004.27)			(6,004.27)
9732480	WDT-SR: Forefront Power - Kern Sunset	(318.68)	168.44		(150.24)
9732482	WDT-FT: Kent Solar, LLC - KS Energy	(340.89)			(340.89)
9732483	WDT-SR: Forefront Power - Highway 43	(2,064.85)			(2,064.85)
9732484	R21-DS: CalCom Solar-Moonlight App 38001	(5,551.55)			(5,551.55)
9732486	R21-EIT: West Coast Waste-1827-RD Gen 1	(1,244.08)			(1,244.08)
9732487	R21-DS: Shasta College - Q#1753-RD	(10,000.00)	4,134.51		(5,865.49)
9732500	WDT-CS: Calpine - Cygnus Power Bank	(97,771.05)	16,109.93		(81,661.12)
9732501	WDT-FCDS: Calpine - Cygnus Power Bank	(49,798.73)	218.26		(49,580.47)
9732503	WDT-FT: CalCom Solar - Toyon	(460.11)			(460.11)
9732520	R21-DS: NextEra-BigDPacBuildSMF3-Q1791RD	(8,455.18)			(8,455.18)
9732523	WDT-SR: Forefront Power -Beard Q1888-WD	667.41			667.41
9732622	WDT-EIT: FFPCACommSolar Rocha - 1783WD	(4,312.55)			(4,312.55)
9732660	R21-DS: Ecoplexus-CANatGuard-Q1786-RD	(7,541.23)	497.01		(7,044.22)
9732680	R21-DS: Cupertino E-Wonderful Orch 41293	(4,187.32)	341.80		(3,845.52)
9732720	R21-DS: SyntechBioenergy-RiverOakOrchard	(1,213.72)			(1,213.72)
9732721	R21-SR: Charlies Enterprises 1909-RD	(2,500.00)		2,500.00	
9732781	Repower - Kelly Ridge Powerhouse - SFWPA	11,235.19			11,235.19
9732820	WDT-CS: Origis Operating-Vaquero Storage	(108,695.57)	4,626.98		(104,068.59)
9732821	WDT-FCDS: OrigisOperating-VaqueroStorage	(49,919.85)	545.58		(49,374.27)
9732840	WDT-SIS: Forefront Power - Kern Sunset	(4,077.88)			(4,077.88)
9732841	WDT-SIS: Forefront Power,LLC-Highway 43	(6,675.65)			(6,675.65)
9732842	R21-DS: COofCali DArrigo Bros 114202422	(3,795.55)			(3,795.55)
9732843	WDT-FT: SFPUC-Starr King PV Installation	399.71			399.71
9732844	R21-DS: BessieDig-HilltopHolsteins 38098	440.76			440.76
9732845	WDT-SR: Zero Energy Construct-Highway 43	(2,335.71)			(2,335.71)
9732846	WDT-CS: Calpine Corp-Panthera Power Bank	(76,842.06)	14,976.51		(61,865.55)
9732847	WDT-FCDS: CalpineCorp-PantheraPowerBank	(49,959.93)	181.86		(49,778.07)
9732848	WDT-CS: Capine Corp-Riverrun Power Bank	(96,850.37)	14,505.44		(82,344.93)
9732849	WDT-FCDS: CapineCorp-Riverrun Power Bank	(49,959.93)	181.86		(49,778.07)
9732880	R21-DS: ACElectric-RogerVGroningen 45330	(5,683.61)	175.77		(5,507.84)
9732882	WDT-FT: Soltage-Bradley Gillett Solar 1	336.47			336.47
9732883	WDT-FT:Soltage-San Ardo Pine Vly Solar 1	(318.20)			(318.20)
9732900	WDT-SIS: RenewableProp-SilveiraRanchSolA	(273.12)	2,036.77		1,763.65
9732901	WDT-SIS: RenewableProp-SilveiraRanchSolB	(4,075.35)	10,171.52		6,096.17
9732902	WDT-SIS: RenewableProp-SilveiraRanchSolC	(4,655.75)	10,884.46		6,228.71
9732904	R21-DS: PhoenixEner-NapaRecBiomass2MW	(5,942.63)			(5,942.63)
9732905	R21-DS: AmericanCommod-AbelRoadBioenergy	(1,729.38)	2,363.14		633.76
9732907	WDT-FT: Engie-Hayward EBCE Array	5,423.55			5,423.55
9732908	WDT-ISP:Berry Petroleum-Berry NMW Cogens	(53,482.04)	7,281.90		(46,200.14)
9732909	R21-DS: AmericanCommod-Willows Bioenergy	(4,835.90)	703.08		(4,132.82)
9732940	WDT-FAS: Bar20Dairy - Bar20Dairy1754-WD	(15,000.00)			(15,000.00)
9732941	MMA - Q1011 Colinas de Oro - ISO 51541	989.45		(989.45)	
9732960	WDT-SR: PristineSunFund6-RGA2/SH1 Solar	(914.68)			(914.68)
9732961	R21-DS: Sunpower-TheGapInc-App46139NEMMT	(5,218.37)			(5,218.37)
9732962	R21-DS: City of Lincoln (Airport)	(2,162.57)			(2,162.57)
9733060	WDT-EIT/SIS: ForefrontPower-Beard1888-WD	(6,495.75)			(6,495.75)
9733061	WDT-SR: Kent Solar, LLC - KS Energy	(1,425.59)	642.53		(783.06)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/25/2020	2019/Q4

FOOTNOTE DATA

9733081	WDT-SR: SoltageCaDevCo-SanArdoValleySol1	(85.49)			(85.49)
9733082	WDT-SR: Soltage,LLC-BradleyGillettSolar1	448.40	182.33		630.73
9733083	MMA1-NoQ Moss Landing Unit 6-ISO 51164	7,571.01			7,571.01
9733160	WDT-ISP: CalpineCorporation-CalSunSolar	(66,063.64)	715.79		(65,347.85)
9733164	WDT-FT: GoldenStateRenew-GSRETurkIsland	614.22			614.22
9733165	WDT-FT: GoldenStateRenew - GSRE-OSP	(547.36)			(547.36)
9733166	R21-DS:ArcAlternativesElDoradoUHSD1782RD	(9,819.37)	1,881.77		(7,937.60)
9733169	WDT-FAS: GreenLightEnergy-Eagle 2 1620WD	(14,753.10)			(14,753.10)
9733180	MMA - QF FrickSummitRepower - ISO 51135	3,308.79			3,308.79
9733181	R21-DS: Google-MFABayviewFacSolar50088	(8,763.71)	10,323.86		1,560.15
9733183	WDT-ISP: ZGlobal - Jade Solar_July 2018	2,927.54			2,927.54
9733200	R21-DS: PhoenixEnergy-NorthForkComPower	11,341.75	313.02		11,654.77
9733201	R21-DS: PhoenixEnergy-BlueMountainElectr	5,279.91	156.47		5,436.38
9733240	R21-DS: West Biofuels - Hat Creek Bioene	(10,000.00)	12,089.06		2,089.06
9733302	WDT-ISPReStudy: Strauss Wind Energy, LLC	(22,096.33)	2,134.75		(19,961.58)
9733303	EGI: Forbestown PH - SFWPA - Testing	342.45			342.45
9733304	WDT-SIS:Soltage,LLC-BradleyGillettSolar1	(2,233.90)	218.25		(2,015.65)
9733306	R21-DS-BASSLAKEJOINTELESchApp55332RESBCT	(5,338.39)			(5,338.39)
9733320	R21DIS:CityofMaderaRES-BCT (App 54517)	(9,031.77)	4,300.66		(4,731.11)
9733321	WDT-SIS:Soltage,SanArdoPineValleySolar1	(4,463.88)	72.76		(4,391.12)
9733322	Rule21:DS-MMRConsWAWONAFROZENFOODS-50318	(57,639.74)	4,902.92		(52,736.82)
9733323	WDT-FT-SolarElectricSolution-SEPVBarbar3	47.59	36.39		83.98
9733340	R21:DS-EL DORADO IRRIGATION DISTRICT	(7,446.81)	878.83		(6,567.98)
9733341	R21DIS:CA DEPT of CORRECTIONS(App55059)	(56,485.23)	4,360.59		(52,124.64)
9733361	MMA - NoQ# - Patterson Pass - ISO 51137	720.00		(720.00)	
9733380	WDT-FT-WildcatRenewableRPSantaCruzSolar1	576.99	175.77		752.76
9733381	WDT-FT-WildcatRenewableRPSantaCruzSolar2	648.89	175.77		824.66
9733382	Rule21:DS-JKB EnergySierraPacificAP55806	(57,145.76)	5,149.26		(51,996.50)
9733385	WDT-FT-ApexEnergySolutionsGasCoRdSolar1	(654.52)			(654.52)
9733427	MMA #5 - Q1036 Mustang 2 - ISO 51601	3,256.16	894.67	(4,332.12)	(181.29)
9733440	WDT-SR-GoldenStateReneEng-GSRETurkIsland	(2,500.00)			(2,500.00)
9733480	Rule21:DS-DeltaDiabloCo-Digestion1968-RD	(7,098.06)	3,707.60		(3,390.46)
9733540	WDT-FastTrack-Universal Solar-USPPGE9918	(663.58)			(663.58)
9733541	WDT-FastTrack-Universal Solar-USPPGE8918	(663.58)			(663.58)
9733542	WDT-FastTrack-Universal SolarUSPPGE-7918	(800.70)			(800.70)
9733543	WDT-FastTrack-Universal Solar-USPPGE6918	(879.09)			(879.09)
9733545	WDT-FastTrack-Universal Solar-USPPGE4918	(879.09)			(879.09)
9733546	WDT-FastTrack-Universal Solar-USPPGE3918	(515.10)			(515.10)
9733547	WDT-Fas Track-Universal Solar-USPPGE2918	(800.70)			(800.70)
9733548	WDT-Fast Track-UniversalSolar-USPPGE1918	(261.78)			(261.78)
9733549	WDT-FT-NatelEnergyc/oKinetMurphyHydro	(316.50)			(316.50)
9733550	WDT-FT-RENESOLAPOWERHOL-OspreySolar	281.94			281.94
9733552	WDT-PS-UticaWater&Power(UWPA)-AngelPower	(1,639.53)			(1,639.53)
9733553	WDT-FT-ReneSolaPowerHoldingsTaylorSolar	332.74	175.77		508.51
9733561	R21-Detailed Study-STAMOULES PRODUCE	(7,602.78)	703.08		(6,899.70)
9733562	Rule21DSBerryPetroleumCompy-BerryCogen18	538.41			538.41
9733581	WDT#SR-CITYOFHAYWARDHaywardEBCEArray	(2,500.00)			(2,500.00)
9733600	MMA-Q1278-Westwood Energy Ctr-ISO 52013	1,785.60	3,273.23		5,058.83
9733602	WDT:FT - Pine Flat Solar 1 - Apex Energy	(474.67)			(474.67)
9733603	WDT:FT - Merced 3 - Apex Energy	(281.51)			(281.51)
9733620	WDT-FastTrack-Calcom Solar-Sycamore-Napa	3,852.66			3,852.66
9733621	WDT-SIS- Kent Solar-LLC-KS Energy	606.93	3,729.54		4,336.47
9733640	WDT-SR-RenewableRPSantaCruzSolarQ2031WDT	(647.89)	176.01		(471.88)
9733641	WDT-SR-RenewableRPSantaCruzSolar1Q2030WD	(647.89)	176.01		(471.88)

9733642	R21#Detailed Study-Superior Packing Co.	(9,305.60)	1,982.91		(7,322.69)
9733643	R21:DS:NextEraEnerg114971313DGCAWestside	(58,000.00)	3,412.44		(54,587.56)
9733660	WDT-ISP/FCDS-DGCali-YubaCityEnergyStorag	(9,676.05)	1,509.81		(8,166.24)
9733681	WDT:FT - Corda I - Cratus Energy Mgmt	1,076.11			1,076.11
9733682	WDT:FT - Corda II - Cratus Energy Mgmt	1,076.11			1,076.11
9733700	MMA2 - Q1141 Alamo Springs - ISO 51745	530.79		(530.79)	
9733701	MMA2 - Q1157 Alamo Springs 2 - ISO 51708	215.98		(215.98)	
9733702	WDT:FT - Gonzales - FFP CA Com Solar	(454.88)			(454.88)
9733703	WDT:FT - Washoe Ave - FFP CA Com Solar	640.21	2,909.69		3,549.90
9733704	WDT:SR - Osprey Solar - Renesola Power	(2,392.31)			(2,392.31)
9733705	R21-DS: WonderfulPistachios&Almonds66478	(69,000.00)	19,611.27		(49,388.73)
9733720	R21-DS: Wonderful Pistachios & Almonds	(10,000.00)	705.30		(9,294.70)
9733761	MMA2 - Q1106 Fountain Wind - ISO 51770	803.51	218.25	(1,082.18)	(60.42)
9733762	WDT:ISP - Tranquility - FFP CA Com Solar	(6,970.56)			(6,970.56)
9733763	WDT:ISP - Munoz - FFP CA Com Solar	(8,027.41)	3,200.67		(4,826.74)
9733764	R21-DS: WonderfulPistachios&Almonds67792	(8,784.39)	3,947.65		(4,836.74)
9733765	WDT:SR - 2040-WD - Gas Co Road Solar 1	160.75	145.48		306.23
9733767	R21:DS - City of San Jose (App 68019)	(78,000.00)	22,717.35		(55,282.65)
9733780	WDT:ISP - Leo Solar - Apex Energy	(9,787.24)	1,808.59		(7,978.65)
9733840	R21:DS - RWA/UCM Cogen-Merced Co RWM	(10,000.00)			(10,000.00)
9733842	R21-DS: MacphersonOil-RoundMountainSolar	(10,000.00)			(10,000.00)
9733843	WDT-SR: SycamoreGroup-SycamoreNapa2066WD	(2,500.00)	757.73		(1,742.27)
9733862	WDT–FillInStudyReneSolaPowerTaylorSolar	(2,428.23)	218.24		(2,209.99)
9733881	MMA1 - Q1239 Medeiros Solar - ISO 40030	997.51	4,419.19		5,416.70
9733900	WDT-FT-ApexEnergySolutionsPineFlatSolar2	(1,000.00)	175.77		(824.23)
9733901	WDT-FT-ApexEnergSolutionGasCoRoadSolar2	(1,000.00)	443.35		(556.65)
9733920	WDT-SR-SolarElectricSolutionSEPVBarbara3	(2,500.00)	218.31		(2,281.69)
9733921	WDT–SR-Kinet Inc-Murphys Afterbay Hydro	(1,397.33)	5,040.33		3,643.00
9733922	Rule21:DS-GRANITEROCKCOMPANY(App69212)	(10,000.00)	8,244.23		(1,755.77)
9733923	WDT:SR-Manning Avenue-FFP CA Com Solar	(1,705.40)			(1,705.40)
9733924	Rule21-DS-ChicoElectricRoplastApp#4959	(9,924.12)	8,208.41		(1,715.71)
9733925	WDT-FT-Apex Energy Solutions-Lara Solar	(357.16)	72.78		(284.38)
9733926	WDT-FT-Apex Energy Solutions-Leo Solar2	(748.75)			(748.75)
9733929	WDT-FT-FFPCACommunitySolarBroadman2	(1,000.00)	218.25		(781.75)
9733930	WDT-SR-ApexEnergySolutionsPineFlatSolar1	(1,669.53)			(1,669.53)
9733931	Rule21DS-GOLDENSTATEFC-App71807	(10,000.00)	9,233.02		(766.98)
9733941	WDT-FT-ApexEnergySolutionsPineFlatSolar3	(696.52)			(696.52)
9733960	WDT-FT-UniversalSlAircoupeSolar3((30N27)		36.39		36.39
9734001	WDT:SR - 2083-WD-Corda 1 - Cratus Energy	(2,500.00)	1,921.55		(578.45)
9734002	WDT:SR - 2084-WD-Corda II-Cratus Energy	(2,500.00)	1,921.55		(578.45)
9734003	WDT-FT-ApexEnergySolutionsLLCLeoSolar3	(1,000.00)	363.74		(636.26)
9734045	WDT:FT - WHI Solano R&D - Wind Harvest	(1,000.00)			(1,000.00)
9734101	R21:DS - Fowler Packing Co - App 76191	(10,000.00)	2,322.30		(7,677.70)
9734102	R21:DS - Fowler Packing Co - App 76185	(10,000.00)	4,592.09		(5,407.91)
9734140	WDT:SIS - Osprey Solar - Renesola Power		8,872.73	(10,000.00)	(1,127.27)
9734142	MMA1 - Q1010-Dyer - ISO 51539	152.83	4,341.53	(4,886.54)	(392.18)
9734160	WDT-FillInStudyApexEnergySolutiJadeSolar		5,762.67	(15,000.00)	(9,237.33)
9734220	WDT-SR-FFPCACommunitySolar-WashoeAvenue		1,581.92	(2,500.00)	(918.08)
9734241	WDT-SR-ApexEnergySolutionsGasCoRdSolar2		388.04	(2,500.00)	(2,111.96)
9734242	WDT–SIS-ApexEnergySolutioGasCoRoadSolar1		5,016.37	(10,000.00)	(4,983.63)
9734306	WDT-ISP-CES Electron Farm One,LLC		43.65		43.65
9734307	WDT–SIS-ReneSolaPowerHoldingLLCBroadman2		4,815.52	(10,000.00)	(5,184.48)
9734308	WDT-Fast Track-Division Solar-Lake Solar		445.76	(1,000.00)	(554.24)
9734340	WDT-IS-RenewablPropertiesLakeHermanSolar		7,712.07	(10,000.00)	(2,287.93)

9734343	Rule21DS-ATS-KaiserDublinHUBCancerCenter		4,626.20	(8,000.00)	(3,373.80)
9734381	WDT-SR-ApexEnergySolutionsLeoSolar3			(2,500.00)	(2,500.00)
9734400	WDT:FT - Corda III - Cratus Energy Mgmt		1,348.12	(1,000.00)	348.12
9734401	WDT:FT - Lara Solar - Apex Energy Solar		947.31	(1,000.00)	(52.69)
9734425	WDT-FT-EDFRenewablesEDF-DSSeaBreezeSolar		7,058.84	(1,000.00)	6,058.84
9734440	WDT-FT-Elie MehrdadTrustsolaparkphaseA		1,044.29	(1,000.00)	44.29
9734512	MMA - Q1363-Sandhill C - ISO 53028		4,651.99	(4,933.36)	(281.37)
9734527	WDT-SIS-CratusEnergyManagementCorda1		13,566.63	(10,000.00)	3,566.63
9734528	WDT-SIS-CratusEnergyManagementCorda2		2,933.22	(10,000.00)	(7,066.78)
9734540	Rule21:DS-SUNNYGEMLLC(App 84294)NEMExP		1,976.00	(10,000.00)	(8,024.00)
9734580	WDT-SIS-FFPCACommunitySolarWashoe Avenue		2,327.73		2,327.73
9734584	WDT-IS-Cratus Energy MGMT-Corda IV		6,539.32	(10,000.00)	(3,460.68)
9734600	WDT-IndepFullCapacity-VESI10-ErisStorage		9,445.76	(60,000.00)	(50,554.24)
9734607	WDT–IS-esvolta-lp-TierraRobleEnerStorage		2,306.77	(56,000.00)	(53,693.23)
9734608	WDT-FT-RenewableProper-SoscolFerrySolarA		1,176.47	(1,000.00)	176.47
9734609	WDT-FT-RenewableProper-SoscolFerrySolarB		1,176.47	(1,000.00)	176.47
9734610	WDT-FT-RenewableProp-ByronHotSpringSolar		1,552.22	(1,000.00)	552.22
9734620	Rule21:DS-UNIVERSITYOFTHEPACIFICApp83342		7,989.10	(10,000.00)	(2,010.90)
9734640	WDT-IS-JATONLLC-KecksRoadSolarFacility		2,149.32	(10,000.00)	(7,850.68)
9734641	WDT-FT-RenewableProperti-WilsonHillSolar		2,042.71	(1,000.00)	1,042.71
9734642	Rule21-DetailedStud-SpecialtyGranulesINC		1,367.13	(15,000.00)	(13,632.87)
9734701	R21:DS - SunWest Bioenergy - 2076-RD		370.76	(10,000.00)	(9,629.24)
9734702	WDT:FT-Gas Co Road Solar 3-Apex Energy			(1,000.00)	(1,000.00)
9734703	WDT:FT-Gas Co Road Solar 4-Apex Energy			(1,000.00)	(1,000.00)
9734704	WDT:SIS-Gas Co Road Solar 2-Apex Energy		1,250.90	(10,000.00)	(8,749.10)
9734705	MMA - Q1143-Alpaugh Storage - ISO 51720		895.86	(956.28)	(60.42)
9734706	R21:DS - Specialty Granules - 1912-RD		1,307.24	(15,000.00)	(13,692.76)
9734740	WDT-FTCratusEnergyManagement-Mendoza		734.73	(466.21)	268.52
9734741	WDT-Cluster12-CalPine-CalSunSolar2004-WD		176.29	(50,000.00)	(49,823.71)
9734761	WDT–FullCapacity-VESI11LLC-Eris Storage		217.13	(50,000.00)	(49,782.87)
9734762	WDT:ISP-Redwood Coast Airport Microgrid		8,334.61	(10,000.00)	(1,665.39)
9734860	WDT-FT-GoldenStateRenewable-HuronStorage		813.78	(813.78)	
9734862	WDT-IS-esvolta-lpTierraRobleIIEngStorage		5,479.09	(61,000.00)	(55,520.91)
9734863	Rule21:DGS-CorcoraIrrigationDistrict-5MW		3,318.46	(10,000.00)	(6,681.54)
9734864	WDT–SR-ZGlobal-Lara Solar 2 (2142-WD)		3,474.73	(2,500.00)	974.73
9734880	Rule21:Detailed Study-City of Manteca		7,258.60	(10,000.00)	(2,741.40)
9734904	WDT-SR-RenewableProperti-WilsonHillSolar		3,683.79	(2,500.00)	1,183.79
9734913	WDT–IS-SunPower-UCSFDentalClinics/Cogen		6,025.79	(64,000.00)	(57,974.21)
9734914	Rule21-DS-GRIMMWAYENTERPRI-11412MALAGARD		5,226.08	(10,000.00)	(4,773.92)
9734920	WDT-FTBloomENGPosoCreekFamilyDairyBiogas		247.28	(1,000.00)	(752.72)
9734921	WDT-ISBloomENGSouthpointRanchDairyBiogas		4,887.68	(10,000.00)	(5,112.32)
9734923	WDT–SR-RenewableProper-SoscolFerrySolarB		686.07	(2,500.00)	(1,813.93)
9734924	WDT–SR-RenewableProper-SoscolFerrySolarA		686.07	(2,500.00)	(1,813.93)
9734925	WDT-SR-RenewablePro-ByronHotSpringsSolar		686.07	(2,500.00)	(1,813.93)
9734940	MMA-Q1269 Capetown Wind (BESS)-ISO 51972		1,230.48		1,230.48
9734941	EGI:Facilities Study - Santa Clara Wind		5,712.80	(10,000.00)	(4,287.20)
9734942	EGI:Facilities Study - Forebay Wind		6,536.93	(10,000.00)	(3,463.07)
9734962	Rule21-DS-Windpower-Dole5.6MWWindTurbine		3,412.25	(56,000.00)	(52,587.75)
9734963	WDT-FT-SunwalkerEnergy-ByronSolarFarmLLC		4,107.94	(1,000.00)	3,107.94
9735001	Rule21:DS:MESAWater-BerrendaMWD-StationA		2,576.87	(57,000.00)	(54,423.13)
9735007	EGI:Facilities Study - Collins Pine Co.		15,835.21	(10,000.00)	5,835.21
9735008	MMA - Q1127 Little Bear 3 - ISO 51824		2,914.04	(2,914.04)	
9735009	MMA - Q1128 Little Bear 4 - ISO 51825		3,290.64	(3,290.64)	
9735040	Rule21:DS-CALIFORNIARESOURCESCORPORATION		675.04	(10,000.00)	(9,324.96)

9735041	Rule21-DS-TIMIRAN INC-Huller Add-On		5,431.38	(10,000.00)	(4,568.62)
9735042	WDT-Clu12FCDS-Solvida-PutahCreekFarNorth		70.51	(50,000.00)	(49,929.49)
9735061	WDT-IS-ConflittiEnergy-CESElectroFarmOne		832.77	(10,000.00)	(9,167.23)
9735080	MMA - Q723 Lotus Solar Farm - ISO 50887		1,875.70	(1,875.70)	
9735120	MMA - Q1235 Hudson Solar 1 - ISO 51904		3,725.95	(3,918.05)	(192.10)
9735174	Rule21:DetailedStudy-WAL-MART STORES INC		1,475.37	(10,000.00)	(8,524.63)
9735280	WDT–SR-ApexEnergySolutionGasCoRoadSolar3		5,009.61	(2,500.00)	2,509.61
9735281	WDT–SR-ApexEnergySolutionGasCoRoadSolar4		1,689.47	(2,500.00)	(810.53)
9735301	CCSF Warnerville Sub Rehab		14,956.68	(50,000.00)	(35,043.32)
9735303	WDT-SR-EDFRenewables-EDFDSSeaBreezeSolar		4,784.05	(2,500.00)	2,284.05
9735341	Rule21:DS-FallRiverRCD-McArthurBioenergy		14,702.20	(10,000.00)	4,702.20
9735342	WDT-IS-Dimension CA 1 LLC-G3FarmingTrust		9,859.81	(57,000.00)	(47,140.19)
9735360	NextEra Honey Lake Solar DTT		1,155.20		1,155.20
9735380	Rule21:DS-OLAM WEST COAST-Olam-Firebaugh		7,745.58	(10,000.00)	(2,254.42)
9735381	WDT-IS-SonomaValleySVUSDBusBarnCAISO		948.43	(10,000.00)	(9,051.57)
9735401	WDT-FT-RenewableProper-SoscolFerrySolarC		589.46	(1,000.00)	(410.54)
9735402	WDT-FT-RenewableProper-SoscolFerrySolarD		1,496.42	(1,000.00)	496.42
9735420	WDT–SIS-RenewablePr-ByronHotSpringsSolar		3,293.78	(10,000.00)	(6,706.22)
9735445	Rule21:DS-RWA/UCMCOGENERATION(App104269)		2,382.25	(10,000.00)	(7,617.75)
9735446	Rule21:DS-RWA/UCMCOGENERATION(App104272)			(10,000.00)	(10,000.00)
9735447	Rule21:DS-CityofMaderaWWTP-RES-App103889		9,361.69	(10,000.00)	(638.31)
9735460	WDT-EIT-Byron Solar Farm LLC 2		15,192.15	(10,000.00)	5,192.15
9735461	WDT-SR-Bloom-PasoCreekFamilyDairyBiogas		685.49	(2,500.00)	(1,814.51)
9735500	MMA-Q557-CED White River West2-ISO 50555		517.87	(518.37)	(0.50)
9735560	Rule21:DS-LionBrotherNewstone(App106347)		6,046.01	(10,000.00)	(3,953.99)
9735580	WDT-EIT/SIS-ApexEnerg-LaraSolar2-2142-WD		4,829.07	(10,000.00)	(5,170.93)
9735600	WDT-IS-EC&R SolarDevelopment LLC-Lipizan		4,422.43	(62,000.00)	(57,577.57)
9735642	WDT-FT-Renewable-HatcheryRoadSolarB		1,489.19	(1,000.00)	489.19
9735643	WDT-FT-Renewable-HatcheryRoadSolarA		1,489.19	(1,000.00)	489.19
9735644	WDT-SR-Renewable-Soscol Ferry Solar D		637.67	(2,500.00)	(1,862.33)
9735645	WDT-SR-Renewable-Soscol Ferry Solar C		1,080.65	(2,500.00)	(1,419.35)
9735660	WDT-SR-DivisionSolar-Lake Solar(2137-WD)		478.98	(2,500.00)	(2,021.02)
9735661	MMA-Q1349-Aramis Power Plant-ISO 53024		346.68	(346.68)	
9735680	WDT-FT-NapaJamiesoCanyon-NapaSelfStorage		4,587.36	(1,000.00)	3,587.36
9735707	WDT-FT-GCLNewEnergyHartleySubstation		1,227.63	(1,000.00)	227.63
9735708	WDT-FT-GCLNewEnergyPlumasSubstation		1,163.49	(1,000.00)	163.49
9735709	WDT-FT-Dimension CA1-CA-19-0024-Jorge		901.04	(1,000.00)	(98.96)
9735721	WDT–ISP-ApexEnergySoluti-GasCoRoadSolar3		1,674.63	(10,000.00)	(8,325.37)
9735722	WDT-ISP-ApexEnergySolutio-GasCoRoadSola4		2,323.32	(10,000.00)	(7,676.68)
9735723	Rule21:DS-Main Campus Solar (App 111253)		2,620.85	(10,000.00)	(7,379.15)
9735760	Rule21:DS-DREYERSNestleBakersfiApp111016			(10,000.00)	(10,000.00)
9735762	R21-DS-J R SIMPLOT COMPANY INC		537.01	(10,000.00)	(9,462.99)
9735763	MMA -Q1135-RE ScarletLLC-Scarlet-51732		573.02	(573.02)	
9735780	WDT-FT-SaltbrushPlainsLLC-SaltbrushPlain		1,373.54	(1,000.00)	373.54
9735801	Rule21-DS-GCLNew-2199-RDBESSGonzaleBank3		2,167.52	(10,000.00)	(7,832.48)
9735802	Rule21-DS-GCLNew-2200-RDBESSGonzaleBank4		2,536.04	(10,000.00)	(7,463.96)
9735803	Rule21-DS-CARESOURCESPRODUCTI-CRC-MtPoso		1,811.84	(61,000.00)	(59,188.16)
9735840	Rule21-DS-PlanetaryVentureMFABayviewFac		543.54	(10,000.00)	(9,456.46)
9735880	WD-FT-SonomaUniScho-SVUSD-BusBarnCAISOII		4,558.15	(1,000.00)	3,558.15
9735900	Rule21-DS-FostPoulFmsFosterTravelFeedMil		170.31	(10,000.00)	(9,829.69)
9735901	Rule21-DS-FresnoFarming-FosterBelgravia		170.31	(10,000.00)	(9,829.69)
9735902	WDT-SR-RenewableProp-HatcheryRdSolarA		4,335.78	(2,500.00)	1,835.78
9735903	WDT-SR-RenewableProp-HatcheryRdSolarB		4,695.78	(2,500.00)	2,195.78
9735904	Rule21-DS-SFSpiceCo-BrightPeopleFoods		5,657.93	(10,000.00)	(4,342.07)

9735905	Rule21-DS-TracyDesalinationProj116685552		718.21	(10,000.00)	(9,281.79)
9735906	WDT-FT-RenewablePropByronHighwaySolar		4,740.49	(10,000.00)	(5,259.51)
9735940	WDT-FAS-RedwoodCoastAirportMicrogrid		1,010.59	(15,000.00)	(13,989.41)
9735960	MMA-Q779-WRIGHT SOLAR-ISO 50712		33,441.55		33,441.55
9735961	Rule21-DS-Toma Tek Inc		899.39	(10,000.00)	(9,100.61)
9736000	Rule21-DS-Amazon.com-Amazon BFL1		2,796.86	(10,000.00)	(7,203.14)
9736001	Rule21-DS-AriesLostHillsBioenergy			(10,000.00)	(10,000.00)
9736040	WDT-FT-GoldenStateRenewEnergy-ColmaSolar		1,327.68	(1,000.00)	327.68
9736041	WDT-FT-Vesi14LLC-CeresEnergyStorage		1,407.50	(60,000.00)	(58,592.50)
9736042	WDT-FT-ColdwellSolar1,LLC,RobinsonSolar		5,136.14	(1,000.00)	4,136.14
9736083	WDT-FT-Dimension CA 1 LLC-Jacobs 1		3,186.24	(1,000.00)	2,186.24
9736085	WDT-FT-Dimension CA 1 LLC-Jacobs 2		2,479.88	(1,000.00)	1,479.88
9736100	WDT-FT-ApexEnergySolutionsLLC-JadeSolar3		4,511.68	(1,000.00)	3,511.68
9736180	MMA-Q1441-Kernridge Expansion-ISO 43007		4,458.13		4,458.13
9736181	WDT-SR-SonomaUniSch-SVUSD BusBarnCAISO		1,927.52	(2,500.00)	(572.48)
9736220	MMA-Q1272-Cascade Energy Storage-ISO 519		322.94		322.94
9736221	WDT-SR-NapaJamiesonCnynNapaSelfStorage2		1,828.83	(2,500.00)	(671.17)
9736240	WDT-FT-Hayworth/Fabian LLC-Oakley 3		673.74	(1,000.00)	(326.26)
9736241	WDT-FT-Dimension CA 1 LLC-Henrietta		2,918.22	(1,000.00)	1,918.22
9736261	WDT-FT-Dimension CA 1 LLC-Wellfield		1,778.61	(1,000.00)	778.61
9736262	WDT-FT-Dimension CA 1 LLC-EMH		220.05	(60,000.00)	(59,779.95)
9736263	WDT-FT-GclSysIntegrn-BessUpperLake		2,046.01	(1,000.00)	1,046.01
9736264	WDT-FT-GclSysIntegrn-BessWillits		1,540.75	(1,000.00)	540.75
9736265	WDT-FT-GclSysIntegrn-BessMolino		2,046.01	(1,000.00)	1,046.01
9736266	WDT-FT-GclSysIntegrn-BessHopland		2,046.01	(1,000.00)	1,046.01
9736267	WDT-ISP-Dimension CA 1 LLC-Jorge		673.74	(10,000.00)	(9,326.26)
9736268	WDT-FT-Dimension CA 1 LLC-Mendoza		1,934.57	(1,000.00)	934.57
9736269	EGI:FacilitiesStudy-sPowerAltamontMidway		1,430.06	(10,000.00)	(8,569.94)
9736270	WDT-SR-ColdwellSolar1,LLC-Robinson Solar			(2,500.00)	(2,500.00)
9736271	MMA-Q1028 & Q1029-Little Bear1-ISO 51587		720.00		720.00
9736281	MMA-Q1235-Hudson Solar 1-ISO 51904		772.99		772.99
9736282	WDT-FT-ApexEnergySolutions-NicoleSolar1		2,192.78	(1,000.00)	1,192.78
9736283	WDT-FT-ApexEnergySolutions-NicoleSolar2		1,312.73	(1,000.00)	312.73
9736284	WDT-FT-ApexEnergySolutions-PineFlat1		1,580.56	(1,000.00)	580.56
9736285	WDT-FT-ApexEnergySolutions-PineFlat2		2,020.56	(1,000.00)	1,020.56
9736362	Rule21-DS-GILLIG LLC-GILLIG LLC			(10,000.00)	(10,000.00)
9736363	WDT-SR-GclSysIntegTechnology-BessPlumas			(2,500.00)	(2,500.00)
9736364	WDT-FT-GclSysIntegTechgy-MarysvilleBESS			(1,000.00)	(1,000.00)
9736365	WDT-FT-GclSysIntegTechgy-Cotati BESS		166.57	(1,000.00)	(833.43)
9736400	WDT-FT-ZeroEngyCnstFallonTwoRockRdSolar		166.57	(1,000.00)	(833.43)
9736401	WDT-FT-DimensionCA1AlpaughDacSolar1103		1,144.08	(1,000.00)	144.08
9736402	WDT-FT-GldnStatRnwEngyGsreColmaStorage		2,296.16	(1,000.00)	1,296.16
9736404	Rule21-GoldenStateFcLlc-SCK1 Amazon		666.16	(10,000.00)	(9,333.84)
9736421	WDT-FT-GldnStatRnwEngy-ColmaLithiumIon		1,917.19	(1,000.00)	917.19
9736440	Rule21:DS:SENTINELPEAKRESCA-HopkinsSolar			(10,000.00)	(10,000.00)
9736480	WDT-FT-Borrego-EarthquakeProtnSystems			(10,000.00)	(10,000.00)
9736481	MMA-Q1036-RE Mustang 2-ISO 51601		480.00		480.00
9736520	WDT-SR-GsrEnergy-GsreColmaSolar2317-WD		1,452.66	(2,500.00)	(1,047.34)
9736542	MMA-Q877-CA Flats-ISO 51211		533.07		533.07
9736562	WDT-FT-FresnoDisadvantagedCommunitySolar			(70,000.00)	(70,000.00)
9736563	WDT-SR-ApexEnergySolutions-JadeSolar3			(2,500.00)	(2,500.00)
9736564	WDT-EIT--RenewableProp-HatcheryRdSolarB		1,291.54	(10,000.00)	(8,708.46)
9736565	WDT-EIT--RenewableProp-2296WDByronHwy		1,190.10		1,190.10
9736566	WDT-EIT--RenewableProp-HatcheryRdSolarA		1,291.54	(10,000.00)	(8,708.46)

9736567	Rule21-DS-Chevron-LostHills_Storage			(84,000.00)	(84,000.00)
9736600	WDT-SR-Hayworth/Fabian-Oakley3#2333-WD			(2,500.00)	(2,500.00)
9736676	WDT-ISP-Dimension CA 1 LLC-Mendoza			(10,000.00)	(10,000.00)
9736677	WDT-ISP-Dimension CA 1 LLC-Henrietta			(10,000.00)	(10,000.00)
9736681	MMA-Q1103-Central 40-ISO51821		260.75		260.75
9736682	MMA-Q1117-Aquamarine Westside-ISO51817		260.75		260.75
9736683	MMA-Q1141-Alamo Springs 1-ISO51745		354.55		354.55
9736684	MMA-Q1157-Alamo Springs 2-ISO51708		354.55		354.55
9736685	MMA-Q1242-Pluot-ISO52008		260.75		260.75
9736686	MMA-Q1391-Sonrisa-ISO53017		1,045.60		1,045.60
9736687	MMA-Q272-American Kings Solar-ISO50212-C		433.54		433.54
9736688	MMA-Q779-Wright Solar-ISO50712		439.31		439.31
9736689	MMA-Q946-Northern Orchard Solar-ISO51400		1,821.38		1,821.38
9736690	MMA-Q954-Fifth Standard Solar-ISO51419		1,648.60		1,648.60
9736691	MMA-Q1036-Mustang 2-ISO51601		266.53		266.53
9736692	MMA-Q1223-American kings 9-ISO51935		172.76		172.76
9736693	MMA-Q1259-NorthernOrchardSolar2-ISO51918		172.76		172.76
9736695	MMA-Q1350-Beltran Central Solar-ISO53069		266.53		266.53
9736696	MMA-Q1379-Heartland 1-ISO53048		266.53		266.53
9736697	MMA-Q1380-Hearland 2-ISO53042		957.57		957.57
9736698	MMA-Q1382-Las Camas 1-ISO53030		2,773.15		2,773.15
9736699	MMA-Q1455-Janus-ISO53174		1,130.32		1,130.32
9736700	MMA-Q643W-Re Mustang-ISO50630		266.53		266.53
9736701	MMA-Q643X-Re Tranquility-ISO50647		957.57		957.57
9736702	MMA-Q1120-Chestnut Westsdie-ISO51818		266.53		266.53
9736703	MMA-Q1129-Luna Valley-ISO51746		266.53		266.53
9736704	MMA-Q1139-Westlands Solar Blue-ISO51815		266.53		266.53
9736705	MMA-Q1244-Proxima Solar-ISO51980		266.53		266.53
9736706	MMA-Q1392-Warriors Solar-ISO53025		354.55		354.55
9736707	MMA-Q1394-Driftwood Stella-ISO53051		354.55		354.55
9736708	MMA-Q1397-Sandrini Sol 1-ISO53026		1,045.60		1,045.60
9736709	MMA-Q1443-Angela-ISO53205		266.53		266.53
9736710	MMA-Q1444-Beauchamp Solar-ISO53234		266.53		266.53
9736711	MMA-Q1456-Las Camas 3-ISO53203		1,218.33		1,218.33
9736712	MMA-Q1493-Azalea-ISO53229		266.53		266.53
9736713	MMA-Q1499-Jasmine-ISO53164		266.53		266.53
9736714	WDT-ISP-Dimension CA 1 LLC-Jacobs 1			(10,000.00)	(10,000.00)
9736715	WDT-ISP-Dimension CA 1 LLC-Wellfield			(10,000.00)	(10,000.00)
9736716	WDT-ISP-DimensionCA1-AlpaughDacSolar1003			(10,000.00)	(10,000.00)
9736717	WDT-ISP-Dimension CA 1 LLC-Jacobs2			(10,000.00)	(10,000.00)
9736740	WDT-SR-Q#2352-WD GSRE Colma Storage			(2,500.00)	(2,500.00)
9736741	WDT-SR-Q#2342-WD BESS Upper Lake			(2,500.00)	(2,500.00)
9736742	WDT-SR-Q#2343-WD BESS Hopland			(2,500.00)	(2,500.00)
9736743	WDT-SR-Q#2344-WD BESS Willits			(2,500.00)	(2,500.00)
9736744	WDT-SR-Q#2345-WD BESS Molino			(2,500.00)	(2,500.00)
9736745	WDT-SR-Q#2354-WD BESS Johnson			(2,500.00)	(2,500.00)
9736746	WDT-SR-Q#2356-WD BESS Lafford			(2,500.00)	(2,500.00)
9736750	WDT-SR-Q#2288-WD Saltbrush Plains			(2,500.00)	(2,500.00)
9736754	MMA-Q272-American Kings-ISO50212-C		319.59		319.59
9731721	R21-DIS-Syntech Bioenergy-Carriere Fam F	(4,091.09)			(4,091.09)
9732481	R21-DS: TONY MEIRINHO DAIRY AND SONS	3,623.13			3,623.13
9732760	R21-DS: Marysville Joint Unified School	(8,075.32)	351.53		(7,723.79)
9733120	R21-DS: County of Kern - Industrial	(9,304.60)	383.54		(8,921.06)
9733121	R21-DS: County of Kern - Mt. Vernon	(9,130.59)	2,135.55		(6,995.04)

9733560	Rule21:DSFresnoUnifiedSchoolSunnysideH.S	(9,028.39)	1,976.09		(7,052.30)
9733580	Rule21DS-Re-evaluation-SanJoaquinCounty	(8,449.93)	1,076.82		(7,373.11)
9734141	R21:FS - Abel Road Bioenergy - 1986-RD			(15,000.00)	(15,000.00)
9734383	Rule21-Detailed Study-FIRESTONEWALKERINC		2,456.96	(10,000.00)	(7,543.04)
9734384	Rule21-DS-7THSTANDARDRA-SunPacific-Lerdo		813.55	(10,000.00)	(9,186.45)
9734581	Rule21:DS-CALAMCO		8,773.80	(10,000.00)	(1,226.20)
9735240	Rule21:DS-WAL-MARTSTORES-WAL-MART#1608		706.67	(20,000.00)	(19,293.33)
9735641	R21-FS-TLT Enterprises-HatCreekBioenergy			(15,000.00)	(15,000.00)
9731460	R21-DIS-Golden State FC-Golden State	(1,100.32)	332.24		(768.08)
9731625	R21-DIS-Crimson Resources-Crimson Resour	(2,935.99)			(2,935.99)
9732300	R21-EIT: SynTech-1627-RD Colusa Ind Park	(2,137.54)			(2,137.54)
	Total Generation	(2,535,892.28)	949,439.83	(1,889,806.60)	(3,476,259.05)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	CORE BROKERAGE FEE	1,151,752	6,504,601	400	6,734,374	921,979
2	Amortization : < 12 MONTHS					
3	PURCHASED GAS BALANCING ACCOUNT	10,667,836	1,515,961,917	400	1,508,357,296	18,272,457
4	Amortization : < 12 MONTHS					
5	BCA CHARGE ACCOUNT	946,648	2,270,599	400	5,167,426	-1,950,179
6	Amortization : < 12 MONTHS					
7	CA ALTERNATE RATES FOR ENERGY	42,641,819	534,574,447	400	500,860,731	76,355,535
8	Amortization : < 12 MONTHS					
9	CA ALTERNATE RATES FOR ENERGY PROGRAM-GAS	(24,310,004)	133,560,004	400	130,726,854	-21,476,854
10	Amortization : < 12 MONTHS					
11	ELECTRIC HAZARDOUS SUBSTANCE BALANCING	39,212,198	68,746,929	182.3	78,458,281	29,500,846
12	Amortization : < 12 MONTHS					
13	GAS HAZARDOUS SUBSTANCE BALANCING ACCOUNT	91,495,127	160,409,500	182.3	183,069,321	68,835,306
14	Amortization : < 12 MONTHS					
15	CORE FIXED COST GAS BALANCING ACCOUNT	333,402,345	2,711,910,318	400	2,741,700,584	303,612,079
16	Amortization : < 12 MONTHS					
17	TRANSITION COST - NONCORE BALANCING ACCOUNT	(33,444,673)	185,901,091	400	187,121,657	-34,665,239
18	Amortization : < 12 MONTHS					
19	CORE PIPELINE DEMAND CHARGE ACCOUNT	13,490,911	524,073,000	400	527,592,235	9,971,676
20	Amortization : < 12 MONTHS					
21	CEE INCENTIVE ELECTRIC BALANCING ACCOUNT	(1,257,262)	19,485,310	400	9,455,285	8,772,763
22	Amortization : < 12 MONTHS					
23	CEE INCENTIVE GAS BALANCING ACCOUNT	616,270	5,784,842	400	3,467,692	2,933,420
24	Amortization : < 12 MONTHS					
25	GAS CORE FIRM STORAGE ACCOUNT	4,262,020	84,639,048	400	85,042,056	3,859,012
26	Amortization : < 12 MONTHS					
27	ENERGY RESOURCE RECOVERY ACCOUNT	(53,109,337)	5,172,926,535	400	5,735,828,372	-616,011,174
28	Amortization : < 12 MONTHS					
29	ENERGY RECOVERY BONDS BALANCING ACCOUNT	(46,396,342)	67,645,760	400	17,580,731	3,668,687
30	Amortization : < 12 MONTHS					
31	ELECTRIC PRICE RISK MANAGEMENT - CURRENT	27,367,811	104,676,539	555	108,497,737	23,546,613
32	Amortization : NO STATED					
33	ENVIRONMENTAL COMPLIANCE NON-HSM	39,269,502	4,378,895	228.4	8,689,183	34,959,214
34	Amortization : 32 YEARS					
35	ENVIRONMENTAL COMPLIANCE	223,279,009	47,297,117	182.3	37,109,976	233,466,150
36	Amortization : 32 YEARS					
37	DISTRIBUTION REVENUE ADJUSTMENT MECHANISM	159,677,883	5,151,234,360	400	5,341,691,050	-30,778,807
38	Amortization : < 12 MONTHS					
39	DEFERRED DEBIT - GAS RESERVES (CONTRA BALANCING	(334,368,598)	252,961,206	400	444,994,877	-526,402,269
40	Amortization : < 12 MONTHS					
41	TRANSMISSION REVENUE BALANCING ACCOUNT	(70,745,931)	222,394,301	400	220,492,137	-68,843,767
42	Amortization : < 12 MONTHS					
43	RELIABILITY SERVICES BALANCING ACCOUNT	(55,890,385)	31,085,369	400	24,410,997	-49,216,013
44	TOTAL	5,845,482,579	39,103,572,267		37,921,814,029	7,027,240,817

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)		400		-999,999,999
3	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)		400		-999,999,999
4	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)		400		-999,999,999
5	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)		400		-999,999,999
6	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(384,871,481)	2,089,828,341	400	2,026,684,039	-321,727,179
7	Amortization : < 12 MONTHS					
8	GAS PRICE RISK MANAGEMENT - CURRENT	1,660,566	7,674,322	807	7,737,021	1,597,867
9	Amortization : NO STATED					
10	TRANSMISSION ACCESS CHARGE BALANCING ACCOUNT	127,609,601	349,550,029	400	468,021,748	9,137,882
11	Amortization : < 12 MONTHS					
12	DWR POWER CHARGE COLLECTION BALANCING	(57,216)	3,068,826	400	3,985,664	-974,054
13	Amortization : < 12 MONTHS					
14	PUBLIC PURPOSE PROGRAMS REVENUE ADJUSTMENT	(28,848,079)	250,698,763	400	243,785,405	-21,934,721
15	Amortization : < 12 MONTHS					
16	MODIFIED TRANSITION COST BALANCING ACCOUNT	18,103,438	201,044,137	400	225,736,471	-6,588,896
17	Amortization : < 12 MONTHS					
18	END-USE CUSTOMER REFUND ADJUSTMENT	(7,765,537)	7,213,618	400	210,883	-762,802
19	Amortization : < 12 MONTHS					
20	CATASTROPHIC EVENT MEMORANDUM ACCOUNT	667,879,275	342,681,056	182.3	181,970,716	828,589,615
21	Amortization : < 12 MONTHS					
22	GAS PUBLIC PURPOSE PROGRAM SURCHARGE MEMO	44,470,387	266,451,774	186	267,436,043	43,486,118
23	Amortization : < 12 MONTHS					
24	PROCUREMENT ENERGY EFFICIENCY REV. ADJ.	8,439,402	77,856,809	400	211,106,294	-124,810,083
25	Amortization : < 12 MONTHS					
26	FAMILY ELECTRIC RATE ASSISTANCE BALANCING ACCT	5,340,841	6,968,597	400	5,340,891	6,968,547
27	Amortization : < 12 MONTHS					
28	NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA	999,999,999		182.3		999,999,999
29	NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA	999,999,999		182.3		999,999,999
30	NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA	999,999,999		182.3		999,999,999
31	NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA	199,420,006	120,754,582	182.3	62,209,893	257,964,695
32	Amortization : < 12 MONTHS					
33	LAND CONSERV. PLAN ENV. REMEDIATION MEMO ACCT.	1,400,211	2,112,733	182.3	1,400,211	2,112,733
34	Amortization : < 12 MONTHS					
35	CA SOLAR INITIATIVE THERMAL PROGRAM MEMO	7,998,175	8,012,335	400	7,006,852	9,003,658
36	Amortization : < 12 MONTHS					
37	DIABLO CANYON SEISMIC STUDIES BALANCING ACCT	9,273,395	3,996,327	182.3	4,688,198	8,581,524
38	Amortization : < 12 MONTHS					
39	Wildfire Expense Memorandum Account - Gas		12,070,022	400		12,070,022
40	Amortization : > 12 MONTHS					
41	Wildfire Expense Memorandum Account - Electric		14,575,884	400		14,575,884
42	Amortization : > 12 MONTHS					
43	GAS HAZARDOUS SUBSTANCE REGULATORY ASSET	520,984,354	110,367,229	182.3	86,597,234	544,754,349
44	TOTAL	5,845,482,579	39,103,572,267		37,921,814,029	7,027,240,817

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 : 32 YEARS					
2	GAS NON-HAZARDOUS SUBSTANCE REGULATORY ASSET	133,072,864	3,060,073	228.4	4,029,204	132,103,733
3	Amortization : 32 YEARS					
4	NON CURRENT HSM BA ELEC	28,881,855	69,931,798	182.3	63,694,490	35,119,163
5	Amortization : > 12 MONTHS					
6	NON CURRENT HSM BA GAS	67,390,995	163,174,196	182.3	148,620,478	81,944,713
7	Amortization : > 12 MONTHS					
8	FIRE HAZARD PREVENTION MEMO ACCT	308,776,057	175,116,300	182.3	179,779,198	304,113,159
9	Amortization : < 12 MONTHS					
10	ELECTRIC PRICE RISK MANAGEMENT - NONCURRENT	89,714,060	554,175,612	555	519,849,305	124,040,367
11	Amortization : NO STATED					
12	VEGETATION MANAGEMENT REG. ASSET - CURRENT	22,084,136	373,357,633	400	336,607,537	58,834,232
13	Amortization : < 12 MONTHS					
14	FASB 109 REGULATORY ASSET		629,755,550	282	377,545,108	252,210,442
15	Amortization : 1-45 YEARS					
16	GAS TRANSMISSION AND STORAGE REVENUE SHARING	(7,579,392)	406,135,295	400	443,290,362	-44,734,459
17	Amortization : < 12 MONTHS					
18	NUCLEAR DECOMMISSIONING ADJUSTMENT MECHANISM	(17,452,976)	111,545,820	400	81,346,141	12,746,703
19	Amortization : 2 YEARS					
20	DEPARTMENT OF ENERGY LITIGATION BALANCING	(29,056,854)	29,105,513	182.3	25,402,739	-25,354,080
21	Amortization : > 12 MONTHS					
22	DEMAND RESPONSE EXPENDITURES BALANCING	(7,721,609)	35,205,651	400	38,597,472	-11,113,430
23	Amortization : < 12 MONTHS					
24	AMCDOP-COST ADUST MECHANISM-OTHER	37,961,264	48,843,109	400	147,892,939	-61,088,566
25	Amortization : <12 MONTHS					
26	NEW SYSTEM GENERATION BA	118,944,523	248,777,062	400	181,202,881	186,518,704
27	Amortization : < 12 MONTHS					
28	ELECTRIC PROGRAM INVESTMENT CHARGE	(2,799,937)	93,762,128	400	86,864,786	4,097,405
29	Amortization : < 12 MONTHS					
30	GREENHOUSE GAS EXPENSE MEMO ACCOUNT	(1,019,683)	453,971	400	46,302	-612,014
31	Amortization : NO STATED					
32	GAS PROGRAM BALANCING ACCOUNT	51,892,573	124,916,502	400	173,007,827	3,801,248
33	Amortization : < 12 MONTHS					
34	GREENHOUSE GAS EXPENSE MEMORANDUM ACCOUNT -	850,630	308,848	400	34,775	1,124,703
35	Amortization : < 12 MONTHS					
36	GAS TRANSMISSION & STORAGE MEMO ACCOUNT	112,912,548	86,617,477	400	139,721,269	59,808,756
37	Amortization : < 12 MONTHS					
38	GREEN TARIFF SHARED RENEWABLES MEMORANDUM	5,658,587	2,607,770	400	1,469,848	6,796,509
39	Amortization : < 12 MONTHS					
40	GPBA - GHG OPERATIONAL COSTS SUBACCOUNT	5,934,566	10,663,786	400	28,484,916	-11,886,564
41	Amortization : <12 MONTHS					
42	GREEN TARIFF SHARED RENEWABLES BALANCING	4,498,798	11,301,113	400	15,523,339	276,572
43	Amortization : <12 MONTHS					
44	TOTAL	5,845,482,579	39,103,572,267		37,921,814,029	7,027,240,817

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	03/25/2020	End of 2019/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	DISTRIBUTED RESOURCES PLAN MEMORANDUM ACCT	495,377	2,019,896	400		2,515,273
2	Amortization : > 12 MONTHS					
3	DEMAND RESPONSE EXPENDITURES BA - DRAM	(13,524,761)	9,557,050	400	6,639,269	-10,606,980
4	Amortization : > 12 MONTHS					
5	NONCURR WILDFIRE EXP MEMO ACCT - GAS	103,948,670	92,494,970	182.3	12,999,673	183,443,967
6	Amortization : > 12 MONTHS					
7	NONCURR WILDFIRE EXP MEMO ACCT - ELEC	213,354,963	181,014,419	182.3	44,833,287	349,536,095
8	Amortization : > 12 MONTHS					
9	BA - PORTFOLIO ALLOCATION BAL ACCOUNT		5,879,323,980	400	5,127,312,108	752,011,872
10	Amortization : <12 MONTHS					
11	HLBA - CURRENT		9,632,621	182.3	81,395,825	-71,763,204
12	Amortization : <12 MONTHS					
13	NRCRBA - CURRENT		53,515,912	182.3	42,361,906	11,154,006
14	Amortization : <12 MONTHS					
15	FIRE RISK MITIGATION MEMO ACCT		885,119,160	182.3	777,169,471	107,949,689
16	Amortization : <12 MONTHS					
17	CALI CONSUMER PRIVACY ACT MEMO ACCT-ELEC		6,390,884	182.3		6,390,884
18	Amortization : > 12 MONTHS					
19	CALI CONSUMER PRIVACY ACT MEMO ACCT-GAS		5,228,905	182.3		5,228,905
20	Amortization : > 12 MONTHS					
21	LINE 407 MEMO ACCT NC	3,474,817	3,528,363	182.3		7,003,180
22	Amortization : >12 MONTHS					
23	CRTICAL DOCS PROGRAM MEMO ACCT NC	8,444,395	6,870,673	182.3	3,094,912	12,220,156
24	Amortization : >12 MONTHS					
25	TRANSMISSION INTEGRITY MGMT BAL ACCT		106,743,862	182.3		106,743,862
26	Amortization : >12 MONTHS					
27	HYDRO PIPELINE TESTING MEMO ACCT	90,115,840	2,040,947	182.3		92,156,787
28	Amortization : >12 MONTHS					
29	INTEGRATED DISTRIBUTION ENERGY RESOURCES	223,140	239,516	400		462,656
30	Amortization : > 12 MONTHS					
31	CATASTROPHIC EVENT MEMORANDUM ACCOUNT - GAS		2,002,531	400	101,124	1,901,407
32	Amortization : < 12 MONTHS					
33	MISC ELEC-CURRENT-FERC INTEREST BEARING	57,291,157	6,940,287	400	3,741,219	60,490,225
34	Amortization : <12 MONTHS					
35	TREE MORTAILITY NON-BYPASSABLE CHARGE BAL ACCT		101,321,901	400	38,680,204	62,641,697
36	Amortization : <12 MONTHS					
37	Wildfire Mitigation Plan Memo Acct		891,904,460	182.3	359,708,326	532,196,134
38	Amortization : <12 MONTHS					
39	MISCELLANEOUS GAS REG ASSET - CURRENT	23,940,436	343,964,889	VARIOUS	355,867,567	12,037,758
40	Amortization : < 12 MONTHS					
41	MISCELLANEOUS ELECTRIC REG ASSET - CURRENT	28,922,134	74,546,108	VARIOUS	32,836,149	70,632,093
42	Amortization : < 12 MONTHS					
43	ACCUM AMORT - URG PLANT REG ASSET	3,520,575		405		3,520,575
44	TOTAL	5,845,482,579	39,103,572,267		37,921,814,029	7,027,240,817

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	03/25/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Amortization : < 12 MONTHS					
2	MOBILE HOME PARK BA ELECTRIC NC	24,733,252	13,164,390	597	8,988,655	28,908,987
3	Amortization : > 12 MONTHS					
4	MOBILE HOME PARK BA GAS NC	27,716,508	6,009,525	893	6,056,272	27,669,761
5	Amortization : > 12 MONTHS					
6	MOBILE HOME PARK BA ELECTRIC CURRENT	2,431,506	4,193,884	597	3,286,368	3,339,022
7	Amortization : < 12 MONTHS					
8	MOBILE HOME PARK BA GAS CURRENT	2,731,286	4,452,597	893	3,597,242	3,586,641
9	Amortization : < 12 MONTHS					
10	REG ASSET - MISCELLANEOUS GAS - NON-CURRENT	30,761,653	676,820,569	400	564,883,382	142,698,840
11	Amortization : > 12 MONTHS					
12	MISCELLANEOUS ELECTRIC REG ASSET - NONCURRENT	163,544,647	641,847,752	549	478,695,325	326,697,074
13	Amortization : 25 YEARS					
14	REG ASSET - ABANDONED CAPITAL PROJECTS	25,018,853	13,275,211	400	3,605,302	34,688,762
15	Amortization : < 12 MONTHS					
16	REGULATORY ASSET-CEMA-ELEC-NONCURRENT	992,866,226	586,782,741	588	880,502,773	699,146,194
17	Amortization : > 12 MONTHS					
18	CEMA GAS NONCURRENT	48,718,507	73,203,680	400	76,239,860	45,682,327
19	Amortization : > 12 MONTHS					
20	MOBILE HOME PARK BALANCING ACCOUNT - ELECTRIC	18,561,367	24,641,394	182.3	18,655,930	24,546,831
21	Amortization : <12 MONTHS					
22	MOBILE HOME PARK BALANCING ACCOUNT - GAS	17,625,113	24,953,909	182.3	18,118,247	24,460,775
23	Amortization : <12 MONTHS					
24	WILDFIRES CUSTOMER PROTECTIONS MEMO ACCT - E	2,209,780	2,170,682	400	279,456	4,101,006
25	Amortization : > 12 MONTHS					
26	WILDFIRES CUSTOMER PROTECTIONS MEMO ACCT- G	1,579,497	1,776,013	400	140	3,355,370
27	Amortization : > 12 MONTHS					
28	FINANCING COSTS REGULATORY ASSET	15,656,883	179,827,637	428	29,457,590	166,026,930
29	Amortization : 20 YEARS					
30	URG PLANT REGULATORY ASSET - NONCURRENT	944,805,000		407.4		944,805,000
31	Amortization : 22 YEARS					
32	URG PLANT REGULATORY ASSET - TAX	183,010,953		182.3		183,010,953
33	Amortization : 11 YEARS					
34	ACCUM AMORT - URG PLANT REG ASSET NON CURRENT	(688,732,723)		405	42,243,000	-730,975,723
35	Amortization : 12 YEARS					
36	ACC AMT - PLANT RA TAX	(165,408,053)		405	3,520,572	-168,928,625
37	Amortization : 11 YEARS					
38	UNAMORTIZED FINANCIAL HEDGING COST	11,943,650		428	836,195	11,107,455
39	Amortization : 20 YEARS					
40	PENSION REGULATORY ASSET	999,999,999		926		999,999,999
41	PENSION REGULATORY ASSET	947,103,872	3,488,277	926	127,464,496	823,127,653
42	Amortization : INDEFINITE					
43	URG PLANT REGULATORY ASSET - CURRENT	42,239,000		407.4		42,239,000
44	TOTAL	5,845,482,579	39,103,572,267		37,921,814,029	7,027,240,817

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	MAJOR EMERGENCY BALANCING ACCOUNT	(21,964,713)	250,365,833	182.3	168,141,516	60,259,604
3	Amortization : <12 MONTHS					
4	FIN 47 - REGULATORY ASSET	19,154,481	2,471,526	101	3,656,273	17,969,734
5	Amortization : NO STATED					
6	RESIDENTIAL RATE REFORM MEMORANDUM ACCOUNT	16,636,337	22,794,917	182.3	26,256,993	13,174,261
7	Amortization : <12 MONTHS					
8	REGULATORY ASSET - HYRDO NONCURRENT	10,856,445	202,184	400		11,058,629
9	Amortization : > 12 MONTHS					
10	FINANCING COSTS - CURRENT	1,380,572	18,391,388	428	1,268,112	18,503,848
11	Amortization : < 12 MONTHS					
12	UNAMORTIZED FINANCIAL HEDGING COST CURRENT	836,195		428		836,195
13	Amortization : < 12 MONTHS					
14	NEW ENVIRONMENTAL REGULATIONS BALANCING	10,549,948	25,200,610	400	15,701,473	20,049,085
15	Amortization : > 12 MONTHS					
16	DIABLO CANYON RETIREMENT BAL ACCT (DEPR) - NC	21,992,387	27,032,762	400		49,025,149
17	Amortization : > 12 MONTHS					
18	DCRBA - DCPP EMPLOYEE RETENTION PROGRAM	32,786,330	94,757,195	400	72,777,825	54,765,700
19	Amortization : > 12 MONTHS					
20	San Joaq. Valley Disadv. Comm. Pilot BA		871,800	400	3,844,711	-2,972,911
21	Amortization : < 12 MONTHS					
22	Disadv Comm Single Family Solar Homes Memo Acct		3,890,985	400		3,890,985
23	Amortization : < 12 MONTHS					
24	San Joaq. Valley Disadv. Comm. Data Gath Plan MemoC		424,551	400		424,551
25	Amortization : < 12 MONTHS					
26	AB802MA - E (CURRENT)		1,524,267	182.3		1,524,267
27	Amortization : < 12 MONTHS					
28	AB802MA - G (CURRENT)		1,247,127	182.3		1,247,127
29	Amortization : < 12 MONTHS					
30	Miscellaneous minor items	101,992,135	3,671,225,248	VARIOUS	3,773,017,950	199,433
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	5,845,482,579	39,103,572,267		37,921,814,029	7,027,240,817

Schedule Page: 232.1 Line No.: 2 Column: b

The FERC software will not allow the entire beginning balance of ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT of ($4,384,871,477) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 2: (999,999,999)

Line 3: (999,999,999)

Line 4: (999,999,999)

Line 5: (999,999,999)

Line 6: (384,871,481)

Total (4,384,871,477)

Schedule Page: 232.1 Line No.: 2 Column: f

The FERC software will not allow the entire ending balance of ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT of ($4,321,727,175) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 2: (999,999,999)

Line 3: (999,999,999)

Line 4: (999,999,999)

Line 5: (999,999,999)

Line 6: (321,727,179)

Total (4,321,727,175)

Schedule Page: 232.1 Line No.: 28 Column: b

The FERC software will not allow the entire beginning balance of NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA of $3,199,420,003 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 28: 999,999,999

Line 29: 999,999,999

Line 30: 999,999,999

Line 31: 199,420,006

Total 3,199,420,003

Schedule Page: 232.1 Line No.: 28 Column: f

The FERC software will not allow the entire ending balance of NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA of $3,257,964,692 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 28: 999,999,999

Line 29: 999,999,999

Line 30: 999,999,999

Line 31: 257,964,695

Total 3,257,964,692

Schedule Page: 232.3 Line No.: 39 Column: d

Primarily internal labor expenses. Offset to 182.3 - Other Regulatory Assets and 254 - Other Regulatory Liabilities

Schedule Page: 232.3 Line No.: 41 Column: d

Primarily internal labor expenses. Offset to 182.3 - Other Regulatory Assets, 549 - Misc. Other Power Generation Expenses and 253 - Other Deferred Credits.

Schedule Page: 232.4 Line No.: 40 Column: b

The FERC software will not allow the entire beginning balance of PENSION REGULATORY ASSET of $1,947,103,871 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 40: 999,999,999

Line 41: 947,103,872

Total 1,947,103,871

Schedule Page: 232.4 Line No.: 40 Column: f

The FERC software will not allow the entire ending balance of PENSION REGULATORY ASSET of $1,823,127,652 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 40: 999,999,999

Line 41: 823,127,653

Total 1,823,127,652

Schedule Page: 232.5 Line No.: 30 Column: d

Activity primarily related to BALANCING ACCOUNT - UTILITY GENERATION, GAS PRICE RISK MANAGEMENT - NONCURRENT, TRANSMISSION INTEGRITY MGMT BALACCT-CURR, AB802 MEMO ACCOUNT - GAS, BIORAM

FOOTNOTE DATA

MEMO ACCOUNT,GAS PIPELINE EXPENSE AND CAPITAL BAL ACCT,HYDRO LICENSING BALANCING ACCOUNT with offsets to 182.3, 400, 555 and 807.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	-19,282,202	1,257,685,455	VARIOUS	1,251,765,010	-13,361,757
2	Customer Advance for Constructn	7,655,843	418,115	VARIOUS	598,657	7,475,301
3	Development Costs	45,612,971	40,558,132	131	35,903,672	50,267,431
4	Payments for MLX					
5	and Non-Energy Invoices	1,409,200	845,151,611	VARIOUS	845,293,964	1,266,847
6	Payments for Main Line					
7	Extension	-11,497,007	151,341,029	VARIOUS	142,607,377	-2,763,355
8	Clearing Account for					
9	JP Morgan Chase	1,106,067	20,931,088	VARIOUS	20,889,516	1,147,639
10	Payroll Clearing Account	338,622	13,267,628,120	Various	13,267,079,955	886,787
11	Land Surplus	1,039,263	355,065	930.2		1,394,328
12	Reimb Transm Svc, Gen Intercons	-620,867	4,971,211	VARIOUS	5,493,049	-1,142,705
13	Miscellaneous minor items	311,247	24,899,134	VARIOUS	25,184,412	25,969
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						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	26,073,137				45,196,485

Schedule Page: 233 Line No.: 1 Column: d
Typical Accounts charged: 131, 142

Schedule Page: 233 Line No.: 2 Column: d
Typical Accounts charged: 456, 495

Schedule Page: 233 Line No.: 5 Column: d
Typical Accounts charged: 131, 143

Schedule Page: 233 Line No.: 7 Column: d
Typical Accounts charged: 131, 252

Schedule Page: 233 Line No.: 9 Column: d
Typical Accounts charged: 131, 143, 559

Schedule Page: 233 Line No.: 10 Column: d
Typical Accounts charged: 131

Schedule Page: 233 Line No.: 12 Column: d
Typical Accounts charged: 131, 143

Schedule Page: 233 Line No.: 13 Column: c
Activity primarily reflects undistributed cash receipts.

Schedule Page: 233 Line No.: 13 Column: d
Typical Accounts charged 182.3 and 236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	-42,478,580	-43,418,496
3	Compensation	50,033,114	4,278,296
4	CIAC	-121,829,617	-119,148,840
5	Injuries and Damages	3,478,176,873	6,565,630,896
6	CCFT	145,217,541	91,994,688
7	Other	-437,277,748	946,255,053
8	TOTAL Electric (Enter Total of lines 2 thru 7)	3,071,841,583	7,445,591,597
9	Gas		
10	Environmental	-77,136,703	-115,579,841
11	Compensation	36,918,182	28,120,772
12	CIAC	168,443,372	168,789,262
13	Injuries and Damages	-39,315,702	-41,616,258
14	CCFT	-45,289,022	-24,398,939
15	Other	1,372,702,830	1,251,190,776
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,416,322,957	1,266,505,772
17	Other (Specify)	537,426,086	791,628,533
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	5,025,590,626	9,503,725,902

Notes

Electric Other - Line 7	Balance at Beginning of the year	Balance at end of the year
Vacation Paid		19,679,208
Net Operating Loss	(1,034,516,558)	(498,617,637)
Property Tax	55,829,849	15,958,875
Other	541,408,961	1,409,234,607
Subtotal	(437,277,748)	946,255,053
Gas Other - Line 15		
Vacation Paid		8,123,444
Net Operating Loss	1,099,437,035	862,880,446
Property Tax	21,039,376	7,749,033
Other	252,226,419	372,437,853
Subtotal	1,372,702,830	1,251,190,776
Other - Line 17		
CCFT	(24,571,406)	(33,432,555)
Compensation	2,353,116	2,302,576
Net Operating Loss	619,254,913	887,460,536
Property Tax	(78,808,715)	(78,809,974)
Other	19,198,176	14,107,950
Subtotal	537,426,084	791,628,533

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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 Electric 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		
6				
7	Registered with the American Stock Exchange			
8	Preferred, Cumulative			
9	Redeemable: Without Mandatory Redemption			
10	4.36%	418,291	25.00	25.75
11	4.50%	611,142	25.00	26.00
12	4.80%	793,031	25.00	27.25
13	5.00%	1,778,172	25.00	26.75
14	5.00% - Series A	934,322	25.00	26.75
15	7.04%	3,000,000	25.00	
16	Undesignated in Class	56,180,217		
17				
18	SubTotal Redeemable Without	63,715,175		
19	Mandatory Redemption			
20				
21	Registered with the American Stock Exchange			
22	Non-Redeemable			
23	5.00%	400,000	25.00	
24	5.50%	1,173,163	25.00	
25	6.00%	4,211,662	25.00	
26				
27	SubTotal Non-Redeemable	5,784,825		
28				
29	Redeemable: With Mandatory Redemption			
30	6.30%	2,500,000	25.00	
31	6.57%	3,000,000	25.00	
32	Undesignated in Class	10,000,000	100.00	
33				
34	SubTotal Redeemable With	15,500,000		
35	Mandatory Redemption			
36				
37	TOTAL PREFERRED	85,000,000		
38				
39				
40				
41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

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

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

Redeemed on August 31, 2005.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid in Capital	
2	Equity Infusions from Parent Company	6,729,587,624
3	Excess Tax Benefit on Stock Based Compensation	50,960,304
4		
5		
6		
7		
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	6,780,547,928

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	COMMON	25,143,083
2		
3	PREFERRED, CUMULATIVE:	
4	Redeemable - $25 par value per share:	
5	4.36%	29,509
6	4.50%	387,663
7	4.80%	777,999
8	5.00%	1,758,375
9	5.00% - Series A	158,204
10		
11	Non-Redeemable - $25 par value per share:	
12	5.00%	73,717
13	5.50%	173,730
14	6.00%	449,606
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	28,951,886

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Senior Notes 3.50% due 2020 (A)	550,000,000	4,205,770
2			2,728,000 D
3	Senior Notes 3.50% due 2020	250,000,000	1,897,267
4			6,840,000 D
5	'Senior Notes 4.25% due 2021	300,000,000	2,270,404
6			243,000 D
7	Senior Notes 3.25% due 2021	250,000,000	1,981,515
8			1,312,500 D
9	Senior Notes 2.45% due 2022	400,000,000	3,251,743
10			1,164,000 D
11	Senior Notes 3.25% due 2023	375,000,000	2,924,964
12			1,901,250 D
13	Senior Notes 4.25% due 2023	500,000,000	4,061,237
14			1,175,000 D
15	Senior Notes 3.85% due 2023	300,000,000	2,505,170
16			543,000 D
17	Senior Notes 3.75% due 2024	450,000,000	3,672,801
18			445,500 D
19	Senior Notes 3.40% due 2024	350,000,000	2,788,492
20			262,500 D
21	Senior Notes 3.50% due 2025	400,000,000	3,471,059
22			2,540,000 D
23	Senior Notes 3.50% due 2025	200,000,000	1,709,814
24			-2,716,000 P
25	Senior Notes 2.95% due 2026	600,000,000	5,241,785
26			1,596,000 D
27	Senior Notes 3.30% due 2027	400,000,000	3,306,994
28			1,420,000 D
29	Senior Notes 3.30% due 2027	1,150,000,000	9,322,742
30			3,404,000 D
31	Senior Notes 4.65% due 2028	300,000,000	2,587,342
32			852,000 D
33	TOTAL	19,887,100,000	273,179,138

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Senior Notes 6.05% due 2034	3,000,000,000	30,717,515
2			14,640,000 D
3	Senior Notes 5.80% due 2037	700,000,000	6,807,234
4			3,822,000 D
5	Senior Notes 5.80% due 2037	250,000,000	2,562,097
6			3,862,500 D
7	Senior Notes 6.35% due 2038	400,000,000	3,943,976
8			568,000 D
9	Senior Notes 6.25% due 2039	550,000,000	5,145,853
10			6,814,500 D
11	Senior Notes 5.40% due 2040	550,000,000	5,435,842
12			7,815,500 D
13	Senior Notes 5.40% due 2040	250,000,000	2,459,767
14			6,252,500 D
15	Senior Notes 4.50% due 2041	250,000,000	2,576,302
16			862,500 D
17	Senior Notes 4.45% due 2042	400,000,000	4,062,665
18			2,036,000 D
19	Senior Notes 3.75% due 2042	350,000,000	3,632,775
20			311,500 D
21	Senior Notes 4.60% due 2043	375,000,000	3,768,714
22			303,750 D
23	Senior Notes 5.125% due 2043	500,000,000	5,099,524
24			765,000 D
25	Senior Notes 4.75% due 2044	450,000,000	4,685,301
26			1,921,500 D
27	Senior Notes 4.75% due 2044	225,000,000	2,298,853
28			-13,594,500 P
29	Senior Notes 4.30% due 2045	500,000,000	5,051,799
30			5,745,000 D
31	Senior Notes 4.30% due 2045	100,000,000	1,092,707
32			5,231,000 D
33	TOTAL	19,887,100,000	273,179,138

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Senior Notes 4.25% due 2046	450,000,000	4,859,582
2			8,415,000 D
3	Senior Notes 4.00% due 2046	400,000,000	4,345,973
4			7,344,000 D
5	Senior Notes 4.00% due 2046	200,000,000	2,102,746
6			4,136,000 D
7	Senior Notes 3.95% due 2047	850,000,000	8,803,613
8			3,706,000 D
9	Pollution Control Bonds 1996 Series C, Various	200,000,000	1,001,412
10	Pollution Control Bonds 1996 Series E Various	165,000,000	927,332
11	Pollution Control Bonds 1996 Series F Various	100,000,000	556,667
12	Pollution Control Bonds 1997 Series B Various	148,550,000	886,179
13	Pollution Control Bonds 2008 Series F, 1.75%	50,000,000	164,224
14	Pollution Control Bonds 2009 Series A, Various	74,275,000	403,242
15	Pollution Control Bonds 2009 Series B, Various	74,275,000	403,242
16	Pollution Control Bonds 2010 Series E, 1.75%	50,000,000	328,903
17	subtotal	18,387,100,000	263,991,638
18			
19	Debtor-In-Possession Credit Facility - Term Loan, Various	1,500,000,000	9,187,500
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	19,887,100,000	273,179,138

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.
9/15/2010	10/1/2020	9/15/2010	10/1/2020	550,000,000	14,784,989	1
						2
11/18/2010	10/1/2020	11/18/2020	10/1/2020	250,000,000	6,720,450	3
						4
5/13/2011	5/15/2021	5/13/2011	5/15/2021	300,000,000	8,219,934	5
						6
9/12/2011	9/15/2021	9/12/2011	9/15/2021	250,000,000	6,675,570	7
						8
8/16/2012	8/15/2022	8/16/2012	8/15/2022	400,000,000	10,423,080	9
						10
6/14/2013	6/15/2023	6/14/2013	6/15/2023	375,000,000	12,232,146	11
						12
8/6/2018	8/1/2023	8/6/2018	8/1/2023	500,000,000	21,650,246	13
						14
11/12/2013	11/15/2023	11/12/2013	11/15/2023	300,000,000	11,634,296	15
						16
2/21/2014	2/15/2024	2/21/2014	2/15/2024	450,000,000	17,140,859	17
						18
8/18/2014	8/15/2024	8/18/2014	8/15/2024	350,000,000	12,069,982	19
						20
6/12/2015	6/15/2025	6/12/2015	6/15/2025	400,000,000	14,055,231	21
						22
11/5/2015	6/15/2025	11/5/2015	6/15/2025	200,000,000	7,027,615	23
						24
3/1/2016	3/1/2026	3/1/2016	3/1/2026	600,000,000	17,897,966	25
						26
3/10/2017	3/15/2027	3/10/2017	3/15/2027	400,000,000	13,349,529	27
						28
11/29/2017	12/1/2027	11/29/2017	12/1/2027	1,150,000,000	38,136,075	29
						30
8/6/2018	8/1/2028	8/6/2018	8/1/2028	300,000,000	14,237,479	31
						32
				19,887,100,000	677,880,030	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.
3/23/2004	3/1/2034	3/23/2004	3/1/2034	3,000,000,000	87,555,594	1
						2
3/13/2007	3/1/2037	3/13/2007	3/1/2037	700,000,000	20,276,343	3
						4
4/1/2010	3/1/2037	4/1/2010	3/1/2037	250,000,000	7,241,551	5
						6
3/3/2008	2/15/2038	3/3/2008	2/15/2038	400,000,000	11,806,160	7
						8
3/6/2009	3/1/2039	3/6/2009	3/1/2039	550,000,000	16,148,216	9
						10
11/18/2009	1/15/2040	11/18/2009	1/15/2040	550,000,000	15,829,344	11
						12
11/18/2010	1/15/2040	11/18/2010	1/15/2040	250,000,000	7,195,156	13
						14
12/1/2011	12/15/2041	12/1/2011	12/15/2041	250,000,000	11,307,062	15
						16
4/16/2012	4/15/2042	4/16/2012	4/15/2042	400,000,000	18,011,031	17
						18
8/16/2012	8/15/2042	8/16/2012	8/15/2042	350,000,000	13,331,779	19
						20
6/14/2013	6/15/2043	6/14/2013	6/15/2043	375,000,000	17,339,440	21
						22
11/12/2013	11/15/2043	11/12/2013	11/15/2043	500,000,000	14,061,647	23
						24
2/21/2014	2/15/2044	2/21/2014	2/15/2044	450,000,000	21,801,557	25
						26
8/18/2014	2/15/2044	8/18/2014	2/15/2044	225,000,000	10,900,778	27
						28
11/6/2014	3/15/2045	11/6/2014	3/15/2045	500,000,000	21,817,355	29
						30
6/12/2015	3/15/2045	6/12/2015	3/15/2045	100,000,000	4,363,471	31
						32
				19,887,100,000	677,880,030	33

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
11/5/2015	3/15/2046	11/5/2015	3/15/2046	450,000,000	19,404,015	1
						2
12/1/2016	12/1/2046	12/1/2016	12/1/2046	400,000,000	16,095,091	3
						4
3/10/2017	12/1/2046	3/10/2017	12/1/2046	200,000,000	8,047,546	5
						6
11/29/2017	12/1/2047	11/29/2017	12/1/2047	850,000,000	33,772,049	7
						8
5/23/1996	11/1/2026	5/23/1996	11/1/2026	200,000,000	5,109,770	9
5/23/1996	11/1/2026	5/23/1996	11/1/2026	165,000,000	4,210,184	10
5/23/1996	11/1/2026	5/23/1996	11/1/2026	100,000,000	2,552,017	11
9/16/1997	11/1/2026	9/16/1997	11/1/2026	148,550,000	3,790,441	12
6/15/2017	11/1/2026	6/15/2017	11/1/2026	50,000,000	1,265,701	13
9/1/2009	11/1/2026	9/1/2009	11/1/2026	74,275,000	1,896,208	14
9/1/2009	11/1/2026	9/1/2009	11/1/2026	74,275,000	1,896,208	15
6/15/2017	11/1/2026	6/15/2017	11/1/2026	50,000,000	1,265,701	16
				18,387,100,000	624,546,862	17
						18
4/3/2019	12/31/2020	N/A	N/A	1,500,000,000	53,333,168	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				19,887,100,000	677,880,030	33

Schedule Page: 256.2 Line No.: 17 Column: c

Items included under column (c) represent original issuance expenses, discounts, and premiums 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: 256.2 Line No.: 17 Column: i

Interest expense is different from prior year. PG&E filed for bankruptcy protection (Chapter 11) on January 29, 2019 and various rates were utilized to calculate interest as noted below.

Utility Long-Term Senior Notes
Interest prior to bankruptcy (pre-petition)from January 1, 2019 through January 28, 2019 was calculated using contractual rates. Interest subsequent to bankruptcy (post-petition) from January 29, 2019 through December 31, 2019 was calculated using Federal Judgement rate of 2.59%. These are noted with symbol (A) below.

Utility Funded Debt
Interest prior to bankruptcy (pre-petition) was calculated using variable rates. Interest subsequent to bankruptcy (post-petition) was calculated using Federal Judgement rate of 2.59%. These are noted with symbol (B) below.

Utility Reinstated Senior Notes
Interest was calculated using contractual rates. These are noted with symbol (C) below.

Symbol	Description	Principal	Rate
(A)	Senior Notes 3.50% due 2020	550,000,000	various
(A)	Senior Notes 3.50% due 2020	250,000,000	various
(A)	Senior Notes 4.25% due 2021	300,000,000	various
(A)	Senior Notes 3.25% due 2021	250,000,000	various
(A)	Senior Notes 2.45% due 2022	400,000,000	various
(C)	Senior Notes 3.25% due 2023	375,000,000	3.25%
(C)	Senior Notes 4.25% due 2023	500,000,000	4.25%
(C)	Senior Notes 3.85% due 2023	300,000,000	3.85%
(C)	Senior Notes 3.75% due 2024	450,000,000	3.75%
(C)	Senior Notes 3.40% due 2024	350,000,000	3.40%
(C)	Senior Notes 3.50% due 2025	400,000,000	3.50%
(C)	Senior Notes 3.50% due 2025	200,000,000	3.50%
(C)	Senior Notes 2.95% due 2026	600,000,000	2.95%
(C)	Senior Notes 3.30% due 2027	400,000,000	3.30%
(C)	Senior Notes 3.30% due 2027	1,150,000,000	3.30%
(C)	Senior Notes 4.65% due 2028	300,000,000	4.65%
(A)	Senior Notes 6.05% due 2034	3,000,000,000	Various
(A)	Senior Notes 5.80% due 2037	700,000,000	Various
(A)	Senior Notes 5.80% due 2037	250,000,000	Various
(A)	Senior Notes 6.35% due 2038	400,000,000	Various
(A)	Senior Notes 6.25% due 2039	550,000,000	Various
(A)	Senior Notes 5.40% due 2040	550,000,000	Various
(A)	Senior Notes 5.40% due 2040	250,000,000	Various

(C)	Senior Notes 4.50% due 2041	250,000,000	4.50%
(C)	Senior Notes 4.45% due 2042	400,000,000	4.45%
(C)	Senior Notes 3.75% due 2042	350,000,000	3.75%
(C)	Senior Notes 4.60% due 2043	375,000,000	4.60%
(A)	Senior Notes 5.125% due 2043	500,000,000	Various
(C)	Senior Notes 4.75% due 2044	450,000,000	4.75%
(C)	Senior Notes 4.75% due 2044	225,000,000	4.75%
(C)	Senior Notes 4.30% due 2045	500,000,000	4.30%
(C)	Senior Notes 4.30% due 2045	100,000,000	4.30%
(C)	Senior Notes 4.25% due 2046	450,000,000	4.25%
(C)	Senior Notes 4.00% due 2046	400,000,000	4.00%
(C)	Senior Notes 4.00% due 2046	200,000,000	4.00%
(C)	Senior Notes 3.95% due 2047	850,000,000	3.95%
(B)	Pollution Control Bonds 1996 Series C	200,000,000	Various
(B)	Pollution Control Bonds 1996 Series E	165,000,000	Various
(B)	Pollution Control Bonds 1996 Series F	100,000,000	Various
(B)	Pollution Control Bonds 1997 Series B	148,550,000	Various
(A)	Pollution Control Bonds 2008 Series F	50,000,000	Various
(B)	Pollution Control Bonds 2009 Series A	74,275,000	Various
(B)	Pollution Control Bonds 2009 Series B	74,275,000	Various
(A)	Pollution Control Bonds 2010 Series E	50,000,000	Various

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

Issuance costs were recorded to amortization of debt discounts and expense (428).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	-7,621,767,673
2		
3		
4	Taxable Income Not Reported on Books	
5		249,881,325
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	-2,364,990,851
11	Provision for State Income Taxes	-1,042,268,748
12	Per attached schedule (See page 261-1)	13,133,600,662
13		
14	Income Recorded on Books Not Included in Return	
15	AFUDC - Equity and Debt	134,107,199
16	Balancing Accounts	1,439,262,201
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Per attached schedule (See page 261-1)	2,577,253,857
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-1,796,168,542
28	Show Computation of Tax:	
29	Tax at 21% for Electric, Water. Non-Utility, and Gas	-377,195,394
30	Other	
31	Add: Tax on FIN 48 Interest	509,245
32	Less: Research & Development Credits	-3,088,011
33	Less: Motor Vehicle Credit	-250,000
34	Reclass Tax Loss to Deferred	385,088,403
35	Loss of Dividend Paid Deduction from Specified Liability Loss	471,801
36	Subtotal Tax	5,536,044
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 12 Column: b

Annual Report of PACIFIC GAS AND ELECTRIC COMPANY
Year Ended December 31, 2019

Deductions recorded on books not deducted on return:			Tax Addback
Bad Debts			2,041,563
Bankruptcy Costs			131,204,648
Capitalized Interest			75,492,194
Depreciation adjustment			211,300,613
DIP Financing Fees			64,887,432
DOE Settlement			14,848,269
Earnings of Subsidiaries			75,543
Executive Compensation			446,417
Fossil Decommissioning			4,113,061
Gas Hedge Amortization			3,341,621
GHG Allowances			600,853,528
Loss on Reacquired Debt			16,208,293
Meals & Entertainment & Lobbying			12,485,500
NorCal Wildfires Reserve			11,235,651,732
Nuclear Decommissioning			14,300,567
Nuclear Fuel expense			112,531,507
Penalties			55,958,596
Plant Disallowance			577,859,578
	Total	$	13,133,600,662

Deductions on return not charged against book income:			Tax Deduct
Compensation Related Adjustments			(26,373,778)
Computer Software			(83,591,156)
DCPP Community Payment			(52,244,591)
Environmental Cleanup			(101,223,248)
Gas Stored Underground			(1,944,551)
Property Tax & State Income Tax			(279,795,563)
Repairs			(1,861,397,396)
Section 263A MSCM			(165,967,950)
Other			(4,715,625)
	Total	$	(2,577,253,857)

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

See footnote in row 12, column (b)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	4,655,630		116,994,366	112,455,914	
2	Federal - Taxes on Income	309,576,689		5,536,044	-172,319	-869,422
3	Federal - Unemployment	-54,167		1,071,904	1,063,137	
4	Federal - Decommisioning			42,681,366	42,681,366	
5						
6	SUBTOTAL FEDERAL	314,178,152		166,283,680	156,028,098	-869,422
7						
8	State - Taxes on Income	46,486,203		87,160,357	830	6,044,269
9	State - Unemployment	105,978		8,013,589	7,880,326	
10						
11	SUBTOTAL STATE TAXES	46,592,181		95,173,946	7,881,156	6,044,269
12						
13	Ad Valorem property	1,103		491,258,314	515,638,314	24,380,000
14	Other	-273,031		16,401,008	12,966,538	
15						
16	SUBTOTAL OTHER TAXES	-271,928		507,659,322	528,604,852	24,380,000
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	360,498,405		769,116,948	692,514,106	29,554,847

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
9,194,082		80,927,432			36,066,934	1
314,415,630		-20,429,813			25,965,857	2
-45,400		720,748			351,156	3
		42,681,366				4
						5
323,564,312		103,899,733			62,383,947	6
						7
139,689,999		85,600,295			1,560,062	8
239,241		5,388,337			2,625,252	9
						10
139,929,240		90,988,632			4,185,314	11
						12
1,103		357,552,250			133,706,064	13
3,161,439		11,215,479			5,185,529	14
						15
3,162,542		368,767,729			138,891,593	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
466,656,094		563,656,094			205,460,854	41

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

The following table is included to satisfy requirements for Form 1 and Form 2 reporting of this page:

	Gas (Account 408.1, 409.1) (a)	Non_utility (Account 408.2, 409.2) (b)	Total Other (c)
Federal - FICA	36,066,934	0	36,066,934
Federal - Taxes on Income	20,887,268	5,078,589	25,965,857
Federal - Unemployment	351,156	0	351,156
Total Federal taxes	57,305,358	5,078,589	62,383,947
State - Taxes on Income	82,431,668	-80,871,606	1,560,062
State - Unemployment	2,625,252	0	2,625,252
Total State	85,056,920	-80,871,606	4,185,314
Ad Valorem property	133,706,064	0	133,706,064
Other	5,185,529	0	5,185,529
Total Other	138,891,593	0	138,891,593

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

Adjustment primarily related to FIN 48

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

Adjustment primarily related to FIN 48

Schedule Page: 262 Line No.: 13 Column: f

Adjustment reflects a portion of property taxes paid on construction work in progress. The amount charged during the year was reduced and capitalized to certain assets under construction.

Schedule Page: 262 Line No.: 14 Column: a

Balances primarily includes City and County of San Francisco gross receipts and payroll taxes.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	88,672,899			411.5	4,600,291	
6							
7							
8	TOTAL	88,672,899				4,600,291	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	10%	19,710,984			411.5	898,490	
12							
13	TOTAL	19,710,984				898,490	
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
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	03/25/2020	End of 2019/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
84,072,608	18		5
			6
			7
84,072,608			8
			9
			10
18,812,494	22		11
			12
18,812,494			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			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	03/25/2020	End of 2019/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	167,009,151	143, 146, 45	52,829,319	70,713,033	184,892,865
2						
3	Deferred Cr - Electric Reserves	46,736,126	182, 232, 92	39,047	221,268	46,918,347
4						
5	Other	13,566,148	Various	23,753,675	20,524,364	10,336,837
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						
47	TOTAL	227,311,425		76,622,041	91,458,665	242,148,049

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

Activity includes ~$46 million of amortization. The deferred credit is amortized over 30 years.

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

"Other" consists of various other deferred credits amounts with balances of less than 5% of the year end balance (< 242,148,049 * 5% = 12,107,402).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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 Reg Asset	307	-307	
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	307	-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	-307	
18	Classification of TOTAL			
19	Federal Income Tax	307	-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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	4,921,376,827	39,169,571	-132,353,350
3	Gas	2,667,090,788	-218,785,265	11,564,908
4	Nonutility	385,320,059		
5	TOTAL (Enter Total of lines 2 thru 4)	7,973,787,674	-179,615,694	-120,788,442
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	7,973,787,674	-179,615,694	-120,788,442
10	Classification of TOTAL			
11	Federal Income Tax	6,219,630,419	-164,594,564	-75,048,182
12	State Income Tax	1,754,157,255	-15,021,130	-45,740,260
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (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
					330,516,361	5,423,416,109	2
					170,603,823	2,607,344,438	3
15,363,558			-31,400,495			432,084,112	4
15,363,558			-31,400,495		501,120,184	8,462,844,659	5
							6
							7
							8
15,363,558			-31,400,495		501,120,184	8,462,844,659	9
							10
10,510,221			-21,669,983		374,492,657	6,536,756,898	11
4,853,337			-9,730,512		126,627,527	1,926,087,761	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	34,736,952	-6,215,855	-2,718,722
4	Balancing Accounts	352,212,672	393,010,772	-16,765,941
5	Other	18,766,107		-634,414,839
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	405,715,731	386,794,917	-653,899,502
10	Gas			
11	Loss on Reacquired Debt	16,737,972	-2,229,641	-1,208,093
12	Balancing Accounts	217,825,071	2,239,324	17,810,944
13				
14	Other	-1,662,981		-8,834,300
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	232,900,062	9,683	7,768,551
18	Other	-21,499,068	-16,980	2
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	617,116,725	386,787,620	-646,130,949
20	Classification of TOTAL			
21	Federal Income Tax	425,533,912	264,596,312	-442,018,626
22	State Income Tax	191,582,813	122,191,308	-204,112,323
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						31,239,819	3
						761,989,385	4
						653,180,946	5
							6
							7
							8
						1,446,410,150	9
							10
						15,716,424	11
						202,253,451	12
							13
						7,171,319	14
							15
							16
						225,141,194	17
						-21,516,050	18
						1,650,035,294	19
							20
5,364	-1					1,132,154,215	21
-5,364	1					517,881,079	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	REGULATORY LIABILITY RETIREM	420,655,202	520	11,205,305	340,235,277	749,685,174
2	Amortization : INDEFINITE					
3	PROCUREMENT ENERGY EFFICIENCY BALANCING	205,456,538	400	355,270,250	210,521,687	60,707,975
4	Amortization : <12 MONTHS					
5	PUBL PURP PROG ENERGY EFFICIENCY BAL ACCT -	40,651,549	400	122,458,535	96,040,479	14,233,493
6	Amortization : <12 MONTHS					
7	PPCBA-Disadv Comm Single Family Solar Homes Subat		400	1,565,080	4,420,225	2,855,145
8	Amortization : <12 MONTHS					
9	MISCELLANEOUS GAS REG LIAB - CURRENT	40,901,957	495	130,974,540	95,731,205	5,658,622
10	Amortization : <12 MONTHS					
11	MISCELLANEOUS ELECTRIC REG LIAB - CURRENT	324,987,560	449	709,669,948	390,202,589	5,520,201
12	Amortization : < 12 MONTHS					
13	PPP SURCHARGE RDD - CURRENT	3,618,093	182.3	11,241,599	11,223,961	3,600,455
14	Amortization : < 12 MONTHS					
15	REG LIABILITY-MISC ELEC CURRENT -FERC INTEREST	74,835,875	400		4,113,957	78,949,832
16	Amortization : <12 MONTHS					
17	MISCELLANEOUS GAS REG LIAB - NONCURRENT	16,250,790	549	74,348,729	83,626,948	25,529,009
18	Amortization : >12 MONTHS					
19	MISCELLANEOUS ELECTRIC REG LIAB - NONCURRENT	549,992,589	549	1,814,038,085	1,897,438,273	633,392,777
20	Amortization : NO STATED					
21	NON CURRENT REG LIAB-CC8 SETTLEMENT	44,595,674	108	2,260,506		42,335,168
22	Amortization : 25YEARS					
23	TAMA - GAS	(101,289,339)	182.3	2,294,005		-103,583,344
24	Amortization : 2 YEARS					
25	SOLAR ON MULTIFAMILY AFFORDABLE HOUSING BAL	51,081,839	400	3,858,676	40,710,136	87,933,299
26	Amortization : < 12 MONTHS					
27	GAS PRICE RISK MANAGEMENT - CURRENT	453,004	807	14,839,644	15,721,965	1,335,325
28	Amortization : NO STATED					
29	ELECTRIC PRICE RISK MANAGEMENT - CURRENT	42,951,612	555	161,669,184	146,956,970	28,239,398
30	Amortization : NO STATED					
31	FAS 143 REGULATORY LIABILITY	(1,691,962,287)	VARIOUS	299,574,515	53,240,661	-1,938,296,141
32	Amortization : NO STATED					
33	FAS 143 REGULATORY LIABILITY-NUCLEAR DECOMM	2,729,721,355	128	376,658,725	819,626,731	3,172,689,361
34	Amortization : NO STATED					
35	FAS 143 REGULATORY LIABILITY	(145,886,152)	VARIOUS	3,068,420		-148,954,572
36	Amortization : NO STATED					
37	FAS 143 REGULATORY LIABILITY	168,864,234	228.4	5,896,406	312,205	163,280,033
38	Amortization : NO STATED					
39	FIN 47 REGULATORY LIABILITY	(704,862,800)	VARIOUS	463,390,181	294,997,482	-873,255,499
40	Amortization : NO STATED					
41	TOTAL	3,496,782,247		8,190,426,575	8,104,790,237	3,411,145,909

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	CALIFORNIA SOLAR INITIATIVE	61,619,361	400	18,043,672	14,313,674	57,889,363
2	Amortization : < 12 MONTHS					
3	DEMAND RESPONSE EXPENDITURES BALANCING	40,066,089	400	25,363,436	46,800,726	61,503,379
4	Amortization : NO STATED					
5	PPP ENERGY EFFICIENCY-GAS	2,483,897	400	917,231	322,797	1,889,463
6	Amortization : NO STATED					
7	PPP SURCHARGE ENERGY EFFICIENCY - GAS	(1,113,867)	400	97,833,983	110,728,650	11,780,800
8	Amortization : < 12 MONTHS					
9	PPP SURCHARGE LOW INCOME - GAS	(7,558,695)	400	59,993,964	121,915,807	54,363,148
10	Amortization : < 12 MONTHS					
11	GAS PPP SURCHARGE-RDD	(435,020)	400	12,124,289	12,367,561	-191,748
12	Amortization : < 12 MONTHS					
13	NON-TARIFFED PRODUCTS AND SVCS BA-ELECTRIC	575,743	182.3	2,731,144	2,726,658	571,257
14	Amortization : < 12 MONTHS					
15	NON-TARIFFED PRODUCTS AND SVCS BA-GAS	470,130	182.3	550,294	545,282	465,118
16	Amortization : < 12 MONTHS					
17	ON BILL FINANCING BALANCING ELECTRIC	42,871,180	930.2	26,665,417	14,043,407	30,249,170
18	Amortization : NO STATED					
19	ON BILL FINANCING BALANCING GAS	9,339,338	930.2	8,291,117	4,238,136	5,286,357
20	Amortization : NO STATED					
21	ELECTRIC PROGRAM INVESTMENT CHARGE	189,505,507	400	59,543,132	108,352,779	238,315,154
22	Amortization : NO STATED					
23	PROCUREMENT ENERGY EFFICIENCY	10,354,247	400	3,382,033	1,460,902	8,433,116
24	Amortization : NO STATED					
25	SELF GENERATION PROGRAM - ELECTRIC	220,814,981	400	21,945,605	65,004,021	263,873,397
26	Amortization : NO STATED					
27	SELF GENERATION PROGARM-GAS	43,802,309	400	4,817,328	14,163,425	53,148,406
28	Amortization : NO STATED					
29	PPP (PPPLIBA)-GAS	77,256,947	400	107,097,905	61,075,514	31,234,556
30	Amortization : < 12 MONTHS					
31	PPP (PPPLIBA)-ELECTRIC	173,030,162	400	114,384,860	134,753,944	193,399,246
32	Amortization : < 12 MONTHS					
33	SW MARKETING, EDUCATION AND OUTREACH	1,600,819	400	12,546,769	15,935,227	4,989,277
34	Amortization : < 12 MONTHS					
35	SW MARKETING, EDUCATION AND OUTREACH	456,738	400	1,387,892	1,768,548	837,394
36	Amortization : < 12 MONTHS					
37	GPBA - GREENHOUSE GAS REVENUE SUBACCOUNT	259,167	400	125,956,782	131,941,175	6,243,560
38	Amortization : < 12 MONTHS					
39	GHGRBA - GREENHOUSE GAS REVENUE	(26,121,218)	400	465,480,065	516,639,586	25,038,303
40	Amortization : NO STATED					
41	TOTAL	3,496,782,247		8,190,426,575	8,104,790,237	3,411,145,909

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	CA ENERGY SYSTEMS FOR 21ST CENTURY B/A-ELEC -	(383,953)	182.3	1,552,276	2,682,204	745,975
2	Amortization : 5 YEARS					
3	GPBA - LOW CARBON FUELS STANDARD REVENUE	633,125	400	655,178	543,917	521,864
4	Amortization : < 12 MONTHS					
5	GHGRBA - LOW CARBON FUELS STANDARD REVENUE	62,665,786	400	38,423,744	132,301,274	156,543,316
6	Amortization : < 12 MONTHS					
7	ENGINEERING CRTICIAL ASSESSMENT BAL NC		182.3		15,878,253	15,878,253
8	Amortization : >12 MONTHS					
9	ELECT VEHICLE PRGM BA CURRENT	3,511,165	400	19,817,659	36,127,476	19,820,982
10	Amortization : < 12 MONTHS					
11	DISTRIBUTION RESOURCES PLAN DEMONSTRATION	939,939	400	976,036	1,067,912	1,031,815
12	Amortization : < 12 MONTHS					
13	RULE 20A BALANCING ACCOUNT (RBA) NONCURRENT	(6,637,555)	400	9,071,798	27,527,497	11,818,144
14	Amortization : > 12 MONTHS					
15	NGLAPBA - CURRENT		400	1,576,657	3,574,646	1,997,989
16	Amortization : < 12 MONTHS					
17	FAS143 RegLiab GUS LM and PC		228.4		17,762,400	17,762,400
18	Amortization : NO STATED					
19	ELECTRIC PRICE RISK MANAGEMENT - NONCURRENT	165,161,256	555	683,949,169	642,446,969	123,659,056
20	Amortization : NO STATED					
21	Miscellanous minor items	360,597,376	VARIOUS	1,701,064,807	1,340,659,119	191,688
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,496,782,247		8,190,426,575	8,104,790,237	3,411,145,909

Schedule Page: 278 Line No.: 31 Column: c

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

Schedule Page: 278 Line No.: 35 Column: c

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

Schedule Page: 278 Line No.: 39 Column: c

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

Schedule Page: 278.2 Line No.: 21 Column: c

Activity primarily related to FAS 109 REGULATORY LIABILITY, VEGETATION MANAGEMENT BA, DREBA OPERATIONS BALANCING ACCOUNT - CURRENT, ENGINEERING CRITICAL ASSESSMENT BAL ACCT-CURRENT and REGULATORY LIABILITY - INTEREST ON PREPETITION DEBT with offset to 400 and 449.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	4,846,946,484	5,051,462,029
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	5,862,972,960	6,141,452,151
5	Large (or Ind.) (See Instr. 4)	1,493,456,812	1,531,576,710
6	(444) Public Street and Highway Lighting	58,051,541	63,885,241
7	(445) Other Sales to Public Authorities	2,184,785	2,263,228
8	(446) Sales to Railroads and Railways	7,244,471	6,151,562
9	(448) Interdepartmental Sales	48,794,887	46,634,494
10	TOTAL Sales to Ultimate Consumers	12,319,651,940	12,843,425,415
11	(447) Sales for Resale	1,462,736,215	326,502,665
12	TOTAL Sales of Electricity	13,782,388,155	13,169,928,080
13	(Less) (449.1) Provision for Rate Refunds	-308,209,362	580,325,469
14	TOTAL Revenues Net of Prov. for Refunds	14,090,597,517	12,589,602,611
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,013,879	4,139,504
17	(451) Miscellaneous Service Revenues	8,400,066	9,362,424
18	(453) Sales of Water and Water Power	3,769,463	3,683,870
19	(454) Rent from Electric Property	83,262,832	104,364,515
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-252,724,684	-262,517,205
22	(456.1) Revenues from Transmission of Electricity of Others	2,558,524	1,845,837
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(400) Balancing Accounts	303,287,176	635,580,851
26	TOTAL Other Operating Revenues	151,567,256	496,459,796
27	TOTAL Electric Operating Revenues	14,242,164,773	13,086,062,407

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	No.
				1
27,513,436	27,485,186	4,845,484	4,798,731	2
				3
35,098,781	36,430,669	641,100	635,503	4
14,711,024	15,163,358	1,288	1,314	5
296,641	306,682	36,176	36,204	6
10,879	12,790	5	2	7
440,880	377,019	28	23	8
300,575	290,560			9
78,372,216	80,066,264	5,524,081	5,471,777	10
21,907,744	10,790,942			11
100,279,960	90,857,206	5,524,081	5,471,777	12
				13
100,279,960	90,857,206	5,524,081	5,471,777	14

Line 12, column (b) includes $ -39,025,952 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 $367,368,862 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 $410,485,871 which was deducted from Line 21 below.

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

This consists of:

1	NSF fees and rent charges to customers' refundable deposits	1,700,170
2	NRD Revenue	1,822,179
3	MLX billings to electric residential customers	3,246,059
4	MLX billings to electric non-residential customers	954,594
5	Reimbursable third-party labor requested on behalf of customers	677,064
	Total	8,400,066

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

This consists of:

1	NSF fees and rent charges to customers' refundable deposits	1,510,591
2	NRD Revenue	2,501,467
3	MLX billings to electric residential customers	3,271,478
4	MLX billings to electric non-residential customers	927,612
5	Reimbursable third-party labor requested on behalf of customers	1,151,276
	Total	9,362,424

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

This consists of :

Unbilled revenues	(39,025,952)
Reimbursement to the Utility for costs spent on customer projects	30,211,138
Reimbursement to the Utility for costs spent on customer billing	12,843,596
Reimbursement fees paid to the CPUC based on sales	(42,640,694)
Employee transfer fees	185,885
Other revenue-damage claim	1,255,339
Recreational Facilities Revenue	1,085,671
Revenue assigned - base	(24,165,208)
Pass-through franchise fees and uncollectible revenue	24,165,208
Transition Cost Revenue Account for non-bypassable charges	38,034,266
Fees for utility energy service contracts	52,451,511
Other electric revenues not classified elsewhere	59,451,590

MCI rights of way	650,161
DWR	(367,368,862)
Miscellaneous (items under $250,000)	141,667
Total	(252,724,684)

The DWR revenues of $367,368,862 represents amount passed through to the DWR. The Utility acts as a pass-through entity for DWR charges collected from the Utility's customers. Although charges for the DWR are included in total electric revenues, the Utility deducts pass through amounts from electric revenues. These pass-through revenues are excluded from the Utility's electric revenues in its Statement of Income.

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

This consists of:

Unbilled revenues	(1,586,893)
Reimbursement to the Utility for costs spent on customer projects	26,889,727
Reimbursement to the Utility for costs spent on customer billing	7,448,792
Reimbursement fees paid to the CPUC based on sales	(36,570,942)
Employee transfer fees	341,127
Other revenue-damage claim	2,321,285
Recreational Facilities Revenue	1,402,622
Revenue assigned - base	(23,988,441)
Pass-through franchise fees and uncollectible revenue	23,988,441
Transition Cost Revenue Account for non-bypassable charges	38,531,280
Fees for utility energy service contracts	51,290,247
Other electric revenues not classified elsewhere	57,148,118
MCI rights of way	691,661
DWR	(410,485,871)
Miscellaneous (items under $250,000)	61,641
Total	(262,517,206)

The DWR revenues of $410,485,871 represents amount passed through to the DWR. The Utility acts as a pass-through entity for DWR charges collected from the Utility's customers. Although charges for the DWR are included in total electric revenues, the Utility deducts pass through amounts from electric revenues. These pass-through revenues are excluded from the Utility's electric revenues in its Statement of Income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	16,979,014	3,289,082,936	3,180,969	5,338	0.1937
3	EL1 Residential Care Program S	6,437,417	780,560,540	1,089,504	5,909	0.1213
4	E6 Residential Time-of-Use Servic	408,995	82,797,487	84,842	4,821	0.2024
5	EL6 Residential Care Time-of-U	33,560	4,241,462	5,795	5,791	0.1264
6	E7 Time-of-Use		-142			
7	EL7 Residential Care Program T	-1	-151			0.1510
8	E8 Seasonal Service Option		-116			
9	ETOUA Residential Time-of-Use Ser	548,793	124,927,060	175,836	3,121	0.2276
10	EL-TOUA Residential Care Time-of-	102,025	13,009,721	26,602	3,835	0.1275
11	ETOUB Residential Time-of-Use Ser	812,639	173,460,890	71,819	11,315	0.2135
12	EL-TOUB Residential Care Time-of-	132,586	17,056,264	13,566	9,773	0.1286
13	ETOUC Residential Time-of-Use Ser	608,075	134,865,863	101,421	5,996	0.2218
14	EL-TOUC Residential Care Time-of-	93,637	11,645,870	17,916	5,226	0.1244
15	EA9 Experimental TOU Service for		1			
16	ECLSD		316			
17	EVA Residential TOU Service for P	658,333	107,588,410	54,730	12,029	0.1634
18	EVB Residential TOU Service for P	1,250	163,477	368	3,397	0.1308
19	EV2A Residential TOU Service for	32,722	5,015,876	2,929	11,172	0.1533
20	EM Master-Metered Multi-family Se	209,829	36,537,505	15,653	13,405	0.1741
21	EML Multifamily CARE Program - Ma	25,806	2,594,179	170	151,800	0.1005
22	EMTOU Residential Time of Use Ser	779	632,415	435	1,791	0.8118
23	ES Multi-family Service	23,833	3,569,654	278	85,730	0.1498
24	ESL Multifamily CARE Program Serv	25,949	3,754,590	276	94,018	0.1447
25	ESR RV Park and Residential Marin	2,606	447,856	35	74,457	0.1719
26	ESRL RV Park and Residential Mari	9,547	1,642,812	84	113,655	0.1721
27	ET Mobilehome Park Service	15,121	2,448,059	271	55,797	0.1619
28	ETL Low-Income Mobile Home	348,769	50,484,431	1,957	178,216	0.1448
29	MIS-RS		54			
30	SE1 Standby - Individually Metere	117	34,987	4	29,250	0.2990
31	SEM1 Standby - Master-Metered Mul	1,973	330,123	10	197,300	0.1673
32	STOUS Standby - TOU Secondary -		54,055	14		
33	UNCLASSIFIED	62				
34	Total Residential	27,513,436	4,846,946,484	4,845,484	5,678	0.1762
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	78,372,215	13,782,388,155	5,524,081	14,187	0.1759
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	78,372,215	13,782,388,155	5,524,081	14,187	0.1759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	1,192,120	217,233,804	50,741	23,494	0.1822
3	A1F Small General Service	71,656	15,497,648	17,463	4,103	0.2163
4	A1X Small General Service	5,616,606	1,136,241,724	369,358	15,206	0.2023
5	A15 Small General Service	410	222,783	378	1,085	0.5434
6	A6 Time-of-Use	1,243,465	248,232,535	26,548	46,838	0.1996
7	A10 Medium General	8,306,895	1,371,461,137	43,148	192,521	0.1651
8	E19 500 to 999 Kw Demand	13,407,235	1,732,414,541	28,572	469,244	0.1292
9	E20 1000 Kw Demand or More	12,870,563	1,263,556,943	998	12,896,356	0.0982
10	E37 1000 Kw Demand or More	100	8,080			0.0808
11	AG1 Agricultural Power	64,884	19,735,980	4,444	14,600	0.3042
12	AG4 TOU Agricultural Power	997,479	321,028,144	55,918	17,838	0.3218
13	AG5 Large TOU Agricultural Power	3,970,752	749,363,046	27,244	145,748	0.1887
14	AGICE Agricultural Internal Combu	18	4,180			0.2322
15	AGR Split-Wk TOU Agricultural Pow	27,826	8,781,318	1,830	15,205	0.3156
16	AGV Short-Pk TOU Agricultural Pow	23,237	6,385,142	1,229	18,907	0.2748
17	B1 Small General Service	4,220	838,572	474	8,903	0.1987
18	B6 Small General Time-of-Use Serv	386	68,678	24	16,083	0.1779
19	B10 Medium General Demand	3,534	602,721	30	117,800	0.1705
20	B19 Medium Demand Metered TOU	3,895	506,552	20	194,750	0.1301
21	B20 Service to Customers with Max	774	77,278			0.0998
22	MIS-RS		11,855			
23	OL1 Outdoor Area Lighting Service	8,221	2,735,624	13,105	627	0.3328
24	SA1 Standby & General Service	-1,546	13,711	5	-309,200	-0.0089
25	SA6 Standby & Small TOU	-7,808	1,289,608	18	-433,778	-0.1652
26	SA10 Standby & Alt. Rate for Med-	14,928	2,102,564	22	678,545	0.1408
27	SE19 Standby & 500 to 999 Kw	106,923	16,259,804	75	1,425,640	0.1521
28	SE20 Standby & 1000 Kw Demand	1,438,370	160,511,527	89	16,161,461	0.1116
29	STOUP Standby - TOU Primary	-4,148	10,773,565	254	-16,331	-2.5973
30	STOUS Standby - TOU Secondary -	1,456	2,276,493	150	9,707	1.5635
31	STOUT Standby - TOU Transformer	438,744	67,196,150	249	1,762,024	0.1532
32	UNCLASSIFIED	8,609	998,065	2	4,304,500	0.1159
33						
34						
35						
36	Total Commercial and Industrial	49,809,804	7,356,429,772	642,388	77,539	0.1477
37						
38						
39						
40						
41	TOTAL Billed	78,372,215	13,782,388,155	5,524,081	14,187	0.1759
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	78,372,215	13,782,388,155	5,524,081	14,187	0.1759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6	444 Public Street and Highway Lig					
7	LS1-A Utility-Owned Street & High	10,955	6,877,790	5,221	2,098	0.6278
8	LS1-B Utility-Owned Street & High	7	2,412	2	3,500	0.3446
9	LS1-C Utility-Owned Street & High	4,378	2,286,715	556	7,874	0.5223
10	LS1-D Utility-Owned Street & High	7,777	3,549,077	1,067	7,289	0.4564
11	LS1-E Utility-Owned Street & High	8,170	6,698,677	1,794	4,554	0.8199
12	LS1-F Utility-Owned Street & High	3,743	2,188,828	1,604	2,334	0.5848
13	LS2-A Customer-Owned Street & Hig	207,317	26,313,718	9,553	21,702	0.1269
14	LS2-C Customer-Owned Street & Hig	3,137	702,635	392	8,003	0.2240
15	LS3 Cust-Owned Street & Highway L	7,741	1,141,662	1,463	5,291	0.1475
16	LS3-F Cust-Owned Street & Highway	4,069	668,373	2,191	1,857	0.1643
17	TC1 Traffic Control Service	38,146	7,378,986	11,751	3,246	0.1934
18	TC1F Traffic Control Service	1,201	242,668	582	2,064	0.2021
19						
20	Total Public Street and Highway	296,641	58,051,541	36,176	8,200	0.1957
21						
22	445 Other Sales to Public Authori					
23	Special Contracts	10,879	2,184,785	5	2,175,800	0.2008
24	Total Other Sales to Public Aut	10,879	2,184,785	5	2,175,800	0.2008
25						
26	446 Sales to Railroads and Railwa					
27	Special Contracts	440,880	7,244,471	28	15,745,714	0.0164
28	Total Sales to Railroads and Ra	440,880	7,244,471	28	15,745,714	0.0164
29						
30	447 Sales for Resale					
31	Special Contracts		1,462,736,215			
32	Total Sales for Resale		1,462,736,215			
33						
34	448 Interdepartmental Sales	300,575	48,794,887			0.1623
35	Total Interdepartmental Sales	300,575	48,794,887			0.1623
36						
37						
38						
39						
40						
41	TOTAL Billed	78,372,215	13,782,388,155	5,524,081	14,187	0.1759
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	78,372,215	13,782,388,155	5,524,081	14,187	0.1759

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RQ Sales:					
2	Silicon Valley Power	RQ	248	0.4	17.7	17.7
3	California Independent System Operator	RQ	6	N/A	N/A	N/A
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
					2
21,907,744		586,377,238	876,358,977	1,462,736,215	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
21,907,744	0	586,377,238	876,358,977	1,462,736,215	
0	0	0	0	0	
21,907,744	**0**	**586,377,238**	**876,358,977**	**1,462,736,215**	

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

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

The Rate Schedule for Grizzly was changed in FERC Docket No. ER17-1752-000.

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

Represents amounts included in ISO Settlement Statement on page 397.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	6,129	55,323
5	(501) Fuel	204,525,672	207,064,898
6	(502) Steam Expenses	10,488	16,174
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	66,148	388,314
11	(507) Rents		
12	(509) Allowances	33,701,353	35,626,112
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	238,309,790	243,150,821
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	39,355	129,982
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant	2,192,474	1,478,290
18	(513) Maintenance of Electric Plant	10,822,436	19,232,845
19	(514) Maintenance of Miscellaneous Steam Plant	5,534,351	1,691,099
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	18,588,616	22,532,216
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	256,898,406	265,683,037
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	4,915,613	4,025,966
25	(518) Fuel	113,567,860	129,114,087
26	(519) Coolants and Water	35,186,370	37,292,499
27	(520) Steam Expenses	41,818,534	38,815,499
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	4,021,766	1,867,685
31	(524) Miscellaneous Nuclear Power Expenses	222,449,476	338,894,022
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	421,959,619	550,009,758
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	2,623,727	2,782,594
36	(529) Maintenance of Structures	4,274,664	3,442,055
37	(530) Maintenance of Reactor Plant Equipment	31,444,584	26,816,759
38	(531) Maintenance of Electric Plant	42,240,924	36,172,375
39	(532) Maintenance of Miscellaneous Nuclear Plant	115,868,215	-83,619,837
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	196,452,114	-14,406,054
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	618,411,733	535,603,704
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	439,376	448,001
45	(536) Water for Power	1,662,236	2,190,879
46	(537) Hydraulic Expenses	2,170,419	1,449,339
47	(538) Electric Expenses	25,142,375	26,715,623
48	(539) Miscellaneous Hydraulic Power Generation Expenses	68,497,209	60,364,066
49	(540) Rents	803,141	796,739
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	98,714,756	91,964,647
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,210,247	1,648,157
54	(542) Maintenance of Structures	3,991,198	2,122,736
55	(543) Maintenance of Reservoirs, Dams, and Waterways	28,368,557	23,269,718
56	(544) Maintenance of Electric Plant	21,946,833	19,942,182
57	(545) Maintenance of Miscellaneous Hydraulic Plant	7,060,275	5,923,153
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	62,577,110	52,905,946
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	161,291,866	144,870,593

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	202,870	593,029
63	(547) Fuel		
64	(548) Generation Expenses	10,779,037	10,644,381
65	(549) Miscellaneous Other Power Generation Expenses	4,027,747	939,016
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	15,009,654	12,176,426
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	46,074	161,732
70	(552) Maintenance of Structures	2,528,626	2,848,377
71	(553) Maintenance of Generating and Electric Plant	3,993,115	7,166,782
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,501,125	5,692,471
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	8,068,940	15,869,362
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	23,078,594	28,045,788
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	4,058,377,103	3,496,844,586
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	174,226,755	314,924,584
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,232,603,858	3,811,769,170
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,292,284,457	4,785,972,292
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,397,496	5,738,383
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	34,154,856	32,099,953
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	20,057,993	23,000,855
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	7,710,341	8,859,349
93	(562) Station Expenses	8,684,009	7,988,173
94	(563) Overhead Lines Expenses	78,078,057	13,924,543
95	(564) Underground Lines Expenses	235,377	180,771
96	(565) Transmission of Electricity by Others	1,014,722	949,485
97	(566) Miscellaneous Transmission Expenses	183,864,519	99,690,874
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	340,197,370	192,432,386
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,336,831	1,184,331
102	(569) Maintenance of Structures	1,025,132	703,947
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	41,789,620	22,519,226
108	(571) Maintenance of Overhead Lines	608,246,266	129,824,961
109	(572) Maintenance of Underground Lines	1,787,030	1,699,411
110	(573) Maintenance of Miscellaneous Transmission Plant	493,625	725,484
111	TOTAL Maintenance (Total of lines 101 thru 110)	654,678,504	156,657,360
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	994,875,874	349,089,746

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	13,723,909	13,832,809
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	13,723,909	13,832,809
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	13,723,909	13,832,809
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	6,014,879	2,428,597
135	(581) Load Dispatching		
136	(582) Station Expenses	3,079,056	2,238,385
137	(583) Overhead Line Expenses	41,788,851	30,749,818
138	(584) Underground Line Expenses	47,446,039	30,333,882
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	1,073,918	1,646,498
141	(587) Customer Installations Expenses	14,723,638	15,512,197
142	(588) Miscellaneous Expenses	414,577,885	240,620,319
143	(589) Rents	569,576	666,513
144	TOTAL Operation (Enter Total of lines 134 thru 143)	529,273,842	324,196,209
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	6,211,857	1,165,788
147	(591) Maintenance of Structures	1,132,501	2,824,259
148	(592) Maintenance of Station Equipment	48,729,079	26,624,095
149	(593) Maintenance of Overhead Lines	775,894,931	751,642,765
150	(594) Maintenance of Underground Lines	49,179,380	38,420,026
151	(595) Maintenance of Line Transformers	1,509,530	1,817,300
152	(596) Maintenance of Street Lighting and Signal Systems	1,543,961	1,738,254
153	(597) Maintenance of Meters	8,695,292	7,806,252
154	(598) Maintenance of Miscellaneous Distribution Plant	1,585,045	733,849
155	TOTAL Maintenance (Total of lines 146 thru 154)	894,481,576	832,772,588
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	1,423,755,418	1,156,968,797
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	6,778,388	6,941,089
160	(902) Meter Reading Expenses	6,653,089	5,761,047
161	(903) Customer Records and Collection Expenses	204,050,050	163,431,605
162	(904) Uncollectible Accounts	34,941,999	26,821,384
163	(905) Miscellaneous Customer Accounts Expenses	1,308,400	-675,994
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	253,731,926	202,279,131

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	462,729,169	442,540,037
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	162,912	404,461
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	462,892,081	442,944,498
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,039,813	961,730
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,039,813	961,730
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	398,482,342	216,675,790
182	(921) Office Supplies and Expenses	73,887,712	-10,731,390
183	(Less) (922) Administrative Expenses Transferred-Credit	103,181,563	36,224,106
184	(923) Outside Services Employed	568,349,816	276,922,321
185	(924) Property Insurance	13,751,290	10,118,251
186	(925) Injuries and Damages	11,371,690,540	12,202,690,726
187	(926) Employee Pensions and Benefits	357,000,223	273,560,929
188	(927) Franchise Requirements	89,389,579	89,640,572
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	23,019,768	11,017,410
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	12,792,389,707	13,033,670,503
195	Maintenance		
196	(935) Maintenance of General Plant	4,229,193	4,725,363
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	12,796,618,900	13,038,395,866
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	21,238,922,378	19,990,444,869

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

Of the year end balance, $124,788 relates to energy storage operation per FERC Order 784.

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

Of the year end balance,($220,207)relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: b

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

Schedule Page: 320 Line No.: 107 Column: c

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

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

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

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

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

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

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

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

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

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

Of the year end balance, $614,883 relates to energy storage operation per FERC Order 784.

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

Of the year end balance, $185,192 relates to energy storage operation per FERC Order 784.

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	QUALIFYING FACILITIES (QF's)			0.00000	0.00000	
2	RENEWABLES:			0.00000	0.00000	
3	BIOGAS - CITY OF WATSONVILLE	LU		0.00000	0.14110	N/A
4	MONTEREY REGIONAL WATER	LU		0.00000	0.21640	N/A
5	BIOMASS - THERMAL ENERGY DEV.	LU		0.00000	0.00000	N/A
6	HYDRO - JOHN NEERHOUT JR.	LU		0.00000	0.00660	N/A
7	GANSNER HYDRO	LU		0.00000	0.09720	N/A
8	FIVE BEARS HYDROELECTRIC	LU		0.00000	0.32860	N/A
9	HYPOWER INC.	LU		0.00000	8.85230	N/A
10	JAMES B. PETER	LU		0.00000	0.01460	N/A
11	JAMES CRANE HYDRO	LU		0.00000	0.00060	N/A
12	STS HYDROPOWER LTD KANAKA	LU		0.00000	0.00000	N/A
13	HYDRO SIERRA DEADWOOD CREEK	LU		0.00000	0.96260	N/A
14	EL DORADO MONTGOMERY CREEK	LU		0.00000	1.42140	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SNOW MOUNTAIN COVE	LU		0.00000	2.61600	N/A
2	SNOW MOUNTAIN BURNEY CREEK	LU		0.00000	1.71930	N/A
3	OLSEN POWER PARTNERS	LU		0.00000	2.71990	N/A
4	SNOW MT. PONDEROSA BAILEY CREEK	LU		0.00000	0.74950	N/A
5	NELSON CREEK POWER	LU		0.00000	0.06410	N/A
6	MALACHA HYDRO L.P.	LU		0.00000	16.02720	N/A
7	LOFTON RANCH	LU		0.00000	0.13610	N/A
8	HAT CREEK HEREFORD RANCH	LU		0.00000	0.02670	N/A
9	STEVE & BONNIE TETRICK	LU		0.00000	0.00000	N/A
10	EIF HAYPRESS LLC LWR	LU		0.00000	1.38410	N/A
11	EIF HAYPRESS LLC	LU		0.00000	3.06320	N/A
12	EIF HAYPRESS LLC MDL	LU		0.00000	1.79420	N/A
13	EAGLE HYDRO	LU		0.00000	0.00000	N/A
14	CHARCOAL RAVINE	LU		0.00000	0.00080	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SWISS AMERICA	LU		0.00000	0.03030	N/A
2	WRIGHT RANCH HYDROELECTRIC	LU		0.00000	0.00000	N/A
3	SCHAADS HYDRO	LU		0.00000	0.06660	N/A
4	ROCK CREEK WATER DISTRICT	LU		0.00000	0.16020	N/A
5	TOM BENNINGHOVEN	LU		0.00000	0.00000	N/A
6	OLCESE WATER DISTRICT	LU		0.00000	2.69330	N/A
7	ORANGE COVE IRRIGATION DISTRICT	LU		0.00000	0.46830	N/A
8	KINGS RIVER HYDRO	LU		0.00000	0.28160	N/A
9	ETIWANDA POWER PLANT	LU		0.00000	0.00000	N/A
10	SOLAR- VILLA SORRISO SOLAR	LU		0.00000	0.00010	N/A
11	WIND- DONALD R. CHENOWETH	LU		0.00000	0.00010	N/A
12	EDF RENEWABLE INC 70 MW C	LU		0.00000	0.00000	
13	EDF RENEWABLE INC 70 MW D	LU		240.00000	238.63180	N/A
14	COGEN - CROCKETT COGEN	LU		0.00000	8.20820	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	Average Monthly CP Demand (f)
1	PHILLIPS 66	LU		22.47000	2.19970	N/A
2	BERKELEY COGENERATION	LU		0.00000	0.00000	N/A
3	STANFORD ENERGY GROUP	LU		0.00000	0.64220	N/A
4	ECO SERVICES OPERATIONS LLC	LU		0.00000	0.01070	N/A
5	SATELLITE SENIOR HOMES	LU		0.00000	0.02290	N/A
6	HAYWARD AREA RECREATION AND PARK	LU		0.00000	10.89800	N/A
7	CHEVRON RICHMOND REFINERY	LU		0.00000	0.00130	N/A
8	ORINDA SENIOR VILLAGE	LU		0.00000	1.68370	N/A
9	SRI INTERNATIONAL	LU		0.00000	0.00000	N/A
10	ARDEN WOOD BENEVOLENT ASSOC.	LU		0.00000	0.00650	N/A
11	1080 CHESTNUT CORP.	LU		0.00000	0.00250	N/A
12	NIHONMACHI TERRACE	LU		0.00000	0.00470	N/A
13	GREATER VALLEJO RECREATION DIST.	LU		0.00000	0.00130	N/A
14	AIRPORT CLUB	LU		0.00000	0.00060	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SANTA CRUZ COUNTY WATER ST. JAIL	LU		0.00000	0.00000	N/A
2	CITY OF MILPITAS	LU		49.20000	8.23350	N/A
3	GREENLEAF UNIT 1	LU		49.20000	46.83970	N/A
4	GREENLEAF UNIT 2	LU		46.00000	40.17480	N/A
5	YUBA CITY COGEN	LU		0.00000	0.00000	N/A
6	YUBA CITY RACQUET CLUB	LU		111.00000	40.71820	N/A
7	CALPINE KING CITY COGEN	LU		0.00000	0.60330	N/A
8	FRITO-LAY COGEN	LU		0.00000	1.85950	N/A
9	FRITO-LAY COGEN	LU		33.00000	34.18460	N/A
10	FRITO-LAY COGEN QPA2	LU		34.50000	22.41180	N/A
11	FRESNO COGEN LP	LU		0.00000	3.79670	N/A
12	PE KES KINGSBURG LLC	LU		0.00000	3.67590	N/A
13	EOR- CHEVRON MCKITTRICK FHP	LU		0.00000	5.88120	N/A
14	CHEVRON USA TAFT/CADET	LU		0.00000	1.42080	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	CHEVRON USA CYMRIC	LU		0.00000	0.84910	N/A
2	AERA ENERGY SOUTH BELRIDGE	LU		0.00000	3.91620	N/A
3	AERA ENERGY SOUTH BELRIDGE	LU		17.75000	18.22770	N/A
4	AERA ENERGY SOUTH BELRIDGE QAA2	LU		0.00000	12.88210	N/A
5	CHEVRON USA COALINGA	LU		0.00000	5.22420	N/A
6	WESTERN POWER & STEAM INC	LU		0.00000	5.70240	N/A
7	BERRY PETROLEUM CO - TANNEHILL	LU		0.00000	15.76080	N/A
8	BERRY PETROLEUM CO - TANNEHILL	LU		0.00000	1.78500	N/A
9	CHEVRON USA INC SE KERN RIVER	LU		0.00000	2.47740	N/A
10	CHEVRON USA INC EASTRIDGE	LU		0.00000	0.00000	
11	AERA ENERGY LLC COALINGA	LU		0.00000	0.00000	
12	FREEPORT MCMORAN DOME	LU		0.00000	0.00000	
13						
14	BILATERALS			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	2018 REC Sales Oct-Dec Accrual			0.00000	0.00000	
2	2041 ALVARES			0.00000	0.00000	
3	2056 JARDINE			0.00000	0.00000	
4	2059 SCHERZ			0.00000	0.00000	
5	2065 ROGERS			0.00000	0.00000	
6	2081 TERZIAN			0.00000	0.00000	
7	2094 BUZZELLE PRISTINE SUN			0.00000	0.00000	
8	2096 COTTON PRISTINE SUN			0.00000	0.00000	
9	2097 HELTON PRISTINE SUN			0.00000	0.00000	
10	2102 CHRISTENSEN			0.00000	0.00000	
11	2103 HILL PRISTINE SUN			0.00000	0.00000	
12	2105 HART (Oroville Solar)			0.00000	0.00000	
13	2113 FITZJARRELL PRISTINE SUN			0.00000	0.00000	
14	2125 JARVIS PRISTINE SUN			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	2127 HARRIS			0.00000	0.00000	
2	2154 FOOTE (Oroville Solar)			0.00000	0.00000	
3	2158 STROING PRISTINE SUN			0.00000	0.00000	
4	2179 SMOTHERMAN			0.00000	0.00000	
5	2184 GRUBER (ENERPARC)			0.00000	0.00000	
6	2192 RAMIREZ (Oroville Solar)			0.00000	0.00000	
7	3 PHASES RA - BU			0.00000	0.00000	
8	3 PHASES RENEWABLES			0.00000	0.00000	
9	3 PHASES RENEWABLES INC			0.00000	0.00000	
10	ABEC #2 LLC			0.00000	0.00000	
11	ABEC #3 LLC			0.00000	0.00000	
12	ABEC #4 LLC			0.00000	0.00000	
13	ABEC BIDART OLD RIVER			0.00000	0.00000	
14	ABEC BIDART STOCKDALE			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AGUA CALIENTE SOLAR			0.00000	0.00000	
2	ALAMO SOLAR			0.00000	0.00000	
3	ALAMO SOLAR RAM 2			0.00000	0.00000	
4	ALGONQUIN SANGER - BU			0.00000	0.00000	
5	ALGONQUIN SANGER POWER LLC			0.00000	0.00000	
6	ALGONQUIN SKIC 20 SOLAR			0.00000	0.00000	
7	ALPAUGH 50 LLC			0.00000	0.00000	
8	ALPAUGH NORTH LLC			0.00000	0.00000	
9	ANGELS POWERHOUSE			0.00000	0.00000	
10	ANGELS POWERHOUSE (UTICA)			0.00000	0.00000	
11	APEX 646-460			0.00000	0.00000	
12	ARBUCKLE MOUNTAIN HYDRO			0.00000	0.00000	
13	ARLINGTON WIND POWER PROJECT			0.00000	0.00000	
14	ARLINGTON WIND RATTLESNAKE ROAD			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	ASPIRATION SOLAR G			0.00000	0.00000	
2	ATWELL ISLAND			0.00000	0.00000	
3	AV SOLAR RANCH ONE			0.00000	0.00000	
4	AV SOLAR RANCH ONE (Approve in Endur (			0.00000	0.00000	
5	AVANGRID RENEWABLES			0.00000	0.00000	
6	AVENAL SOLAR PROJECT A			0.00000	0.00000	
7	AVENAL SOLAR PROJECT B			0.00000	0.00000	
8	BADGER CREEK LIMITED			0.00000	0.00000	
9	BADGER CREEK LIMITED CHP RFO-2			0.00000	0.00000	
10	BAKER CREEK HYDROELECTRIC			0.00000	0.00000	
11	BAKERSFIELD 111 LLC			0.00000	0.00000	
12	BAKERSFIELD INDUSTRIAL 1			0.00000	0.00000	
13	BAKERSFIELD PV 1			0.00000	0.00000	
14	BAYSHORE SOLAR A			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	BAYSHORE SOLAR B			0.00000	0.00000	
2	BAYSHORE SOLAR C			0.00000	0.00000	
3	BEAR CREEK SOLAR LLC			0.00000	0.00000	
4	BEAR MOUNTAIN LIMITED			0.00000	0.00000	
5	BEAR MOUNTAIN LIMITED (2013 CHP			0.00000	0.00000	
6	BIG CREEK WATER WORKS			0.00000	0.00000	
7	BLACKSPRING RIDGE 1A			0.00000	0.00000	
8	BLACKSPRING RIDGE 1A - REC ONLY (no	Pa			0.00000	0.00000
9	BLACKSPRING RIDGE 1B			0.00000	0.00000	
10	BLACKSPRING RIDGE 1B - REC ONLY (no	Pa			0.00000	0.00000
11	BLACKWELL SOLAR			0.00000	0.00000	
12	BLAKE'S LANDING FARMS INC			0.00000	0.00000	
13	BONNEVILLE KLONDIKE IIIA S&F			0.00000	0.00000	
14	Bonneville Power Administration			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	BONNEVILLE POWER ADMINSTRATION			0.00000	0.00000	
2	BPA TSA			0.00000	0.00000	
3	BROWNS VALLEY IRRIGATION DIST.			0.00000	0.00000	
4	BUCKEYE HYDROELECTRIC PROJECT			0.00000	0.00000	
5	Burney Forest - BIOMASS			0.00000	0.00000	
6	Burney Forest - BIORAM			0.00000	0.00000	
7	CALAVERAS PUBLIC UTILI. DIST. 1			0.00000	0.00000	
8	CALAVERAS PUBLIC UTILI. DIST. 2			0.00000	0.00000	
9	CALAVERAS PUBLIC UTILI. DIST. 3			0.00000	0.00000	
10	CALIFORNIA FLATS SOLAR 150			0.00000	0.00000	
11	California Flats Solar Project			0.00000	0.00000	
12	CALPINE ENERGY - AGNEWS, INC			0.00000	0.00000	
13	CALPINE ENERGY EEI			0.00000	0.00000	
14	CALPINE ENERGY SERVICES REC 2019			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Calpine Energy Services, LP			0.00000	0.00000	
2	CALPINE GEYSERS (200/425 MW)			0.00000	0.00000	
3	CALPINE LOS ESTEROS			0.00000	0.00000	
4	CALPINE LOS ESTEROS UPGRADE			0.00000	0.00000	
5	CALPINE PEAKERS			0.00000	0.00000	
6	CALPINE RUSSELL CITY			0.00000	0.00000	
7	CALPINE RUSSELL CITY - COD JUNE 2010			0.00000	0.00000	
8	CALRENEW CLEANTECH			0.00000	0.00000	
9	CALRENEW-1 LLC			0.00000	0.00000	
10	CAMS DOUBLE C LIMITED			0.00000	0.00000	
11	CAMS HIGH SIERRA LIMITED			0.00000	0.00000	
12	CAMS KERN FRONT LIMITED			0.00000	0.00000	
13	CASTELANELLI BROS BIOGAS			0.00000	0.00000	
14	CASTOR SOLAR PROJECT			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CASTOR SOLAR PROJECT (Geen Light)			0.00000	0.00000	
2	CE of Montana (assoc w/2011 RA)			0.00000	0.00000	
3	CED CORCORAN SOLAR 3 LLC			0.00000	0.00000	
4	CED WHITE RIVER SOLAR 2, LLC			0.00000	0.00000	
5	CED WHITE RIVER SOLAR, LLC			0.00000	0.00000	
6	CEDAR FLAT (Hudson Power)			0.00000	0.00000	
7	CEDAR FLAT SHAMROCK			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 RAM 2			0.00000	0.00000	
11	CID SOLAR, LLC			0.00000	0.00000	
12	City of San Jos,			0.00000	0.00000	
13	CITY OF SAN JOSE REC 2019			0.00000	0.00000	
14	CITY OF VERNON			0.00000	0.00000	
	Total					

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	CLEAN PWR ALLIANCE			0.00000	0.00000	
2	CLEAN PWR ALLIANCE OF SOCAL			0.00000	0.00000	
3	CLEANPOWERSF			0.00000	0.00000	
4	CLOVER FLAT LFG			0.00000	0.00000	
5	CLOVER FLAT LFG (VISTA Corp)			0.00000	0.00000	
6	CLOVER LEAF			0.00000	0.00000	
7	CLOVER LEAF (Constantino)			0.00000	0.00000	
8	CLOVER LEAF SHAMROCK			0.00000	0.00000	
9	CLOVERDALE SOLAR 1 LLC			0.00000	0.00000	
10	COLUMBIA SOLAR ENERGY LLC			0.00000	0.00000	
11	COMMERCIAL ENERGY OF MT - BU			0.00000	0.00000	
12	CONOCOPHILLIPS WSPP			0.00000	0.00000	
13	COPPER MOUNTAIN 10			0.00000	0.00000	
14	COPPER MOUNTAIN 2 SEMPRA			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	COPPER MOUNTAIN SOLAR 2 (SEMPRA)			0.00000	0.00000	
2	COPPER MOUNTAIN SOLAR 48			0.00000	0.00000	
3	CORAM BRODIE WIND			0.00000	0.00000	
4	CORCORAN SOLAR			0.00000	0.00000	
5	CPSF - BU			0.00000	0.00000	
6	CUYAMA SOLAR			0.00000	0.00000	
7	Cuyama Solar Array			0.00000	0.00000	
8	Delano Land 1			0.00000	0.00000	
9	DELANO PV 1 LLC			0.00000	0.00000	
10	DESERT CENTER SOLAR FARM			0.00000	0.00000	
11	DIGGER CREEK HYDRO			0.00000	0.00000	
12	Direct Energy			0.00000	0.00000	
13	DIRECT ENERGY - BU			0.00000	0.00000	
14	DIRECT ENERGY 2018 REC SALE			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	DIRECT ENERGY 2019 REC SALE			0.00000	0.00000	
2	DIRECT ENERGY BUS			0.00000	0.00000	
3	DIRECT ENERGY BUS MKTG			0.00000	0.00000	
4	DIRECT ENERGY BUSINESS MARKETING			0.00000	0.00000	
5	DTE POTRERO HILL ENERGY PRODCERS			0.00000	0.00000	
6	DTE STOCKTON			0.00000	0.00000	
7	DTE SUNSHINE GAS LANDFILL			0.00000	0.00000	
8	DTE WOODLAND BIOMASS			0.00000	0.00000	
9	East Bay CE			0.00000	0.00000	
10	EAST BAY COMMUNITY 2019 REC SALE			0.00000	0.00000	
11	EAST BAY COMMUNITY ENERGY			0.00000	0.00000	
12	EAST BAY COMMUNITY ENERGY - BU			0.00000	0.00000	
13	EAST BAY COMMUNITY ENERGY AUTH			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	03/25/2020	End of 2019/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	ECOS ENERGY LLC KETTLEMAN SOLAR			0.00000	0.00000	
2	EDF Trading EEI			0.00000	0.00000	
3	EDF TRADING NORTH AMERICA 2019			0.00000	0.00000	
4	EIF PANOCHE (FIREBAUGH)			0.00000	0.00000	
5	EL DORADO IRRIGATION DISTRICT			0.00000	0.00000	
6	ENERPARC CA1 LLC			0.00000	0.00000	
7	EQUUS ENERGY BROKER			0.00000	0.00000	
8	ETIWANDA POWER PLANT			0.00000	0.00000	
9	EURUS AVENAL PARK LLC			0.00000	0.00000	
10	EURUS SAND DRAG LLC			0.00000	0.00000	
11	EURUS SUN CITY LLC			0.00000	0.00000	
12	Exelon			0.00000	0.00000	
13	EXELON GENERATION - BU			0.00000	0.00000	
14	EXELON GENERATION 2019			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	EXELON GENERATION COMPANY			0.00000	0.00000	
2	EXELON GENERATION WSPP			0.00000	0.00000	
3	FALL RIVER MILLS A ACHOMAWI			0.00000	0.00000	
4	FALL RIVER MILLS B AHJUMAWI			0.00000	0.00000	
5	FRESH AIR ENERGY IV SONORA 1			0.00000	0.00000	
6	FRESNO SOLAR SOUTH			0.00000	0.00000	
7	FRESNO SOLAR WEST			0.00000	0.00000	
8	GENESIS SOLAR ENERGY PROJECT			0.00000	0.00000	
9	GENESIS SOLAR, LLC			0.00000	0.00000	
10	GEYSERS 50/250/425 MW			0.00000	0.00000	
11	GLOBAL AMPERSAND CHOWCHILLA			0.00000	0.00000	
12	GLOBAL AMPERSAND EL NIDO			0.00000	0.00000	
13	GOOSE VALLEY FARMING, LLC			0.00000	0.00000	
14	GRASSHOPPER FLAT			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	GRASSHOPPER FLAT (EMMERSON) -			0.00000	0.00000	
2	GREEN LIGHT ENERGY SIRUIS SOLAR			0.00000	0.00000	
3	GREEN LIGHT MADERA 1			0.00000	0.00000	
4	GREEN LIGHT SIRIUS SOLAR			0.00000	0.00000	
5	GWF HANFORD			0.00000	0.00000	
6	GWF HANFORD 2013-2022			0.00000	0.00000	
7	GWF HENRIETTA			0.00000	0.00000	
8	GWF HENRIETTA 2013-2022			0.00000	0.00000	
9	GWF TRACY			0.00000	0.00000	
10	GWF TRACY REPOWERING PPA			0.00000	0.00000	
11	HALKIRK I WIND PROJECT			0.00000	0.00000	
12	HALKIRK I WIND PROJECT - REC ONLY (no	Pa			0.00000	0.00000
13	HATCHET RIDGE WIND LLC AR			0.00000	0.00000	
14	HENRIETTA SOLAR			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	HETCH HETCHY - BU			0.00000	0.00000	
2	HETCH HETCHY POWER CCSF			0.00000	0.00000	
3	HIGH PLAIN RANCH II			0.00000	0.00000	
4	HIGH PLAINS RANCH II			0.00000	0.00000	
5	HIGH PLAINS RANCH III			0.00000	0.00000	
6	HOLLISTER SOLAR ECOS ENERGY			0.00000	0.00000	
7	IBERDROLA KLONDIKE (AKA PPM			0.00000	0.00000	
8	IBERDROLA RENEWABLES (AKA PPM			0.00000	0.00000	
9	ICE Broker Agreement			0.00000	0.00000	
10	IMMODO LEMOORE			0.00000	0.00000	
11	IVANPAH UNIT 1			0.00000	0.00000	
12	IVANPAH UNIT 3			0.00000	0.00000	
13	JACKSON VALLEY IRRIGATION DIST			0.00000	0.00000	
14	KANSAS			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	KEKAWAKA CREEK HYDRO RAM 4			0.00000	0.00000	
2	KENT SOUTH - PV 2			0.00000	0.00000	
3	KERN RIVER COGEN			0.00000	0.00000	
4	KERN RIVER COGEN (KRCC)			0.00000	0.00000	
5	KINGSBURG 1 TULARE PV II LLC			0.00000	0.00000	
6	KINGSBURG 2 TULARE PV II LLC			0.00000	0.00000	
7	KINGSBURG 3 TULARE PV II LLC			0.00000	0.00000	
8	KLONDIKE III			0.00000	0.00000	
9	KLONDIKE III S&F			0.00000	0.00000	
10	KLONDIKE IIIA			0.00000	0.00000	
11	KLONDIKE WIND IIIA POWER			0.00000	0.00000	
12	LA JOYA DEL SOL 1			0.00000	0.00000	
13	LA JOYA DEL SOL 1			0.00000	0.00000	
14	LEMOORE PV 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	03/25/2020	End of 2019/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	LIVE OAK LIMITED			0.00000	0.00000	
2	LIVE OAK LIMITED (2013 CHP FRO-2)			0.00000	0.00000	
3	LOST CREEK 1			0.00000	0.00000	
4	LOST CREEK 2			0.00000	0.00000	
5	LOST HILLS SOLAR			0.00000	0.00000	
6	MACQUARIE FUTURES USA - EGS-FCM			0.00000	0.00000	
7	MADERA CHOWCHILLA - SITE 1923			0.00000	0.00000	
8	MADERA CHOWCHILLA SITE 1174			0.00000	0.00000	
9	MADERA CHOWCHILLA SITE 1302			0.00000	0.00000	
10	MADERA CHOWCHILLA SITE 980			0.00000	0.00000	
11	MAMMOTH G1 (ORMAT) - RAM 2			0.00000	0.00000	
12	MAMMOTH G1 RAM 2			0.00000	0.00000	
13	MAMMOTH G3 (M3 ORMAT) - RAM 1			0.00000	0.00000	
14	MAMMOTH G3 RAM 1			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	MANTECA LAND 1			0.00000	0.00000	
2	MARIN CLEAN ENERGY - BU			0.00000	0.00000	
3	MARIN CLEAN ENERGY EEI			0.00000	0.00000	
4	MARIPOSA ENERGY LLC			0.00000	0.00000	
5	MARSH LANDING			0.00000	0.00000	
6	MARSH LANDING CGT			0.00000	0.00000	
7	MATTHEWS DAM HYDRO			0.00000	0.00000	
8	MCE			0.00000	0.00000	
9	MCFADDEN HYDRO FACILITY			0.00000	0.00000	
10	MCFADDEN HYDROELECTRIC FACILITY			0.00000	0.00000	
11	MCKITTRICK LIMITED			0.00000	0.00000	
12	MCKITTRICK LIMITED (2013 CHP FRO-2)			0.00000	0.00000	
13	MERCED 1			0.00000	0.00000	
14	MERCED SOLAR ECOS ENERGY			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	MESQUITE SOLAR			0.00000	0.00000	
2	MIDWAY SUNSET COGENERATION			0.00000	0.00000	
3	MIDWAY SUNSET COGENERATION			0.00000	0.00000	
4	MILL SULPHUR CREEK PROJECT			0.00000	0.00000	
5	MISSION SOLAR ECOS ENERGY			0.00000	0.00000	
6	MOJAVE SOLAR			0.00000	0.00000	
7	MONTEREY BAY COMMUNITY POWER			0.00000	0.00000	
8	MONTEREY BAY COMMUNITY POWER -			0.00000	0.00000	
9	MONTEREY BAY COMMUNITY POWER			0.00000	0.00000	
10	MONTEREY BAY COMMUNITY PWR AUTH			0.00000	0.00000	
11	MORELOS SOLAR LLC - RAM 3			0.00000	0.00000	
12	MORELOS SOLAR LLC RAM 3			0.00000	0.00000	
13	MORGAN STANLEY CAPITAL GROUP EEI			0.00000	0.00000	
14	MT. POSO (RED HAWK)			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	NEXTERA DIABLO WINDS			0.00000	0.00000	
2	NEXTERA MONTEZUMA WIND			0.00000	0.00000	
3	NEXTERA MONTEZUMA WIND II			0.00000	0.00000	
4	NEXTERA MONTEZUMA WIND II			0.00000	0.00000	
5	NICKEL 1 NLH1 SOLAR			0.00000	0.00000	
6	NID CHICAGO PARK			0.00000	0.00000	
7	NID DUTCH FLAT ROLLINS BOWMAN			0.00000	0.00000	
8	NID NORTH COMBIE FIT			0.00000	0.00000	
9	NID SCOTTS FLAT			0.00000	0.00000	
10	NID SOUTH COMBIE FIT			0.00000	0.00000	
11	NID-CHICAGO PARK			0.00000	0.00000	
12	NID-DUTCH FLATS, ROLLINS, BOWMAN			0.00000	0.00000	
13	NORTH SKY RIVER ENERGY CENTER			0.00000	0.00000	
14	NORTH SKY RIVER ENERGY LLC			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	NORTH STAR SOLAR			0.00000	0.00000	
2	NRG ALPINE SOLAR			0.00000	0.00000	
3	NRG SOLAR KANSAS SOUTH			0.00000	0.00000	
4	OAKLEY EXECUTIVE LLC			0.00000	0.00000	
5	OLD RIVER ONE LLC - RAM 3			0.00000	0.00000	
6	OPEN SKY DAIRY DIGESTER #2			0.00000	0.00000	
7	OPEN SKY DIARY DIGESTER #2 - NEW			0.00000	0.00000	
8	ORION SOLAR I LLC			0.00000	0.00000	
9	OROVILLE COGEN			0.00000	0.00000	
10	OROVILLE COGEN TOLLING			0.00000	0.00000	
11	PACIFICORP TSA			0.00000	0.00000	
12	PANOCHE ENERGY CGT			0.00000	0.00000	
13	PCWA LINCOLN HYDRO			0.00000	0.00000	
14	PEACOCK SOLAR PROJ - GREEN LIGHT			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	PEACOCK SOLAR PROJECT			0.00000	0.00000	
2	PENINSULA 2018 REC SALE			0.00000	0.00000	
3	Peninsula CEA			0.00000	0.00000	
4	PENINSULA CLEAN ENERGY - BU			0.00000	0.00000	
5	PENINSULA CLEAN ENERGY 2019			0.00000	0.00000	
6	PENINSULA CLEAN ENERGY 2022			0.00000	0.00000	
7	PENINSULA CLEAN ENERGY AUTHORITY			0.00000	0.00000	
8	PENINSULA CLEAN ENERGY EEI			0.00000	0.00000	
9	PILOT POWER - BU			0.00000	0.00000	
10	PILOT POWER GROUP INC			0.00000	0.00000	
11	PIONEER COMM ENERGY			0.00000	0.00000	
12	PIONEER COMM ENERGY - BU			0.00000	0.00000	
13	PORTAL RIDGE SOLAR C PROJECT			0.00000	0.00000	
14	POTRERO HILLS ENERGY LLC			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	POWEREX CORP			0.00000	0.00000	
2	POWEREX ENERGY CORP			0.00000	0.00000	
3	POWEREX SHAPING FIRMING			0.00000	0.00000	
4	PUTAH CREEK SOLAR FARMS			0.00000	0.00000	
5	RE ASTORIA			0.00000	0.00000	
6	RE TRANQUILLITY 8 AMARILLO			0.00000	0.00000	
7	REDWOOD 4 SOLAR FARM			0.00000	0.00000	
8	RISING TREE WIND FARM II LLC			0.00000	0.00000	
9	RISING TREE WIND FARM II LLC - RAM 4			0.00000	0.00000	
10	ROCK CREEK HYDRO			0.00000	0.00000	
11	SACRAMENTO MUNICIPAL UTILITY DIS			0.00000	0.00000	
12	SALMON CREEK HYDROELECTRIC			0.00000	0.00000	
13	SALMON CREEK HYDROELECTRIC			0.00000	0.00000	
14	SAN JOSE CLEAN ENERGY			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SAN JOSE CLEAN ENERGY - BU			0.00000	0.00000	
2	SAN JOSE WATER COX AVE HYDRO			0.00000	0.00000	
3	SAN LUIS BYPASS			0.00000	0.00000	
4	SAN LUIS BYPASS (CCID)			0.00000	0.00000	
5	SAN LUIS OBISPO AD			0.00000	0.00000	
6	SAN LUIS OBISPO AD - NEW			0.00000	0.00000	
7	SANTA MARIA II LFG POWER			0.00000	0.00000	
8	SANTA MARIA II LFG POWER PLANT			0.00000	0.00000	
9	SEMPRA GENERATION EEI			0.00000	0.00000	
10	SEMPRA MESQUITE SOLAR			0.00000	0.00000	
11	SFWP SLY CREEK KELLY RIDGE			0.00000	0.00000	
12	SFWP WOODLEAF FORBESTOWN			0.00000	0.00000	
13	SHAFTER SOLAR LLC			0.00000	0.00000	
14	SHAFTER SOLAR LLC RAM 3			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Shell Energy			0.00000	0.00000	
2	SHELL ENERGY 2019 REC SALE 1			0.00000	0.00000	
3	SHELL ENERGY 2019 REC SALE 2			0.00000	0.00000	
4	SHELL ENERGY NORTH AMERICA			0.00000	0.00000	
5	SHELL ENERGY US - BU			0.00000	0.00000	
6	SHILOH I WIND			0.00000	0.00000	
7	SHILOH I WIND PROJECT LLC			0.00000	0.00000	
8	SHILOH II WIND (AKA ENXCO)			0.00000	0.00000	
9	SHILOH II WIND PROJECT AR			0.00000	0.00000	
10	SHILOH III (ENXCO)			0.00000	0.00000	
11	SHILOH III WIND PROJECT			0.00000	0.00000	
12	SHILOH IV			0.00000	0.00000	
13	SIERRA GREEN ENERGY LLC			0.00000	0.00000	
14	SIERRA PACIFIC INDUSTRIES			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SIERRA PACIFIC POWER TSA			0.00000	0.00000	
2	SILICON VALLEY CLEAN ENERGY - BU			0.00000	0.00000	
3	SILICON VALLEY CLEAN ENERGY AUTH			0.00000	0.00000	
4	SILICON VALLEY CLEAN ENERGY EEI			0.00000	0.00000	
5	SILVER SPRINGS			0.00000	0.00000	
6	Silver Springs (Mega)			0.00000	0.00000	
7	SMUD - BU			0.00000	0.00000	
8	SMUD EEI MASTER			0.00000	0.00000	
9	SMUD WSPP			0.00000	0.00000	
10	SOLAR PARTNERS II (IVANPAH UNIT 1)			0.00000	0.00000	
11	SOLAR PARTNERS VIII (IVANPAH UNIT 3)			0.00000	0.00000	
12	SONOMA CLEAN POWER AUTHORITY			0.00000	0.00000	
13	SONOMA POWER - BU			0.00000	0.00000	
14	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
2	SOUTH SUTTER WATER DISTRICT (expired			0.00000	0.00000	
3	SPP/NEVP SOUTH DELIVERY TSA			0.00000	0.00000	
4	SR SOLIS ORO - PROJECT A			0.00000	0.00000	
5	SR SOLIS ORO - PROJECT B			0.00000	0.00000	
6	SR Solis Oro Loma Teresina Solar Proje			0.00000	0.00000	
7	SR Solis Oro Loma Teresina Solar Proje			0.00000	0.00000	
8	STARWOOD POWER MIDWAY, LLC			0.00000	0.00000	
9	SUMMER WHEAT SAN JOAQUIN 1A			0.00000	0.00000	
10	Summer Wheat Solar Farm (San Joaquin 1			0.00000	0.00000	
11	SUN HARVEST SOLAR NDP1			0.00000	0.00000	
12	SUN HARVEST SOLAR, LLC (NDP1)			0.00000	0.00000	
13	SUNRAY 2			0.00000	0.00000	
14	SUNSHINE GAS LANDFILL			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SUTTERS MILL HYDROELECTRIC PLANT			0.00000	0.00000	
2	SUTTERS MILL HYDROELECTRIC			0.00000	0.00000	
3	TESORO - MARTINEZ COGEN LP			0.00000	0.00000	
4	TESORO REFINING & MARKETING LLC			0.00000	0.00000	
5	THE ENERGY AUTHORITY - BU			0.00000	0.00000	
6	THE ENERGY AUTHORITY 2019 REC			0.00000	0.00000	
7	THE ENERGY AUTHORITY EEI			0.00000	0.00000	
8	THREE FORKS			0.00000	0.00000	
9	TOPAZ SOLAR FARM			0.00000	0.00000	
10	TOPAZ SOLAR FARMS			0.00000	0.00000	
11	TORO SLO LANDFILL			0.00000	0.00000	
12	TRANSALTA ENREGY MARKETING US			0.00000	0.00000	
13	TULLETT PREBON AMERICAS CORP			0.00000	0.00000	
14	TUNNEL HILL 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	03/25/2020	End of 2019/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	TWIN VALLEY HYDRO			0.00000	0.00000	
2	VANTAGE WIND (POWEREX S&F) (Do not			0.00000	0.00000	
3	VANTAGE WIND ENERGY LLC			0.00000	0.00000	
4	VASCO WINDS (NEXTERA)			0.00000	0.00000	
5	VASCO WINDS NEXTERA			0.00000	0.00000	
6	VERWEY HANFORD DAIRY 2 - NEW			0.00000	0.00000	
7	VERWEY HANFORD DAIRY 3 - NEW			0.00000	0.00000	
8	VERWEY MADERA DAIRY DIGESTER 2			0.00000	0.00000	
9	VERWEY MADERA DAIRY DIGESTER 2			0.00000	0.00000	
10	VERWEY-HANFORD DAIRY 2			0.00000	0.00000	
11	VERWEY-HANFORD DAIRY 3			0.00000	0.00000	
12	VINTNER SOLAR LLC			0.00000	0.00000	
13	VINTNER SOLAR PROJECT			0.00000	0.00000	
14	WATER WHEEL RANCH			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	WECC WREGIS FEES			0.00000	0.00000	
2	WEST ANTELOPE - RAM 1			0.00000	0.00000	
3	WEST ANTELOPE RAM 1			0.00000	0.00000	
4	WESTERN ANTELOPE BLUE SKY			0.00000	0.00000	
5	WESTERN ANTELOPE BLUE SKY RANCH			0.00000	0.00000	
6	WESTERN ELECTRICITY COORDINATING			0.00000	0.00000	
7	WESTLANDS SOLAR FARMS LLC			0.00000	0.00000	
8	Westside Solar			0.00000	0.00000	
9	WHEELABRATOR SHASTA			0.00000	0.00000	
10	WHITE RIVER SOLAR 2			0.00000	0.00000	
11	WHITE RIVER SOLAR CED			0.00000	0.00000	
12	WIND RESOURCE 1 (CALWIND) - RAM 1			0.00000	0.00000	
13	WIND RESOURCE 2 CALWIND RAM 2			0.00000	0.00000	
14	WINTER WHEAT SAN JOAQUIN 1B			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	WOLFSEN BYPASS (CCID)			0.00000	0.00000	
2	WOLFSEN BYPASS FIT			0.00000	0.00000	
3	WOODLAND BIOMASS			0.00000	0.00000	
4	WOODMERE SOLAR FARM			0.00000	0.00000	
5	WOODMERE SOLAR RAM 4			0.00000	0.00000	
6	YCWA MINI HYDRO			0.00000	0.00000	
7	YOLO COUNTY GRASSLAND 3			0.00000	0.00000	
8	YOLO COUNTY GRASSLAND 4			0.00000	0.00000	
9	ZERO WASTE ENERGY DEVELOPMENT			0.00000	0.00000	
10						
11						
12	Pipeline charges			0.00000	0.00000	
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	03/25/2020	End of 2019/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	RUBY PIPELINE			0.00000	0.00000	
2	WILLIAMS FIELD SERVICES -			0.00000	0.00000	
3	SOUTHERN CA GAS - BU			0.00000	0.00000	
4						
5	Other charges			0.00000	0.00000	
6	Irrigation districts			0.00000	0.00000	
7	Liberty Utilities			0.00000	0.00000	
8	ISO charges for storage cost			0.00000	0.00000	
9	ISO charges (net of storage cost but			0.00000	0.00000	
10	Gas purchases, storage cost & forex			0.00000	0.00000	
11	CARB fees			0.00000	0.00000	
12	Consultancy fees			0.00000	0.00000	
13	Gas Hedges & brokers fees			0.00000	0.00000	
14	RECS from customers			0.00000	0.00000	
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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						
3	Rounding in column I					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
157			347	6,166		6,513	3
619			3,420	26,812		30,232	4
			-2,974,197			-2,974,197	5
54			227	2,086		2,313	6
186			543	8,305		8,848	7
348			3,098	15,677		18,775	8
59,252			702,990	2,496,763		3,199,753	9
130			246	4,855		5,101	10
7			18	287		305	11
							12
4,896			58,522	213,968		272,490	13
9,917			7,518	-156,109		-148,591	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
17,973			237,192	438,204		675,396	1
8,900			119,414	392,376		511,790	2
15,314			197,640	645,204		842,844	3
3,804			76,810	151,289		228,099	4
							5
83,310			2,107,464	3,666,329		5,773,793	6
975			6,687	37,047		43,734	7
-12,687			-355,605	-537,703		-893,308	8
							9
1,413			543	27,635		28,178	10
12,134			126,398	273,469		399,867	11
1,942			1,369	44,006		45,375	12
							13
8			38	278		316	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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.
275			2,209	11,296		13,505	1
							2
104			639	5,035		5,674	3
565			5,313	20,794		26,107	4
				8		8	5
12,425			63,957	520,187		584,144	6
3,775			84,659	151,668		236,327	7
971			19,744	37,822		57,566	8
50,728				2,106,893		2,106,893	9
2			7	96		103	10
1			1	65		66	11
							12
							13
1,519,605			52,948,686	63,740,043		116,688,729	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
32,897			134,071	1,334,767		1,468,838	1
-1,002			-53,249	137,492		84,243	2
							3
672			3,515	27,432		30,947	4
6				212		212	5
259			752	12,050		12,802	6
8,736			17,465	513,018		530,483	7
13			31	562		593	8
6,799			16,869	288,326		305,195	9
				1		1	10
71			220	3,044		3,264	11
24			81	1,007		1,088	12
49			155	2,121		2,276	13
15			35	694		729	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
				3		3	1
							2
25,246			909,692	2,078,543		2,988,235	3
213,195			9,398,137	8,167,882		17,566,019	4
2,367			10,440,324	216,072		10,656,396	5
							6
108,581			3,531,657	6,513,764		10,045,421	7
529			1,903	20,287		22,190	8
124			200	5,542		5,742	9
55			64	1,974		2,038	10
3,564			7,311,234	310,264		7,621,498	11
4,049			9,697,157	211,183		9,908,340	12
20,347				1,174,041		1,174,041	13
6,975			72,781	276,287		349,068	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
29,543			197,836	1,177,187		1,375,023	1
4,472			22,837	155,012		177,849	2
576				18,963		18,963	3
476			1,280	18,526		19,806	4
11,908			135,716	466,354		602,070	5
145,173			1,616,103	6,029,960		7,646,063	6
65,461			528,159	2,664,624		3,192,783	7
6,343			15,001	276,735		291,736	8
7,041			35,556	287,815		323,371	9
32,482			218,522	1,281,019		1,499,541	10
7,148			32,595	272,356		304,951	11
14,724			96,492	598,571		695,063	12
							13
							14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,001,962				16,795,368		16,795,368	1
514				76,858		76,858	2
2,204				318,814		318,814	3
1,151				169,092		169,092	4
393				60,114		60,114	5
2,361				336,950	-16,182	320,768	6
1,083				162,131		162,131	7
1,707				255,609		255,609	8
4,754				758,295		758,295	9
1,479				215,816		215,816	10
712				107,129		107,129	11
1,086				72,236		72,236	12
250				41,517		41,517	13
375				51,749		51,749	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
2,340				448,201		448,201	1
566				90,393		90,393	2
974				139,691		139,691	3
540				80,328		80,328	4
3,566				337,304		337,304	5
1,154				160,176		160,176	6
			-78,000			-78,000	7
-50,000				-800,000		-800,000	8
			-786,650			-786,650	9
7,972				1,451,612		1,451,612	10
6,505				1,283,933		1,283,933	11
7,963				1,451,727		1,451,727	12
11,750				1,853,509		1,853,509	13
1,019				194,017	-3,686	190,331	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
721,672				125,450,406		125,450,406	1
2,033				169,726		169,726	2
39,362				3,446,418		3,446,418	3
			755,290			755,290	4
			7,412,950			7,412,950	5
48,130				4,226,914		4,226,914	6
108,989				19,802,670		19,802,670	7
45,417				7,589,933		7,589,933	8
5,679				492,755		492,755	9
718				64,026		64,026	10
1,868				233,547		233,547	11
74				7,127		7,127	12
7,818				754,806		754,806	13
185,094				18,895,779		18,895,779	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
19,985				1,337,502		1,337,502	1
37,793				6,431,095		6,431,095	2
549,870				85,940,761		85,940,761	3
				3,336,420		3,336,420	4
-100,000				-1,800,000		-1,800,000	5
15,087				909,597		909,597	6
14,809				885,202		885,202	7
13,775			3,556,035	338,327		3,894,362	8
			347,420	40,334		387,754	9
1,105				100,200		100,200	10
3,314				437,106		437,106	11
2,149				185,152		185,152	12
9,758				695,641		695,641	13
54,130				3,234,007		3,234,007	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
52,804				3,151,258		3,151,258	1
52,349				3,130,504		3,130,504	2
3,879				563,662		563,662	3
29,786			3,459,469	636,834		4,096,303	4
			347,420	39,634		387,054	5
8,041				726,485		726,485	6
				13,855,545		13,855,545	7
				1,918,562		1,918,562	8
				14,851,400		14,851,400	9
				2,056,069		2,056,069	10
31,635				3,330,268		3,330,268	11
213				18,743		18,743	12
				17,305		17,305	13
40,450				1,512,990		1,512,990	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
				57,420		57,420	1
					7,066	7,066	2
3,524				277,888		277,888	3
1,333				126,558		126,558	4
50,993				23,896,313		23,896,313	5
14,362				1,630,075		1,630,075	6
340				1,220		1,220	7
323				32,113		32,113	8
33				2,922		2,922	9
321,154				22,504,013		22,504,013	10
13,508				731,814		731,814	11
6,710			5,957,196	213,200		6,170,396	12
			-2,428,700			-2,428,700	13
-250,000				-4,500,000		-4,500,000	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
			-138,750			-138,750	1
106,492				9,707,771		9,707,771	2
191,441			61,255,706	5,066,197		66,321,903	3
15,303			6,083,021	54,655		6,137,676	4
81,543			32,087,363	3,986,180		36,073,543	5
747,880			130,016,455	18,901,772		148,918,227	6
116,333			15,913,374	1,653,290		17,566,664	7
8,531				2,041,599		2,041,599	8
457				97,755		97,755	9
16,414			5,124,730	430,403	174,955	5,730,088	10
16,792			5,133,866	432,798	176,396	5,743,060	11
13,591			5,081,027	320,644	173,013	5,574,684	12
309				28,517		28,517	13
2,101				283,183		283,183	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6				645		645	1
			-320,605			-320,605	2
50,090				2,524,035		2,524,035	3
1,784				127,266		127,266	4
1,783				246,477		246,477	5
160				14,336		14,336	6
893				77,322		77,322	7
8,948			3,526,149	206,011		3,732,160	8
			347,420	17,909		365,329	9
44,596				5,221,729		5,221,729	10
1,675				134,192		134,192	11
-10,000				-190,000		-190,000	12
-650,000				-10,562,500		-10,562,500	13
			73,260			73,260	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
-1,500,000			-2,246,287	-23,670,000		-25,916,287	1
-1,200,000				-19,000,000		-19,000,000	2
			-6,012,350		-95	-6,012,445	3
4,746				409,552		409,552	4
69				6,170		6,170	5
245				22,250		22,250	6
58				5,190		5,190	7
566				49,368		49,368	8
2,131				280,907		280,907	9
39,123				3,759,153		3,759,153	10
			-677,000			-677,000	11
181,411				10,859,980		10,859,980	12
24,603				3,813,908		3,813,908	13
333,140				44,705,090		44,705,090	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
14,546				1,433,901		1,433,901	1
98,370				16,036,193		16,036,193	2
254,724				29,695,330	-2,500	29,692,830	3
44,918				7,630,044		7,630,044	4
			-637,265			-637,265	5
100,180				10,768,699		10,768,699	6
4,514				356,042		356,042	7
80				7,126		7,126	8
2,000				155,874	-5,686	150,188	9
699,519				112,368,994		112,368,994	10
3,568				316,958		316,958	11
-80,000				-1,380,800		-1,380,800	12
			-470,750			-470,750	13
-25,000				-418,750		-418,750	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-150,000				-2,482,500		-2,482,500	1
-80,000				-1,164,000		-1,164,000	2
			-2,135,190			-2,135,190	3
			-4,609,500			-4,609,500	4
5,437				634,578		634,578	5
375,224				45,507,017		45,507,017	6
10,959				1,226,012		1,226,012	7
13,592				1,268,319		1,268,319	8
-100,000				-1,850,000		-1,850,000	9
-1,278,919				-17,904,866		-17,904,866	10
			-13,015,950			-13,015,950	11
			-265,869			-265,869	12
-525,000				-8,718,750		-8,718,750	13
2,565				378,816		378,816	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
503				47,570		47,570	1
			552,783			552,783	2
-176,000				-2,831,840		-2,831,840	3
629,594			56,337,095	4,824,961		61,162,056	4
82,740				9,315,741		9,315,741	5
3,367				500,820		500,820	6
					5,312	5,312	7
-2				42,658		42,658	8
10,069				2,549,729		2,549,729	9
30,957				7,724,344		7,724,344	10
31,582				7,851,743		7,851,743	11
38,069				-93,165		-93,165	12
			-465,314			-465,314	13
-379,869				-7,027,577		-7,027,577	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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.
-800,000				-12,800,000		-12,800,000	1
			-7,701,056			-7,701,056	2
3,658				548,355		548,355	3
3,575				532,335		532,335	4
3,542				629,314		629,314	5
2,972				401,904		401,904	6
3,288				430,892		430,892	7
606,102				130,366,424		130,366,424	8
13,534				2,318,620		2,318,620	9
1,896,245			12,125,000	146,753,269		158,878,269	10
78,917				8,380,925		8,380,925	11
51,080				5,566,917		5,566,917	12
267				24,320		24,320	13
2,496				202,120		202,120	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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.
90				8,006		8,006	1
529				50,672		50,672	2
2,596				145,668		145,668	3
1,931				254,238		254,238	4
10,677			7,598,278	432,454		8,030,732	5
			771,701	4,233		775,934	6
30,781			7,545,450	795,159		8,340,609	7
106			762,900	8,173		771,073	8
706,033			63,024,275	11,009,772		74,034,047	9
112,016			6,233,731	-374,125		5,859,606	10
				16,089,627	709,133	16,798,760	11
				2,116,664		2,116,664	12
231,148				24,168,111		24,168,111	13
237,655				24,990,137		24,990,137	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
			-365,000			-365,000	1
			-730,000			-730,000	2
485,370				65,153,618		65,153,618	3
21,505				2,680,711		2,680,711	4
94,241				13,366,028		13,366,028	5
3,832				514,747		514,747	6
9,213				538,986		538,986	7
				314,214		314,214	8
					117,350	117,350	9
126				12,604		12,604	10
234,815				38,727,537		38,727,537	11
246,355				41,365,762		41,365,762	12
1,512				137,818		137,818	13
49,895				5,259,501		5,259,501	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
75				5,109		5,109	1
50,600				4,452,787		4,452,787	2
611,315			17,983,710	23,515,397		41,499,107	3
2,845			1,486,791	123,288		1,610,079	4
2,742				394,592	-5,000	389,592	5
2,881				411,261		411,261	6
1,356				248,270		248,270	7
192,850				11,281,724		11,281,724	8
-13,609				4,947,008		4,947,008	9
6,922				1,804,078		1,804,078	10
-534				1,734,084		1,734,084	11
2,063				277,254		277,254	12
14				1,409		1,409	13
1,292				171,561		171,561	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
11,793			3,524,366	291,521		3,815,887	1
			347,420	41,087		388,507	2
6,009				610,074		610,074	3
2,655				271,410		271,410	4
52,989				5,557,132		5,557,132	5
			1,613,940		24,715,888	26,329,828	6
2,776				246,395		246,395	7
2,221				197,577		197,577	8
1,167				104,734		104,734	9
3,860				331,048		331,048	10
1,060				-83,432		-83,432	11
51,868				4,506,035		4,506,035	12
9,693				-813,729		-813,729	13
72,623				6,676,942		6,676,942	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,988				178,336		178,336	1
			-177,500			-177,500	2
			-5,360,255			-5,360,255	3
88,431			30,195,229	1,432,931		31,628,160	4
76,376			118,919,197	2,166,029		121,085,226	5
				198,178		198,178	6
5,496				473,348		473,348	7
-300,000				-5,628,000		-5,628,000	8
245				21,951		21,951	9
61				5,424		5,424	10
6,913			3,556,754	332,516		3,889,270	11
			347,420	30,633		378,053	12
6,271				378,687		378,687	13
3,776				502,725		502,725	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
23,311				2,987,783		2,987,783	1
652,866			13,595,545	422,611		14,018,156	2
67,664			1,418,445	-600,597		817,848	3
1,896				164,514		164,514	4
3,764				498,039		498,039	5
507,758				100,650,375		100,650,375	6
-800,000			-3,628,126	-1,264,000		-4,892,126	7
			-84,510			-84,510	8
-135,000				-2,227,500		-2,227,500	9
-751,000				-11,979,250		-11,979,250	10
1,160				78,000		78,000	11
34,975				3,244,239		3,244,239	12
20,000				121,565		121,565	13
300,094				40,582,810		40,582,810	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
54,950				3,009,750		3,009,750	1
89,745				9,064,271	-2,500	9,061,771	2
194,098				19,797,951	-2,500	19,795,451	3
7,618				777,085		777,085	4
2,309				314,932	-889	314,043	5
141,915				9,367,154		9,367,154	6
188,115				11,365,151		11,365,151	7
1,785				190,949		190,949	8
4,638				407,552		407,552	9
7,755				756,717		756,717	10
7,805				916,989		916,989	11
7,273				1,108,315		1,108,315	12
20,020				1,739,768		1,739,768	13
413,671				36,251,443		36,251,443	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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.
150,195				20,069,205		20,069,205	1
155,390				22,694,040		22,694,040	2
49,233				4,994,167		4,994,167	3
2,172				316,853		316,853	4
49,171				4,201,644		4,201,644	5
2,697				516,668		516,668	6
389				78,604		78,604	7
26,177				3,402,750		3,402,750	8
			103,329			103,329	9
144			1,034,803	6,723		1,041,526	10
					9,299	9,299	11
				1,278,638		1,278,638	12
798				81,475		81,475	13
67				6,454		6,454	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
1,440				201,375		201,375	1
-50,000				-850,000		-850,000	2
-50,000				-875,000		-875,000	3
			-300,250			-300,250	4
-431,973				-6,483,915		-6,483,915	5
-17,038				-272,608		-272,608	6
-42,108				-636,081		-636,081	7
			-7,330,080			-7,330,080	8
			-82,950			-82,950	9
			-912,450			-912,450	10
			-3,531,635			-3,531,635	11
			-4,000			-4,000	12
30,611				2,013,162		2,013,162	13
57,736				7,242,850		7,242,850	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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.
-175,000				-2,892,750		-2,892,750	1
-350,000				-6,793,500		-6,793,500	2
				9,176,080	18,045	9,194,125	3
5,090				555,616		555,616	4
281,202				19,168,179	-15,500	19,152,679	5
55,118				3,571,780		3,571,780	6
51,248				3,272,371		3,272,371	7
53,153				3,343,236		3,343,236	8
2,272				116,990		116,990	9
1,704				146,928		146,928	10
-159,500				-2,521,695		-2,521,695	11
2,044				178,913		178,913	12
218				19,468		19,468	13
			-15,455,374			-15,455,374	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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.
			-1,781,122			-1,781,122	1
109				15,643		15,643	2
613				67,710		67,710	3
44				4,559		4,559	4
597				80,987		80,987	5
17				2,354		2,354	6
7,872				755,476		755,476	7
412				40,036		40,036	8
132,745				4,778,821		4,778,821	9
383,659				62,523,096		62,523,096	10
97,426			1,434,088	3,280,322		4,714,410	11
334,659			2,792,593	12,270,079		15,062,672	12
1,909				135,245		135,245	13
49,658				4,866,704	-4,500	4,862,204	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-300,000				-5,250,000		-5,250,000	1
-100,000				-1,500,000		-1,500,000	2
-100,000				-1,500,000		-1,500,000	3
			-4,447,270			-4,447,270	4
			-243,750			-243,750	5
181,856				10,378,338		10,378,338	6
7,652				298,028		298,028	7
15,225				1,323,096		1,323,096	8
371,533				32,286,199	-14,500	32,271,699	9
10,513				1,206,324		1,206,324	10
257,817				29,584,537	-9,000	29,575,537	11
271,768				24,566,543	-9,000	24,557,543	12
120				14,319		14,319	13
374,983				33,550,411		33,550,411	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					16,576	16,576	1
			-368,750			-368,750	2
-400,000				-6,100,000		-6,100,000	3
			-6,918,826			-6,918,826	4
2,285				197,950		197,950	5
142				12,658		12,658	6
			-175,900			-175,900	7
			-728,000			-728,000	8
			-3,256,150			-3,256,150	9
9,357				1,221,796		1,221,796	10
10,395				1,390,206		1,390,206	11
			-2,396,875			-2,396,875	12
			-268,100			-268,100	13
8,231				469,979		469,979	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
31,260				1,592,923		1,592,923	1
141				-14,200		-14,200	2
					7,634	7,634	3
22,629				1,161,956		1,161,956	4
22,530				1,155,115		1,155,115	5
796				40,083		40,083	6
689				34,670		34,670	7
51,358			13,472,841	860,279		14,333,120	8
47,208				2,420,081	-3,000	2,417,081	9
1,893				95,462		95,462	10
3,154				285,959		285,959	11
73				6,524		6,524	12
57,094				3,528,613		3,528,613	13
136,280				16,561,872		16,561,872	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
660				58,106		58,106	1
61				5,473		5,473	2
3,479			11,385	140,828		152,213	3
81,546			600,145	2,797,715		3,397,860	4
			-24,960			-24,960	5
-30,000				-472,500		-472,500	6
			-1,974,632			-1,974,632	7
6,877				683,978		683,978	8
74,940				11,442,957		11,442,957	9
1,184,418				197,022,631	-14,988	197,007,643	10
11,206				1,231,517		1,231,517	11
131,234			413,000	5,373,479		5,786,479	12
					15,026	15,026	13
2,219				217,886		217,886	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
2,132				256,639		256,639	1
				672,456		672,456	2
240,683				25,192,777		25,192,777	3
8,279				894,168		894,168	4
232,729				25,134,720		25,134,720	5
402				93,127		93,127	6
410				94,766		94,766	7
3,756				808,981		808,981	8
360				81,970		81,970	9
2,829				610,399		610,399	10
2,727				590,949		590,949	11
3,896				583,751		583,751	12
222				21,018		21,018	13
2,505				220,770		220,770	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
				143,062		143,062	1
2,441				159,017		159,017	2
55,003				4,784,721		4,784,721	3
49,511				3,601,922		3,601,922	4
1,820				97,448		97,448	5
				4,246		4,246	6
43,057				5,673,927		5,673,927	7
50,961				3,273,603		3,273,603	8
89,899				35,740,114		35,740,114	9
47,497				4,793,714		4,793,714	10
45,372				7,653,531		7,653,531	11
14,171				1,073,579		1,073,579	12
48,494				3,730,164	-8,500	3,721,664	13
1,943				60,784		60,784	14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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)	
56				6,004		6,004	1
1,674				172,590		172,590	2
166,742				16,903,438		16,903,438	3
1,314				69,123		69,123	4
35,183				2,608,040		2,608,040	5
1,190				106,241		106,241	6
2,379				283,650	-10,000	273,650	7
2,445				291,118		291,118	8
4,126				528,430	-13,665	514,765	9
							10
							11
							12
							13
							14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
					9,938,572	9,938,572	1
					1,139	1,139	2
					15,654	15,654	3
							4
							5
44,896					3,962,441	3,962,441	6
4,624					846,251	846,251	7
					142,776	142,776	8
27,332,628					943,242,549	943,242,549	9
					91,264,629	91,264,629	10
					593,662	593,662	11
					178,135	178,135	12
					28,967,523	28,967,523	13
							14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

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
					1,587	1,587	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
42,164,686			649,573,752	2,303,644,431	1,105,158,920	4,058,377,103	

Schedule Page: 326.38 Line No.: 3 Column: a

The original entries in column l were in two decimal places, which the FERC software rounds automatically to whole numbers. The entry here is an adjustment to present the correct total.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
143	Midway	Various	233	524,276	514,362	3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			233	**524,276**	**514,362**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
	2,638,524	-80,000	2,558,524	3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	**2,638,524**	**-80,000**	**2,558,524**	

Schedule Page: 328 Line No.: 3 Column: a

Other Charges represent booking estimate adjustments. In September 2003 the Utility changed billing methodology using energy as billing determinants rather than contract demand. The change was pursuant to the TO6 Settlement Agreement under FERC Docket No. ER03-666-000.

Transmission is provided under the Midway Transmission Service.

Recorded here are the Midway Transmission Service data for TANC members which include Modesto Irrigation District, Sacramento Municipal Utility District, City of Redding, and the Turlock Irrigation District.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	CALIFORNIA-OREGON							
2	TRANSMISSION PROJECT	OS					448,720	448,720
3	PACIFICORP	OS			135,015		81,697	216,712
4	SACRAMENTO MUNICIPAL							
5	UTILITY DISTRICT	OS						
6	WESTERN AREA POWER							
7	ADMINISTRATION	OS			2,208			2,208
8	CALIFORNIA-OREGON							
9	INTERTIE	OS					347,082	347,082
10	OTHER	OS						
11								
12								
13								
14								
15								
16								
	TOTAL				137,223		877,499	1,014,722

Schedule Page: 332 Line No.: 2 Column: g

Represents payments for operations and maintenance costs.

Schedule Page: 332 Line No.: 3 Column: e

Represents payments for lease of transmission capacity.

Schedule Page: 332 Line No.: 3 Column: g

Represents payments for operations and maintenance costs.

Schedule Page: 332 Line No.: 7 Column: e

Represents payments for lease of transmission capacity.

Schedule Page: 332 Line No.: 9 Column: g

Represents payments for administrative costs of scheduling services provided by the California Independent Systems Operator (CAISO).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	40
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	185,087
7	Intervenor Compensation	4,411,633
8	MCI-PG&E Exchange Rights	650,161
9	Bank Service Fees	17,596,257
10	Consulting Serv,Outside Attorney Fee, and Contracts	220,427
11	Misc cash receipt (recovery of unclaimed funds)	-39,671
12	Write off from miscellenous reconciliations	-6,818
13	Other miscelleneous adjustments	2,652
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	23,019,768

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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			3,119,863		3,119,863
2	Steam Production Plant	20,091,983				20,091,983
3	Nuclear Production Plant	265,700,382			38,731,572	304,431,954
4	Hydraulic Production Plant-Conventional	78,935,546			4,752,000	83,687,546
5	Hydraulic Production Plant-Pumped Storage	12,510,675			2,280,000	14,790,675
6	Other Production Plant	46,573,530				46,573,530
7	Transmission Plant	327,486,350				327,486,350
8	Distribution Plant	1,293,520,408				1,293,520,408
9	Regional Transmission and Market Operation					
10	General Plant	38,909,665				38,909,665
11	Common Plant-Electric	154,022,583		169,616,521		323,639,104
12	TOTAL	2,237,751,122		172,736,384	45,763,572	2,456,251,078

B. Basis for Amortization Charges

The basis used to compute the charges is the ending plant balance. The basis is different from the preceding year due to net plant additions throughout the year. The rates have been updated in accordance with 2017 GRC authorized rates.

The rates used to compute amortization charges for 'Intangible Plant – Electric' (Account 404) are as follows:
EIP30201 Intangible Plant: Franchise 2.19%; EIP30301 Intangible Plant: USBR 0%; EIP30303 Intangible Plant: Software 2.11%

The rates used to compute amortization charges for 'Common Plant – Electric' (Account 404) are as follows:
CMP30302 Intangible Plant: Software 21.45%; CMP30304 Intangible Plant: Software 6.61%

For FERC reporting purposes, common amortization expense is allocated to electric and gas amortization as common amortization expense is not reported on the FERC forms. The rate used to allocate the common amortization expense to electric is 64.71%.

Amortization of the Other Electric Plant (Account 405) - These amortization amounts represent the 2017 GRC authorized amounts to record for the recovery of the URG regulatory asset. In connection with the Chapter 11 Settlement Agreement, the CPUC authorized the Utility to recover $1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities or recovery period, consistent with the period over which the related revenues are recognized.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Prod - Fossil						
13	310.02	4,801			2.18	SQ	
14	311	113,966	75.00		3.46	R1	18.70
15	312	279,931	50.00		3.69	R1	17.90
16	313						
17	314	257,634	40.00		3.56	R2.5	18.30
18	315	52,626	45.00		3.55	R2.5	18.70
19	316	28,349	40.00		3.77	S0.5	17.20
20	SUBTOTAL	737,307					
21							
22	Nuclear Prod - Diablo						
23	321	1,092,064	100.00	-1.00		Life Span	5.30
24	322	3,594,709	65.00	-1.00		Life Span	4.90
25	323	1,203,202	50.00	-1.00		Life Span	4.70
26	324	866,818	75.00			Life Span	5.10
27	325	1,171,137	50.00	-1.00		Life Span	5.20
28	SUBTOTAL	7,927,930					
29							
30	Hydraulic Production						
31	330	17,311			1.84	SQ	
32	331	536,800	80.00	-2.00	1.73	R2	12.80
33	332	2,142,386	120.00	-3.00	1.60	R2.5	17.20
34	333	1,053,071	81.00	-3.00	3.10	R1	13.70
35	334	312,359	65.00	-6.00	3.02	R1.5	14.70
36	335	120,293	60.00	-9.00	3.22	S0.5	13.90
37	336	97,961	87.00	-2.00	2.49	S1.5	16.10
38	SUBTOTAL	4,280,181					
39							
40	Other Production						
41	340.02	3,121			0.64	SQ	
42	341	211,013	59.00		3.69	R1,SQ	18.60
43	342	11,473	50.00		3.69	R1	18.00
44	343	227,980	40.00		3.57	R2.5	18.50
45	344	353,878	27.00		4.35	R2.5,SQ	17.40
46	345	214,406	31.00		5.71	R2.5,S2.5,SQ	14.60
47	346	98,909	35.00		3.84	S0.5,SQ	17.30
48	SUBTOTAL	1,120,780					
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Transmission						
13	350.02	216,184	40.00		3.94	R4	22.70
14	352	533,790	65.00	-20.00	1.80	R3	54.70
15	353	6,839,541	55.00	-5.00	2.24	R1.5	37.10
16	354	993,405	75.00	-66.00	2.26	R4	54.70
17	355	1,660,778	52.00	-65.00	2.99	R1.5	43.30
18	356	1,984,507	65.00	-70.00	2.57	R2	50.80
19	357	512,723	65.00		1.52	R4	52.80
20	358	276,587	55.00	-10.00	1.99	R3	41.10
21	359	119,505	60.00	-10.00	1.91	R1.5	50.90
22	SUBTOTAL	13,137,020					
23							
24	Transmission - Diablo						
25	352.01	4,940	65.00		1.43		5.40
26	353.01	89,971	45.00	-20.00	2.69	R2	10.40
27	SUBTOTAL	94,911					
28							
29	Distribution						
30	360.02	122,720	41.00		2.12	SQ	18.60
31	361	323,811	65.00	-20.00	1.78	R3	45.60
32	362	3,716,236	46.00	-40.00	3.06	R1.5	32.40
33	363	31,647	15.00		6.41	R2,S3	8.40
34	364	5,601,157	44.00	-150.00	6.03	R1.5	31.80
35	365	5,102,562	46.00	-125.00	5.05	R2	31.80
36	366	3,133,715	62.00	-50.00	2.60	R4	43.50
37	367	5,043,962	47.00	-65.00	3.35	R3	30.60
38	368	4,141,286	32.00	-27.00	4.39	R2.5,R3	21.10
39	369	3,606,411	47.00	-67.00	3.51	R2.5,R4	27.50
40	370	1,249,822	20.00	-15.00	6.21	R1.5	12.60
41	371	29,314	37.00	-3.00	0.23	S1	3.30
42	372	895	25.00			L1	
43	373	264,243	28.00	-23.00	3.25	R0.5,S1.5,L0,S1	9.60
44	SUBTOTAL	32,367,781					
45							
46	General Plant						
47	389.02	415	59.00		2.74	SQ	29.90
48	390	12,683	50.00	-10.00	1.62	R2	30.90
49	391	10,770	20.00		6.20	SQ	10.30
50	394	156,770	25.00		3.85	SQ	16.90

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	395	12,102	20.00		5.37	SQ	11.90
13	396						
14	397	441,617	15.00		6.25	SQ	11.90
15	398	31,228	20.00		13.04	SQ	17.10
16	SUBTOTAL	665,585					
17							
18	General Plant - Diablo						
19	391	4,509	20.00		5.23		15.50
20	398	15,882	20.00		5.39		14.90
21	SUBTOTAL	20,391					
22							
23	TOTAL	60,351,886					
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							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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 5000275	3,760,750		3,760,750	
4	Docket 5000323	3,760,750		3,760,750	
5					
6	Fees paid for Diablo Canyon Power Plant				
7	for inspection, license renewal, operator				
8	examination in accordance with Part 170				
9	Docket 5000275	2,445,734		2,445,734	
10	Docket 5000275	86,697		86,697	
11	Docket 5000323	2,328,094		2,328,094	
12	Docket 5000323	57,798		57,798	
13	General Accrual	-167,523		-167,523	
14	General Accrual	169,058		169,058	
15					
16	Fees paid for Diablo Canyon Power Plant				
17	for inspection, license renewal, operator				
18	examination in accordance with Part 171				
19	General Accrual	-40,000		-40,000	
20	General Accrual				
21					
22	Fees paid for Diablo Canyon Power Plant				
23	for inspection, license renewal, operator				
24	examination in accordance with Part 171				
25	Docket 5000133	140,500		140,500	
26					
27	*All paid to US Nuclear Regulatory Commission				
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	12,541,858		12,541,858	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
	524	3,760,750					3
	524	3,760,750					4
							5
							6
							7
							8
	524	2,445,734					9
	930	86,697					10
	524	2,328,094					11
	930	57,798					12
	524	-167,523					13
	930	169,058					14
							15
							16
							17
							18
	524	-40,000					19
	930						20
							21
							22
							23
							24
	524	140,500					25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		12,541,858					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	A2, A3	Electric Program Investment Charge
2		
3		
4		
5		
6	A2, A3	Customer Energy Services -
7		Cyber Security and Grid Innovation
8		
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		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
8,886,301		408	57,024		1
		456			2
		588	8,652,665		3
		916	176,613		4
					5
1,550,635					6
		408	9,568		7
		588	1,511,065		8
		908			9
		926	30,002		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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	294,340,053		
4	Transmission	84,222,063		
5	Regional Market			
6	Distribution	161,579,721		
7	Customer Accounts	111,502,453		
8	Customer Service and Informational	47,560,488		
9	Sales	506,080		
10	Administrative and General	405,305,316		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	1,105,016,174		
12	Maintenance			
13	Production	109,843,438		
14	Transmission	59,535,377		
15	Regional Market			
16	Distribution	241,176,049		
17	Administrative and General	86		
18	TOTAL Maintenance (Total of lines 13 thru 17)	410,554,950		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	404,183,491		
21	Transmission (Enter Total of lines 4 and 14)	143,757,440		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	402,755,770		
24	Customer Accounts (Transcribe from line 7)	111,502,453		
25	Customer Service and Informational (Transcribe from line 8)	47,560,488		
26	Sales (Transcribe from line 9)	506,080		
27	Administrative and General (Enter Total of lines 10 and 17)	405,305,402		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,515,571,124		1,515,571,124
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	2,506,692		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	7,022,715		
35	Transmission	85,467,852		
36	Distribution	169,810,865		
37	Customer Accounts	71,466,311		
38	Customer Service and Informational	10,807,373		
39	Sales	490,317		
40	Administrative and General	197,468,800		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	545,040,925		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)	89,783		
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,190,007		
47	Transmission	57,488,800		

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	99,230,271		
49	Administrative and General	42		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	157,998,903		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	2,596,475		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	8,212,722		
56	Transmission (Lines 35 and 47)	142,956,652		
57	Distribution (Lines 36 and 48)	269,041,136		
58	Customer Accounts (Line 37)	71,466,311		
59	Customer Service and Informational (Line 38)	10,807,373		
60	Sales (Line 39)	490,317		
61	Administrative and General (Lines 40 and 49)	197,468,842		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	703,039,828		703,039,828
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	2,218,610,952		2,218,610,952
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	904,207,510		904,207,510
69	Gas Plant	365,755,825		365,755,825
70	Other (provide details in footnote):	104,940,835		104,940,835
71	TOTAL Construction (Total of lines 68 thru 70)	1,374,904,170		1,374,904,170
72	Plant Removal (By Utility Departments)			
73	Electric Plant	67,697,409		67,697,409
74	Gas Plant	27,850,679		27,850,679
75	Other (provide details in footnote):	259,659		259,659
76	TOTAL Plant Removal (Total of lines 73 thru 75)	95,807,747		95,807,747
77	Other Accounts (Specify, provide details in footnote):			
78	Other Balance Sheet Salaries and Wages	12,828,121		12,828,121
79	Other Non-Operating Salaries and Wages	46,035,725		46,035,725
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	58,863,846		58,863,846
96	TOTAL SALARIES AND WAGES	3,748,186,715		3,748,186,715

COMMON UTILITY PLANT AND EXPENSES

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

COMMON UTILITY PLANT IN SERVICE

Acct No.	Description	Balance Beginning of Year	Additions	Retirements	Transfers and Adjustments	Balance End of Year
301	Organization	132,411	0	0	0	132,411
302	Franchises/Consents	214,735	0	0	0	214,735
303	Intangible Plant	1,594,715,290	198,580,748	(194,379,419)	0	1,598,916,619
	Total Intangible Plant	1,595,062,436	198,580,748	(194,379,419)	-	1,599,263,765
389	Land and Land Rights	104,359,435	145,581	0	-	104,505,016
390	Structures and Improvements	1,831,416,206	290,024,358	(31,666,826)	(47,185)	2,089,726,553
391	Personal Computer Hardware	72,937,621	6,048,786	(17,835,408)	0	61,150,999
391	Office Machines	321,444,766	41,101,969	(36,063,692)	0	326,483,043
391	Office Furniture and Equipment	121,228,092	7,688,126	(3,015,942)	0	125,900,276
392	Transportation Equipment	1,080,550,182	56,110,279	(24,433,906)	0	1,112,226,555
393	Stores Equipment	9,716,322	1,194,030	(54,451)	0	10,855,901
394	Tools, Shop, and Garage Equipment	69,787,512	1,133,295	0	0	70,920,807
395	Laboratory Equipment	13,423,446	21,138	(62,334)	0	13,382,250
396	Power Operated Equipment	177,084,091	20,386,531	(6,806,614)	0	190,664,008
397	Communication Equipment	1,216,428,516	82,425,211	(40,401,415)	(405,965)	1,258,046,347
398	Miscellaneous Equipment	28,708,867	12,573,892	(635,953)	0	40,646,806 (a)
399	Other Tangible Property	679	0	0	0	679
	Total Non-Landed	4,942,726,300	518,707,615	(160,976,541)	(453,150)	5,300,004,224
	Total	6,642,148,171	717,433,944	(355,355,960)	(453,150)	7,003,773,005
101	Property Under Capital Leases	18,230,721	0	0	96,081,349	114,312,070 (b)

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.

101 Plant Purchased/Sold	0	0	0	(42,345)	(42,345)
Total Common Utility Plant in Service	6,660,378,892	717,433,944	(355,355,960)	95,585,853	7,118,042,730
107 Construction Work in Progress - Common Utility Plt.	488,279,477	(223,489,506)	0	5,975,849	270,765,820
Total Common Utility Plant	7,148,658,369	493,944,438	(355,355,960)	101,561,702	7,388,808,550

NOTES:
(a) Included in the 12/31/19 FERC account 398 plant balance is $25,508,603 in Operative CWIP. Operative CWIP is defined as capital orders that are less than 30 days of construction that remain in CWIP due to capital order settlement issues. Capital orders that are less than 30 days of construction should be classified as plant. Since we may not know the final settlement of operative CWIP orders, FERC account 398 is chosen as a temporary settlement until these orders have valid settlement rules.

(b) The $96,081,348 transfer in Property Under Capital Leases reflects the Company’s adoption of ASC 842 on January 1, 2019 and represents the ASC 842 Operating Leases.

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)	7,118,042,729	4,605,943,089	2,512,099,640
Accumulated Provision for Depreciation (a)	2,988,123,518	1,931,821,854	1,056,301,664

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)	491,258,314	357,552,250	133,706,064

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.

(from page 262-263)			
Common Utility Plant (a)	42,620,260	27,578,718	15,041,542
included in above amount			

NOTES:

(a) 2019 allocations are based on the methodology of unbundling Common Plant as approved in the cost separation filing and adopted in the 2017 General Rate Case (GRC).

	Electric	Gas
Common Plant in Service Allocation Factors	64.71%	35.29%
Common Plant Accumulated Depreciation Allocation Factors	64.65%	35.35%

(b) Amounts are based on direct charges. Not included in the total was $0 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	238,240,654	154,022,583	84,218,071
Amortization	404	262,361,208	169,616,521	92,744,687
Total		500,601,863	323,639,104	176,962,758

ALLOCATION OF MAINTENANCE EXPENSES OF COMMON UTILITY PLANT BASED ON THE COST SEPARATION ADOPTED 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	03/25/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

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

Description	Amount Charged During Year	Account 935 Electric	Account 935 Gas
Maintenance of General Plant	6,289,696	4,229,191	2,060,504

Note: Operation expense data was not available.

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

Description of Project		Amount
7093891	ADMS Phase 0 Cap	10,639,193
7093670	CSO AMAG Security Upgrades (75 Sites)	10,026,780
70036182	CC2020 Salesforce - Cap	9,005,012
70035445	IO - SmartMeterSSN Transition PG&E (CAP)	8,834,496
70038246	FAN Field Area Network	7,131,900
70035024	ST-Web Acc Mgmt (CA Sitemndr) Rep (CAP)	6,944,700
7094845	Concord SC - Building A Restack	6,705,180
7092246	Antioch/Oakland SC - Security - Area 2	6,170,495
70033583	OP: AMSM-Asset Mgmt Pltfrm & Srvcs (AMPS	5,661,065
70038544	MRAD 3.0 Platform Cap	5,075,371
7091574	Network Improvements - Add Alternate	5,018,329
7089806	Bay Area Office Optimization	4,499,411
7091108	Materials & Spoils Bay Covers	4,076,308
70038505	Inspect and Engage (GRCED) - Cap	3,738,591
70036204	CCSF - (CAP)	3,711,121
70036261	Trans Support Structures (C) TO	3,559,762
70030413	Cyber: Windows XP Migration CAP Transmis	3,402,998
70038081	Lifecycle 2019 Cyber Security Network Pr	3,255,340
70036021	Data Security Data De-Identification (Ca	3,155,637
7090505	Corp Security-Replacement of Legacy CCTV	3,132,776
70033741	Express Connects Cap	2,874,748
70039805	IAM Platform Refresh (Sailpoint) CAP	2,832,539
70033756	Bentley SAP Integration - Phase3	2,724,070
70038048	IO - Smart Meter Field Assets Lifecycle	2,651,647
70036222	Cybersecurity	2,604,141
70038507	Inspect and Maintain ET - Cap	2,549,500
70037483	ARAD 4.0 CAP	2,529,466
70035502	ST - 2018 Firewall Lifecycle (Cap)	2,528,842
7090825	Corp Security-SIS Replacement-Capital	2,442,717
70036143	EES Ph2 (CAP)	2,426,437
70038508	Inspect and Maintain GD - Cap	2,416,337

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

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

70038647	IAM-Identity and Access Review Improveme	2,368,185
74017099	Hat Creek Network Extension	2,352,416
70038506	Inspect and Engage GT&S - Cap	2,343,244
70037326	CWSP: Veg Mgt Next Priority Insights CAP	2,260,526
74018957	FBS Upgrade	2,257,020
7095385	Placerville SC - Fence Replacement	2,201,155
70038501	STAR for Transmission Line CAP	2,193,392
70039481	PCAP and Passive Vulnerability Scanning	2,003,602
7090325	Auburn SC Regional GC Conversion	1,967,563
7092805	Fresno Thorne Avenue - Develop OU-3	1,825,326
7091573	GDCC Predictive Health Analytics	1,804,477
70037720	IO - D305 - D306 DMW Replacement	1,795,690
7094825 ERF	Consent Decree Treatd Wood Storage	1,767,175
70038043	CWSP: PSPS Field Inspection Application	1,744,886
74017092	DCPP Replace EDMS/RMS/Filenet PH3	1,739,515
70038101	IO - 2019 Switch Lifecycle	1,728,194
74023500	MII Initiatives 2019	1,708,122
70038240	SCADA Mountain Tops Radios	1,658,025
70037921	IO - Total Cost of Ownership (Cap)	1,641,525
74022340	SQMD Replacement Gen (Cap)	1,632,920
7095405	Chico SC - Fence Replacement	1,597,347
70039040	EGI 2019 Tariff Changes CAP	1,581,084
70038432	IO - DSO Conversion to MPLS/TSRP	1,516,412
70036362	Extnd PwrBase Line Equip SetMgmt	1,510,385
70036027	Data Security Metrics, Inventory, Owners	1,452,107
70029346	Wesley Fiber Install	1,297,488
7092947	Fremont Materials UST remvoe AST Instal	1,242,742
70036360	CYME LoadSEER and EDPI Integration	1,236,578
7094732	GD/GT-GIS Upgrade 2019	1,234,472
70039104	DCPP-EOF Telephone System Rplcmnt Ph 2	1,079,353
7096105	DCC ADMS Development Environment	985,996
7091575	Network Improvements - Improve WAN	968,770
7094727	GD/GT-GIS Upgrade 2019	949,624
70033562	Hughes Satellite Terminal Replacement	939,267
70035447	DCPP Network Switch and WiFi Replacement	929,996
7095225	Angels Camp SC-Generator/ATS Replacement	926,911
74017106	Kings-Crane Grounding and Bonding	921,582
74017115	DCPP Remediate Vulnerable Operating Sys	885,053
70038825	MTC: Cust Rate - Agricult Rte Redsgn (C)	882,838
70038421	IO - Windows 2003-2008 LC ODN GT - CAP	866,740
7083729	TO Radio System Expansion - Gato Ridge	858,656
70033814	BENTLEY-SAP INTEGRATION DISTRIBUTIVE ENG	856,654
70038680	CONSTRUCT ED RELEASE 2.0 (CAP)	850,043
70038503	STAR for ED Hardening CAP	845,860
70035662	DC - OSI PI Platform Capacity Phase 3 -	844,299
70036150	ET Asset Registry - (CAP)	842,434

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

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

7091968	VCOC - B2 (IT Infra)_I	842,181
7095328	Dinuba SC Fence Replacement	828,334
70036680	Lifecycle Active Directory (Cap)	817,451
7095645	Angels Camp SC-Erosion Control/Drainage	801,202
74017097	Power Gen Records Management - cap	788,991
74017114	PGEN Station Tech Upgrade Program	786,502
7088763	Electric Storage Containers	785,371
7094148	Ecological Righs Fundation	772,882
7095209 ODN	Infrastructure 1009	772,638
70039280	CWSP - Construct App (Cap TO)	772,356
70037127	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP TO	747,686
70037128	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP ED	747,686
70037129	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP GD	747,686
70037130	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP IT	747,686
70037131	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP HG	747,686
70036029	IO-Vulnerable Anlg Line Gateway Lifecyle	740,703
70037088	IGP - SCADA -ODN Upgrades	736,774
70036741	IO - WIFI Everywhere-Field Ph 2 - W3	736,682
7093545	ESP Improvement Project	733,470
74023501	MII ESDER 3 2019 (C)	693,523
74017111	Wireless Enhancements - Feather	678,199
7095210	ODN Network Protection 1009	674,139
70037124	Moraga Sub SPOF	662,852
70040466	CWSP: PSPS Viewer_OMT_ESF (Cap)	656,777
7095726	SIPT - Capital equipment	654,217
70036207	IO - Harris DVM-xT & NEC MW Lifecycle	648,931
74017109	Copper Fiber Replacement - Battle Creek	647,821
7093169	FFIOC-Install Emergency Power Off (EPO)	639,726
70038960	Lifecycle Security Logging and Monitorin	635,460
7095725	PSPS Capital Equipment - Radio Hardware	627,459
7094145	San Fran SC - AST Civile Dsgn Equipment	601,557
70035960	IO-SCADA Radio Cap Reliablty Imrv (TO)	586,464
70038245	FAN SCADA Leases	568,416
70040221	Sherlock Tool 2.0(C) TO	564,640
70033129	NEM 2.0 Customer Bill Presentment Cap	557,637
70033549	Cyber SS ST - 3rd Party Security and Ris	554,058
70027586	Radio Reliability - Lime Mt	547,195
7094665	Gas SCADA Upgrade	539,917
70040222	Sherlock Tool 2.0 (C) DIST	525,306
70033771	OP: AMSM - Enterprise Network Mgmt Syst	518,828
7096027	Vaca-Dixon North 500KV Yard Upgrade	505,142
70038682	CONSTRUCT GD RELEASE 2.0 (CAP)	504,699
70034622	Hinkley Comp Station Ntwrk Remediation	495,032
70033147	Pole Loading Tool Upgrade with Industry	481,544
70039561	DC Consolidation: CDW Server Upgrade	466,599
70033563	IO - SCADA Power Reliability: TES Facili	455,835

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

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

70032800	Battle Creek - VSAT Emergency Phones	449,269
70032303	Bentley-SAP Integration CAP ED	448,414
7095907	SRVCC - 2019 Misc Upgrade Projects	445,426
74019740	RPM Wave 2 CAP	444,843
70035929	User Behavior Analytics Cap GRC	427,704
70038430	DC - Windows 2003-2008 Lifecycle UDN	427,203
70035931	User Behavior Analytics Cap TO	425,024
7092166	Software & Servers	422,522
70037126	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP GT	415,381
74017108	Kings-Crane Network Extension	382,358
70036380	IO - SCADA Power Reliability: Table Mtn.	360,885
7095826	DCC Network Upgrade-Fresno	359,111
70036208	IO -Develop Fiber Mux Platform to Replac	354,345
70037087	IGP - SCADA - Communication Updgrade	353,692
70036212	IO - VTC Infrastructure Upgrade Project	348,698
70037243	IO - SCADA Power Reliability: Santa Rosa	340,659
7091752	Auburn Garage - Two Lifts	336,761
70038827	MTC: Cust Rate - Agricult New TOU (C)	331,436
70029581	EMS SMP Server Replacement	330,137
7094666	Gas SCADA Upgrade	329,138
7094225	ST - PHYS AMAG SFGO Jump Hosts	327,401
7095207	ODN Physical Security 1009	319,731
70038243	SCADA Communication Failures	316,245
74017103	Drum - VoIP	315,999
7089965	Livermore Sub Training - New Facility	311,192
7094731	Operator Training Simulator	304,046
70037081	IGP - SCADA - Leases	301,537
7091750	30k Drive on Hoist	293,923
70037242	IO - SCADA Power Reliability: Metcalf Su	285,683
70037244	IO - SCADA Power Reliability: Vaca Dixon	285,268
7094412	Break Replace Fairfield SOC Workstations	284,359
7094646	EM Tool 2019-2020	280,979
7095345	DCC Network Upgrade Concord	275,295
7094987	WSIP - Novato Area Laydown Yard	270,008
70040465	WIV Wildfire Incident Viewer Prod (Cap)	269,208
70035927	User Behavior Analytics Cap GT&S	269,169
7094726	Operator Training Simulator	266,417
70031540	Hydro HVP Program	265,393
70038565	IO - Los Banos to Merced SC MW Cir Rmv	264,472
7094647	EM Tool 2019-2020	264,170
74017101	Helms T1 Gate House Telecom Path	255,253
70035948	IO - ODN Switch Router Lifecycle (TO)	254,939
7093825	SF Auditorium Project	252,324

Subtotal - Projects with more than $250,000
in actual costs in CWIP, excluding Research,

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

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

```
  Development, & Demonstration jobs                         $254,032,515


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

                                                             $16,733,305

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

          TOTAL CWIP - COMMON                               $ 270,765,820
```

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	25,054,276	31,143,870	47,218,123	137,516,767
3	Net Sales (Account 447)	(204,044,881)	(75,574,553)	(162,857,598)	(586,377,238)
4	Transmission Rights				
5	Ancillary Services	(7,135,311)	(1,835,827)	(3,501,281)	(16,021,736)
6	Other Items (list separately)				
7	Grid Management Charges	9,558,121	10,227,557	11,903,938	40,064,906
8	FERC Fees	785,681	683,519	1,092,930	3,168,441
9	ISO Congestion				
10	Unaccounted for Energy	1,354,709	(13,296,119)	(10,906,802)	(25,960,574)
11	Congestion Revenue Rights-Hedge	(7,984,562)	(15,023,359)	(6,402,081)	(37,828,254)
12	Congestion Revenue Rights-Auction	(14,405)			(14,405)
13	Convergence Bidding				
14	Other ISO-related charges:				
15	Minimum Load				
16	Neutrality	(59,447)	112,421	141,180	206,367
17	Voltage Support				
18	Other	2,650,200	(820,004)	1,676,191	3,542,189
19	Cost Recovery	(3,657,810)	(1,831,556)	907,688	(5,860,131)
20	Inter Day Ahead SC Trade				
21	Inter Real Time SC Trade				
22	Interest	86,998	(112,430)	97,027	69,805
23	Capacity - Other	1,814,899	4,124,921	1,995,559	10,822,267
24	DA IFM Credit Allocation	(7,892,573)	(5,430,253)	(10,657,824)	(30,004,414)
25	RT Offset/Allocation	1,497,248	3,627,998	4,517,726	19,388,101
26	Net Purchases for Energy Storage	62,595	(1,276)	15,224	142,788
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(187,924,262)	(64,005,091)	(124,760,000)	(487,145,121)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	
2	Reactive Supply and Voltage					kW-Month	
3	Regulation and Frequency Response					kW-Month	
4	Energy Imbalance					kWh	
5	Operating Reserve - Spinning					kW-Month	
6	Operating Reserve - Supplement					kW-Month	
7	Other		Various	74,161		Various	16,095,898
8	Total (Lines 1 thru 7)			74,161			16,095,898

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

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

Schedule Page: 398 Line No.: 7 Column: b

This line includes Ancillary Services as follows:

AS under grandfathered existing contracts						
Regulation Service Charge	-	-	-		Flat Charge	0
ISO related AS activities						
Retail/BART ISO Purchases and Sales and Existing Transmission Contracts (ETC) (a)	-	Various	74,161	-	Various	16,095,898
Total			74,161			16,095,898

(a) This comprised of various billing determinants which the ISO uses to calculate the amounts of AS sold or purchased. This item also includes ISO AS purchases/sales by the Utility in its role as Scheduling Coordinator for ETCs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	13,028	2	1900	4,980			100		7,948
2	February	13,728	12	1900	5,838			100		7,790
3	March	12,557	7	1900	5,029			50		7,478
4	Total for Quarter 1				15,847			250		23,216
5	April	14,945	24	1900	6,434			100		8,411
6	May	13,140	31	2100	6,277			75		6,788
7	June	20,009	11	1900	9,342			100		10,567
8	Total for Quarter 2				22,053			275		25,766
9	July	18,826	24	1900	8,928			50		9,848
10	August	20,843	15	1900	9,824			75		10,944
11	September	19,171	25	1800	7,915			100		11,156
12	Total for Quarter 3				26,667			225		31,948
13	October	14,194	7	1900	5,646			100		8,448
14	November	13,431	26	1400	4,061			100		9,270
15	December	13,712	16	1900	5,030			100		13,612
16	Total for Quarter 4				14,737			300		31,330
17	Total Year to Date/Year				79,304			1,050		112,260

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.: 10 Column: j

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: j

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

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

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

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

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

Transmission services utilizing the Utility's transmission system are also sold by the California Independent System Operator ("ISO") to other wholesale entities. The ISO tracks this data and reports it separately to the FERC. The Utility does not have access to this data. The ISO numbers reported in this column were derived by subtracting columns (e)-(i) from column (b).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	5,901,402
4	Nuclear	16,165,387
5	Hydro-Conventional	11,021,212
6	Hydro-Pumped Storage	744,444
7	Other	701,629
8	Less Energy for Pumping	1,042,987
9	Net Generation (Enter Total of lines 3 through 8)	33,491,087
10	Purchases	42,164,686
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	524,276
17	Delivered	514,362
18	Net Transmission for Other (Line 16 minus line 17)	9,914
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	75,665,687
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	36,762,729
23	Requirements Sales for Resale (See instruction 4, page 311.)	21,907,744
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	16,995,214
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	75,665,687

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	6,832,153		11,651	2	1900
30	February	6,192,906		12,266	12	1900
31	March	6,188,960		10,897	7	2000
32	April	6,148,175		13,197	24	1900
33	May	6,397,429		11,735	31	2100
34	June	7,444,640		17,848	11	1900
35	July	8,182,834		16,907	24	1900
36	August	8,601,055		18,731	15	1900
37	September	7,490,392		16,925	25	1800
38	October	6,641,120		12,555	7	1900
39	November	6,471,973		11,809	26	1400
40	December	7,233,903		12,169	16	1900
41	TOTAL	83,825,540				

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

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

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

This line includes internal combustion reciprocating engines, photo voltaic and Fuel Cells. This includes photo voltaic generation of 282,730 MWh.

Schedule Page: 401 Line No.: 10 Column: b

For purposes only of accounting for the total energy that went through the Utility's electric system, the MWH for Direct Access ("DA") is **41,609,487 MWH.** It should be noted that DA and DWR megawatts are not Utility purchases and were reported here only because page 401 of the Form 1 does not have any other available line where DA and DWR deliveries can be shown more appropriately.

The Utility acts as a pass-through entity for electricity purchased by the DWR that is sold to the Utility's customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from electricity revenue amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers, priced at the related CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Statement of Income.

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *DIABLO CANYON 1 & 2* (b)	Plant Name: *Colusa Gen Station* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Combined Cycle
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Outdoor
3	Year Originally Constructed	1968	2010
4	Year Last Unit was Installed	1986	2010
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2323.00	711.45
6	Net Peak Demand on Plant - MW (60 minutes)	2240	657
7	Plant Hours Connected to Load	8760	6007
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	1277	22
12	Net Generation, Exclusive of Plant Use - KWh	16165386861	3028543454
13	Cost of Plant: Land and Land Rights	22726560	7889274
14	Structures and Improvements	1092025267	116308612
15	Equipment Costs	6845917674	544933579
16	Asset Retirement Costs	2701010462	3912558
17	Total Cost	1.066E+10	673044023
18	Cost per KW of Installed Capacity (line 17/5) Including	4589.6169	946.0173
19	Production Expenses: Oper, Supv, & Engr	4915613	87946
20	Fuel	113567860	75535359
21	Coolants and Water (Nuclear Plants Only)	35186370	0
22	Steam Expenses	41818534	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	4021766	4005732
26	Misc Steam (or Nuclear) Power Expenses	215981064	1107723
27	Rents	0	0
28	Allowances	0	15818296
29	Maintenance Supervision and Engineering	2623727	19973
30	Maintenance of Structures	4274664	2037063
31	Maintenance of Boiler (or reactor) Plant	31444584	890623
32	Maintenance of Electric Plant	42240924	2797427
33	Maintenance of Misc Steam (or Nuclear) Plant	115868215	2322772
34	Total Production Expenses	611943321	104622914
35	Expenses per Net KWh	0.0379	0.0345

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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	2038710	0	0	129091	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	1043917	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	4.440	0.000	0.000
41	Average Cost of Fuel per Unit Burned	55.462	0.000	0.000	6.170	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.680	0.000	0.000	0.040	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10327.780	0.000	0.000	44.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

Plant Name: *Gateway Gen Station* (d)			Plant Name: *Humboldt Gen Station* (e)			Plant Name: (f)			Line No.
Combined Cycle			Internal Combustion						1
Outdoor			Indoor						2
2009			2010						3
2009			2011						4
619.65			162.70			0.00			5
580			163			0			6
6310			8719			0			7
0			0			0			8
0			0			0			9
0			0			0			10
22			18			0			11
2872858115			405140461			0			12
5040000			161399			0			13
72554609			67489321			0			14
385339678			153852335			0			15
3004029			1925852			0			16
465938316			223428907			0			17
751.9379			1373.2570			0			18
87946			26982			0			19
71043132			10367775			0			20
0			0			0			21
10488			0			0			22
0			0			0			23
0			0			0			24
3641050			3132252			0			25
737202			1260645			0			26
0			0			0			27
15273575			2609469			0			28
19973			6127			0			29
27002			372591			0			30
1179492			122360			0			31
3433650			3071266			0			32
1183391			0			0			33
96636901			20969467			0			34
0.0336			0.0518			0.0000			35
Gas			Oil	Gas					36
MCF			BBL	MCF					37
19801685	0	0	4775	3382095	0	0	0	0	38
1043333	0	0	5763124	1043667	0	0	0	0	39
4.550	0.000	0.000	116.570	4.150	0.000	0.000	0.000	0.000	40
4.750	0.000	0.000	115.250	5.340	0.000	0.000	0.000	0.000	41
4.550	0.000	0.000	20.000	5.120	0.000	0.000	0.000	0.000	42
0.030	0.000	0.000	0.140	0.050	0.000	0.000	0.000	0.000	43
7191.000	0.000	0.000	8089.000	8885.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 1 (b)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1927	1958
4	Year Last Unit was Installed	1927	1958
5	Total installed cap (Gen name plate Rating in MW)	31.00	97.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	105
7	Plant Hours Connect to Load	8,346	8,433
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	162,913,441	581,100,158
13	Cost of Plant		
14	Land and Land Rights	8,149	2,588
15	Structures and Improvements	852,177	5,184,297
16	Reservoirs, Dams, and Waterways	9,591,857	6,910,338
17	Equipment Costs	9,804,003	39,473,167
18	Roads, Railroads, and Bridges	1,327,743	1,738,622
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	21,583,929	53,309,012
21	Cost per KW of Installed Capacity (line 20 / 5)	696.2558	548.4466
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	8,094	15,892
25	Hydraulic Expenses	125	387
26	Electric Expenses	87,292	160,353
27	Misc Hydraulic Power Generation Expenses	134,994	352,034
28	Rents	99	305
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	4,629	41,943
31	Maintenance of Reservoirs, Dams, and Waterways	141,301	457,466
32	Maintenance of Electric Plant	271,685	842,216
33	Maintenance of Misc Hydraulic Plant	168,375	402,199
34	Total Production Expenses (total 23 thru 33)	816,594	2,272,795
35	Expenses per net KWh	0.0050	0.0039

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	5,096	8,172
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	41	75
10	(b) Under the Most Adverse Oper Conditions	38	74
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	129,758,354	129,026,245
13	Cost of Plant		
14	Land and Land Rights	424,515	339,180
15	Structures and Improvements	5,360,835	7,542,261
16	Reservoirs, Dams, and Waterways	36,875,909	28,816,633
17	Equipment Costs	20,510,838	32,976,375
18	Roads, Railroads, and Bridges	3,314,275	5,525,204
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	66,486,372	75,199,653
21	Cost per KW of Installed Capacity (line 20 / 5)	1,662.1593	1,018.2756
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	143,469	259,929
25	Hydraulic Expenses	3,178	4,437
26	Electric Expenses	240,027	1,184,416
27	Misc Hydraulic Power Generation Expenses	178,981	179,747
28	Rents	1,919	3,501
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	23,091	63,005
31	Maintenance of Reservoirs, Dams, and Waterways	577,863	301,072
32	Maintenance of Electric Plant	1,034,866	492,683
33	Maintenance of Misc Hydraulic Plant	67,983	34,982
34	Total Production Expenses (total 23 thru 33)	2,271,377	2,523,772
35	Expenses per net KWh	0.0175	0.0196

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 803 Plant Name: DE SABLA (b)	FERC Licensed Project No. 2310 Plant Name: DRUM NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1963	1913
4	Year Last Unit was Installed	1963	1928
5	Total installed cap (Gen name plate Rating in MW)	18.45	49.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	19	54
7	Plant Hours Connect to Load	5,952	5,107
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	19	54
10	(b) Under the Most Adverse Oper Conditions	19	54
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	50,603,719	72,318,388
13	Cost of Plant		
14	Land and Land Rights	145,606	1,583,354
15	Structures and Improvements	3,272,933	5,574,086
16	Reservoirs, Dams, and Waterways	42,060,043	41,133,403
17	Equipment Costs	6,605,159	24,698,915
18	Roads, Railroads, and Bridges	4,428,289	1,440,177
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	56,512,030	74,429,935
21	Cost per KW of Installed Capacity (line 20 / 5)	3,062.9827	1,512.8036
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	4,555	46,407
25	Hydraulic Expenses	2,360	21,174
26	Electric Expenses	316,173	344,018
27	Misc Hydraulic Power Generation Expenses	510,255	256,244
28	Rents	2,547	22,957
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	41,202	166,874
31	Maintenance of Reservoirs, Dams, and Waterways	1,033,358	480,973
32	Maintenance of Electric Plant	77,712	268,008
33	Maintenance of Misc Hydraulic Plant	134,731	22,029
34	Total Production Expenses (total 23 thru 33)	2,122,893	1,628,684
35	Expenses per net KWh	0.0420	0.0225

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1988 Plant Name: HAAS (b)	FERC Licensed Project No. 2130 Plant Name: HALSEY (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1958	1916
4	Year Last Unit was Installed	1958	1916
5	Total installed cap (Gen name plate Rating in MW)	135.00	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	144	11
7	Plant Hours Connect to Load	8,432	7,100
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	649,526,901	41,230,238
13	Cost of Plant		
14	Land and Land Rights	27,861	1,060,230
15	Structures and Improvements	11,018,265	3,015,905
16	Reservoirs, Dams, and Waterways	28,242,746	29,435,939
17	Equipment Costs	41,432,801	10,981,701
18	Roads, Railroads, and Bridges	734,083	287,972
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	81,455,756	44,781,747
21	Cost per KW of Installed Capacity (line 20 / 5)	603.3760	3,292.7755
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	19,679	10,806
25	Hydraulic Expenses	531	1,538
26	Electric Expenses	210,522	479,854
27	Misc Hydraulic Power Generation Expenses	821,108	72,120
28	Rents	25,510	5,346
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	75,977	39,465
31	Maintenance of Reservoirs, Dams, and Waterways	525,863	377,735
32	Maintenance of Electric Plant	609,739	366,856
33	Maintenance of Misc Hydraulic Plant	74,911	214,143
34	Total Production Expenses (total 23 thru 33)	2,363,840	1,567,863
35	Expenses per net KWh	0.0036	0.0380

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 2 (b)	FERC Licensed Project No. 1988 Plant Name: KINGS RIVER (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Underground	Semi-Outdoor
3	Year Originally Constructed	1983	1962
4	Year Last Unit was Installed	1983	1962
5	Total installed cap (Gen name plate Rating in MW)	139.50	48.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	155	52
7	Plant Hours Connect to Load	7,746	4,719
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	668,409,199	121,959,443
13	Cost of Plant		
14	Land and Land Rights	584,722	18,738
15	Structures and Improvements	39,041,065	6,048,349
16	Reservoirs, Dams, and Waterways	90,591,145	21,542,468
17	Equipment Costs	52,573,755	23,677,596
18	Roads, Railroads, and Bridges	7,536,634	418,743
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	190,327,321	51,705,894
21	Cost per KW of Installed Capacity (line 20 / 5)	1,364.3536	1,063.9073
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	113,443	9,841
25	Hydraulic Expenses	0	192
26	Electric Expenses	181,459	107,290
27	Misc Hydraulic Power Generation Expenses	177,706	308,167
28	Rents	65	9,213
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	44,774	2,294
31	Maintenance of Reservoirs, Dams, and Waterways	102,638	189,810
32	Maintenance of Electric Plant	565,772	573,227
33	Maintenance of Misc Hydraulic Plant	53,100	7,412
34	Total Production Expenses (total 23 thru 33)	1,238,957	1,207,446
35	Expenses per net KWh	0.0019	0.0099

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 233 Plant Name: PIT NO. 3 (b)	FERC Licensed Project No. 233 Plant Name: PIT NO. 4 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1955
4	Year Last Unit was Installed	1925	1955
5	Total installed cap (Gen name plate Rating in MW)	80.19	103.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	70	95
7	Plant Hours Connect to Load	8,739	8,732
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	70	95
10	(b) Under the Most Adverse Oper Conditions	70	95
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	362,290,430	452,907,898
13	Cost of Plant		
14	Land and Land Rights	3,830,927	299,494
15	Structures and Improvements	9,397,890	4,003,474
16	Reservoirs, Dams, and Waterways	68,744,482	40,928,039
17	Equipment Costs	45,430,998	38,019,689
18	Roads, Railroads, and Bridges	7,626,094	3,742,964
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	135,030,391	86,993,660
21	Cost per KW of Installed Capacity (line 20 / 5)	1,683.8807	840.5185
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	55,474	64,794
25	Hydraulic Expenses	52,591	57,203
26	Electric Expenses	463,690	307,415
27	Misc Hydraulic Power Generation Expenses	420,392	442,530
28	Rents	5,240	5,240
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	4,566	5,184
31	Maintenance of Reservoirs, Dams, and Waterways	48,061	32,877
32	Maintenance of Electric Plant	289,815	910,395
33	Maintenance of Misc Hydraulic Plant	98,680	49,991
34	Total Production Expenses (total 23 thru 33)	1,438,509	1,875,629
35	Expenses per net KWh	0.0040	0.0041

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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. 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	7,254	8,752
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	120	119
10	(b) Under the Most Adverse Oper Conditions	120	119
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	602,993,484	638,433,066
13	Cost of Plant		
14	Land and Land Rights	821,236	1,777,639
15	Structures and Improvements	4,106,468	21,640,770
16	Reservoirs, Dams, and Waterways	60,418,606	51,768,070
17	Equipment Costs	39,244,496	106,603,678
18	Roads, Railroads, and Bridges	2,020,272	354,704
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	106,611,078	182,144,861
21	Cost per KW of Installed Capacity (line 20 / 5)	746.4194	1,452.8584
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	2,192	2,192
25	Hydraulic Expenses	718,316	9,568
26	Electric Expenses	290,116	1,389,063
27	Misc Hydraulic Power Generation Expenses	609,982	1,366,796
28	Rents	9,268	10,292
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	32,825	114,458
31	Maintenance of Reservoirs, Dams, and Waterways	257,795	1,023,618
32	Maintenance of Electric Plant	189,041	96,639
33	Maintenance of Misc Hydraulic Plant	47,840	7,135
34	Total Production Expenses (total 23 thru 33)	2,157,375	4,019,761
35	Expenses per net KWh	0.0036	0.0063

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	7,537	7,789
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	14
10	(b) Under the Most Adverse Oper Conditions	13	14
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	77,987,478	71,413,642
13	Cost of Plant		
14	Land and Land Rights	146,626	805,956
15	Structures and Improvements	1,035,431	4,064,630
16	Reservoirs, Dams, and Waterways	6,541,796	17,491,499
17	Equipment Costs	7,360,339	10,706,740
18	Roads, Railroads, and Bridges	252,898	219,583
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,337,090	33,288,408
21	Cost per KW of Installed Capacity (line 20 / 5)	1,127.7272	2,447.6771
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	1,460	13,290
25	Hydraulic Expenses	35,693	0
26	Electric Expenses	168,830	1,157,475
27	Misc Hydraulic Power Generation Expenses	147,686	84,949
28	Rents	124	6,574
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	42,357	43,847
31	Maintenance of Reservoirs, Dams, and Waterways	156,323	398,134
32	Maintenance of Electric Plant	168,074	86,575
33	Maintenance of Misc Hydraulic Plant	19,260	6,845
34	Total Production Expenses (total 23 thru 33)	739,807	1,797,689
35	Expenses per net KWh	0.0095	0.0252

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
7,294	8,720	8,573	7
			8
125	172	65	9
125	172	53	10
0	0	0	11
429,602,964	679,594,766	15,804,192	12
			13
622,376	568,021	810,497	14
11,656,425	766,410	1,471,926	15
58,414,696	66,983,216	21,242,650	16
64,147,185	19,246,247	22,590,972	17
1,222,844	2,073,880	3,068,236	18
0	0	0	19
136,063,526	89,637,774	49,184,281	20
1,154.0587	531.4703	745.2164	21
			22
0	0	0	23
431,192	17,514	2,342	24
6,289	80,424	5,188	25
350,683	421,159	212,350	26
180,875	13,361	14,483,060	27
5,827	11,001	21,671	28
0	0	0	29
5,149	45,335	34,374	30
1,408,062	345,784	565,363	31
1,051,649	206,474	244,360	32
7,897	69,694	145,488	33
3,447,623	1,210,746	15,714,196	34
0.0080	0.0018	0.9943	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 2 (d)	FERC Licensed Project No. 1121 Plant Name: COLEMAN (e)	FERC Licensed Project No. 1962 Plant Name: CRESTA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1958	1979	1949	3
1958	1979	1950	4
117.90	12.15	73.80	5
120	13	70	6
7,995	6,722	8,324	7
			8
120	13	70	9
119	5	72	10
0	0	0	11
678,295,481	38,129,849	370,464,063	12
			13
368,710	178,368	1,365,044	14
11,148,985	1,700,751	11,409,460	15
36,006,624	23,699,882	22,949,504	16
34,322,089	13,327,674	14,752,645	17
466,734	606,296	135,437	18
0	0	0	19
82,313,142	39,512,971	50,612,090	20
698.1607	3,252.0964	685.8007	21
			22
0	0	0	23
414,066	973	2,192	24
6,104	2,554	8,724	25
306,975	308,746	219,067	26
182,203	289,149	838,467	27
5,594	380	5,718	28
0	0	0	29
57,630	48,189	49,945	30
234,657	270,541	697,053	31
172,552	50,009	313,771	32
1,146	34,486	25,778	33
1,380,927	1,005,027	2,160,715	34
0.0020	0.0264	0.0058	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2310 Plant Name: DRUM NO. 2 (d)	FERC Licensed Project No. 2310 Plant Name: DUTCH FLAT (e)	FERC Licensed Project No. 137 Plant Name: ELECTRA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1965	1943	1948	3
1965	1943	1948	4
53.10	22.00	102.50	5
50	22	98	6
8,114	6,614	7,418	7
			8
50	22	98	9
49	23	98	10
0	0	0	11
278,236,354	64,343,801	316,525,611	12
			13
430,040	824,865	755,502	14
1,120,931	2,688,139	2,815,745	15
11,848,366	20,705,684	31,028,804	16
8,182,164	16,553,628	31,221,749	17
483,694	748,202	1,397,489	18
0	0	0	19
22,065,195	41,520,518	67,219,289	20
415.5404	1,887.2963	655.7979	21
			22
0	0	0	23
42,681	19,913	175,917	24
19,051	22,607	176,690	25
301,269	365,405	482,626	26
237,001	119,404	757,144	27
21,114	9,851	639	28
0	0	0	29
135,123	62,483	164,655	30
434,742	336,452	456,653	31
125,092	121,051	340,779	32
20,728	16,885	122,322	33
1,336,801	1,074,051	2,677,425	34
0.0048	0.0167	0.0085	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2661 Plant Name: HAT CREEK NO. 1 (d)	FERC Licensed Project No. 2661 Plant Name: HAT CREEK NO. 2 (e)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1921	1921	1920	3
1921	1921	1920	4
10.00	10.00	22.72	5
9	9	25	6
7,831	8,443	0	7
			8
9	9	25	9
4	9	0	10
0	0	0	11
34,330,364	43,081,406	0	12
			13
776,743	714,826	6,947	14
755,824	284,147	1,651,020	15
2,777,825	1,887,052	3,356,290	16
3,907,861	3,625,827	6,167,437	17
1,178,247	390,980	6,175	18
0	0	0	19
9,396,500	6,902,832	11,187,869	20
939.6500	690.2832	492.4238	21
			22
0	0	0	23
0	0	22,018	24
1,568	1,568	0	25
142,648	146,135	94,378	26
10,972	10,972	53,542	27
75	75	11	28
0	0	0	29
6,735	7,510	39,270	30
21,162	41,307	20,537	31
66,471	33,164	25,797	32
41,479	46,740	8,638	33
291,110	287,471	264,191	34
0.0085	0.0067	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1403 Plant Name: NARROWS (d)	FERC Licensed Project No. 2310 Plant Name: NEWCASTLE (e)	FERC Licensed Project No. 2687 Plant Name: PIT NO.1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1942	1986	1922	3
1942	1986	1922	4
10.20	12.70	69.30	5
12	12	61	6
4,545	5,213	8,707	7
			8
12	12	61	9
12	0	61	10
0	0	0	11
46,919,994	21,264,751	277,395,601	12
			13
274,384	2,029,878	2,195,951	14
1,173,502	6,518,443	2,251,571	15
1,132,402	48,000,046	13,420,907	16
7,129,752	8,322,670	38,771,127	17
506,705	3,070,186	1,448,917	18
0	0	0	19
10,216,745	67,941,223	58,088,473	20
1,001.6417	5,349.7026	838.2175	21
			22
0	0	0	23
14,160	11,220	122,900	24
700	0	50,931	25
89,514	496,085	295,301	26
64,130	74,258	609,539	27
0	5,550	0	28
0	0	0	29
41,461	40,277	2,141	30
143,600	332,866	225,679	31
194,521	198,455	163,761	32
57,687	8,149	88,691	33
605,773	1,166,860	1,558,943	34
0.0129	0.0549	0.0056	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
8,760	7,856	8,621	7
			8
160	80	112	9
160	80	112	10
0	0	0	11
853,863,006	334,657,375	459,368,431	12
			13
661,690	382,453	328,634	14
20,223,720	6,605,001	6,744,744	15
46,181,081	35,115,658	31,466,544	16
91,377,662	15,350,442	13,713,743	17
9,127,279	687,387	406,208	18
0	0	0	19
167,571,432	58,140,941	52,659,873	20
1,181.4117	734.1028	479.5981	21
			22
0	0	0	23
0	17,514	17,514	24
69,192	54,790	69,248	25
727,754	344,598	366,475	26
500,089	262,719	291,055	27
5,240	11,001	11,001	28
0	0	0	29
-195,475	52,577	7,388	30
-212,936	138,555	152,086	31
378,001	724,771	301,086	32
81,459	54,518	39,514	33
1,353,324	1,661,043	1,255,367	34
0.0016	0.0050	0.0027	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 137 Plant Name: SALT SPRINGS (d)	FERC Licensed Project No. 2130 Plant Name: STANISLAUS (e)	FERC Licensed Project No. 137 Plant Name: TIGER CREEK (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Outdoor	Conventional	2
1931	1963	1931	3
1953	1963	1931	4
42.03	81.90	52.28	5
44	91	58	6
8,349	7,580	7,476	7
			8
44	91	58	9
34	91	58	10
0	0	0	11
191,524,665	376,753,050	252,441,024	12
			13
211,850	428,928	2,451,142	14
2,499,410	6,712,790	8,453,886	15
35,853,828	37,119,102	59,517,413	16
13,542,890	20,516,366	27,591,942	17
1,437,965	1,110,920	7,587,906	18
0	0	0	19
53,545,943	65,888,106	105,602,289	20
1,273.9934	804.4946	2,019.9367	21
			22
0	0	0	23
4,008	397,028	4,613	24
1,869,908	25,710	106,920	25
267,681	412,982	451,620	26
404,856	1,296,528	465,188	27
341	41,655	392	28
0	0	0	29
131,138	35,729	202,981	30
996,168	1,114,551	422,932	31
374,778	386,514	246,789	32
52,757	381,476	60,685	33
4,101,635	4,092,173	1,962,120	34
0.0214	0.0109	0.0078	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1354 Plant Name: A.G. WISHON (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
R of R/Storage			1
Conventional			2
1910			3
1910			4
12.80	0.00	0.00	5
20	0	0	6
5,647	0	0	7
			8
20	0	0	9
12	0	0	10
0	0	0	11
52,791,597	0	0	12
			13
974,379	0	0	14
1,519,510	0	0	15
50,238,506	0	0	16
6,407,687	0	0	17
29,462	0	0	18
0	0	0	19
59,169,544	0	0	20
4,622.6206	0.0000	0.0000	21
			22
0	0	0	23
6,217	0	0	24
0	0	0	25
143,149	0	0	26
1,516,465	0	0	27
17,967	0	0	28
0	0	0	29
10,731	0	0	30
75,322	0	0	31
225,955	0	0	32
125	0	0	33
1,995,931	0	0	34
0.0378	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

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

PACIFIC GAS AND ELECTRIC COMPANY
FOOTNOTES TO HYDRO GENERATING PLANTS - PAGES 406-407
Year ended December 31, 2019

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

Average Number of Employees on pages 406 and 407 line 11 left blank due to remote operation and remote area headquarters. Refer to the table below for further details on operations and maintenance staffing for each plant. Many of these plants are attended by roving operators as well additional support staff.

PLANT NAME:	REMOTELY OPERATED (Y/N):	REGIONAL OPERATING CENTER:	NUMER OF OPERATORS:	OPERATIONS HEADQUARTERS:	NUMBER OF OPERATORS:	MAINTENANCE HEADQUARTERS:	NUMBER OF SUPPORT STAFF:
PIT NO. 1	Y	None	None	Pit 3 Switching Center	12	Burney Service	45
PIT NO. 3	N					Center	
PIT NO. 4	Y						
HAT CREEK NO. 1	Y						
HAT CREEK NO. 2	Y						
PIT NO. 5	N			Pit 5 Switching Center	12		
PIT NO. 6	Y						
PIT NO. 7	Y						
JAMES B. BLACK	Y						
COLEMAN	Y			Manton Service Center	2	Manton Service Center	13
DE SABLA	N			Camp 1	4	Potter Valley PH	1
				Potter Valley PH	2		
BUTT VALLEY	Y			Rock Creek Switching Center	18	Rogers Flat	50
CARIBOU NO. 1	Y					Service Center	
CARIBOU NO. 2	Y						
BELDEN	Y						
ROCK CREEK	Y						
BUCKS CREEK	Y						
CRESTA	Y						
POE	Y						
DRUM NO. 1	N			Drum Switching Center	10	Auburn	19
DRUM NO. 2	Y					Service Center	
DUTCH FLAT	Y						
NARROWS	Y			Wise Switching Center	10	Wise PH	3
HALSEY	Y					Alta Service Center	10
WISE NO. 1	N						
NEWCASTLE	Y						
SALT SPRINGS	Y			Tiger Creek Switching Center	10	Tiger Creek	20
TIGER CREEK	Y					Service Center	
WEST POINT	Y						
ELECTRA	Y						
STANISLAUS	Y			Angels Camp Service Center	3	Angels Camp Service Center	11
						Sonora Service Center	7
HAAS	Y	Fresno	5	Balch Camp	4	Auberry	33
BALCH NO. 1	Y	Operating Center				Service Center	
BALCH NO. 2	Y						
KINGS RIVER	Y						
KERCKHOFF NO. 1	Y			Auberry	3		
KERCKHOFF NO. 2	Y			Service Center			
A. G. WISHON	N						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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
6	Plant Hours Connect to Load While Generating	2
7	Net Plant Capability (in megawatts)	1,212
8	Average Number of Employees	20
9	Generation, Exclusive of Plant Use - Kwh	744,443,735
10	Energy Used for Pumping	1,042,986,575
11	Net Output for Load (line 9 - line 10) - Kwh	-298,542,840
12	Cost of Plant	
13	Land and Land Rights	750,967
14	Structures and Improvements	186,884,679
15	Reservoirs, Dams, and Waterways	451,441,494
16	Water Wheels, Turbines, and Generators	273,951,053
17	Accessory Electric Equipment	67,360,259
18	Miscellaneous Powerplant Equipment	36,873,525
19	Roads, Railroads, and Bridges	8,780,989
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	1,026,042,966
22	Cost per KW of installed cap (line 21 / 4)	974.3998
23	Production Expenses	
24	Operation Supervision and Engineering	15,098
25	Water for Power	69,297
26	Pumped Storage Expenses	1,545
27	Electric Expenses	1,638,811
28	Misc Pumped Storage Power generation Expenses	1,880,460
29	Rents	45,524
30	Maintenance Supervision and Engineering	1,537
31	Maintenance of Structures	605,890
32	Maintenance of Reservoirs, Dams, and Waterways	373,351
33	Maintenance of Electric Plant	3,667,961
34	Maintenance of Misc Pumped Storage Plant	1,563,188
35	Production Exp Before Pumping Exp (24 thru 34)	9,862,662
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	9,862,662
38	Expenses per KWh (line 37 / 9)	0.0132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

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

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

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDROELECTRIC GENERATING PLANTS:					
2	Alta FERC No.2310	1902	1.00	1.0	3,395,006	13,831,281
3	Centerville FERC No.803	1904	6.40	6.4		1,743,779
4	Chili Bar FERC No.2155	1965	7.02	7.0	35,108,756	18,074,719
5	Coal Canyon	1907	0.18	0.2	35,875	7,029,005
6	Cow Creek FERC No.606	1907	1.44	1.8	4,462,672	3,405,236
7	Crane Valley FERC No.1354	1919	0.99	0.9	960,379	22,656,123
8	Deer Creek FERC No.2310	1908	5.50	5.7	16,180,996	87,420,189
9	Hamilton Branch	1921	5.39	4.8	-122,165	8,590,155
10	Inskip FERC No.1121	1979	7.65	8.0		22,345,689
11	Kern Canyon FERC No. 178	1921	9.54	11.5		12,782,686
12	Kilarc FERC No.606	1904	3.00	1.6	2,213,606	4,322,949
13	Lime Saddle	1906	2.00	2.0		17,647,506
14	Merced Falls FERC No.2467	1930				
15	Oak Flat FERC No.2105	1985	1.40	1.3	4,295,327	8,720,673
16	Phoenix FERC No.1061	1940	1.60	2.0	6,424,471	15,532,702
17	Potter Valley FERC No.77	1910	9.46	9.2	18,833,715	48,830,863
18	San Joaquin No. 1-A FERC No.1354	1919	0.42	0.4		35,368,891
19	San Joaquin No. 2 FERC No.1354	1917	2.88	3.2		32,581,072
20	San Joaquin No. 3 FERC No.1354	1923	4.00	4.2		26,940,374
21	South FERC No.1121	1979	6.75	7.0	24,953,448	16,988,742
22	Spaulding No. 1 FERC No.2310	1928	7.04	7.0	6,643,134	42,947,879
23	Spaulding No. 2 FERC No.2310	1928	3.70	4.4	8,089,423	20,472,680
24	Spaulding No. 3 FERC No.2310	1929	6.61	5.8	27,514,252	18,180,261
25	Spring Gap FERC No.2130	1921	6.00	7.0	34,667,760	12,122,541
26	Toadtown FERC No.803	1986	1.80	1.5	4,322,131	7,276,544
27	Tule FERC No.1333	1914	4.50	6.4		15,025,539
28	Volta No.1 FERC No.1121	1980	8.55	9.0	48,307,038	17,570,922
29	Volta No.2 FERC No.1121	1981	0.95	0.9	4,534,515	3,104,383
30	Wise II FERC No.2310	1986	2.87	3.2	-32,779	13,225,887
31	Miscellaneous Minor					4,303,384
32						
33	Photo Voltaic Generating Plants:					
34	AT&T PARK SOLAR ARRAYS	2007	0.11	0.1	87,777	1,990,928
35	SF SERVICE CENTER SOLAR ARRAY 1 & 2	2007	0.18	0.2	61,799	72,959
36	Vaca Dixon Solar Station	2009	2.00	2.0	3,073,911	10,881,965
37	Five Points - Schindler Solar Station #1	2011	15.00	15.0	26,209,055	54,818,128
38	Westside - Schindler Solar Station #2	2011	15.00	15.0	27,663,216	48,312,358
39	Stroud Solar Station	2011	20.00	20.0	33,508,633	62,321,706
40	Cantua Solar Station	2012	20.00	20.0	40,364,941	56,349,026
41	Giffen Solar Station	2012	10.00	10.0	17,464,494	31,412,761
42	Huron Solar Station	2012	20.00	20.0	39,941,301	61,433,310
43	Gates Solar Station	2013	20.00	20.0	33,234,616	65,649,055
44	West Gates Solar Station	2013	10.00	10.0	18,063,327	35,775,278
45	Guernsey Solar Station	2013	20.00	20.0	43,082,968	77,128,541
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	9,080,200	8,504,503
3	California State University East Bay	2011	1.40	1.4	4,677,855	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
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	03/25/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
13,634,782	277,785		402,853	Water		2
2,728,729	426,974		160,769	Water		3
2,574,852	327,785		422,205	Water		4
	22,211		40,434	Water		5
2,210,376	316,925		388,717	Water		6
23,493,026	194,325		426,631	Water		7
15,931,123	344,121		828,775	Water		8
1,593,470	314,216		118,277	Water		9
2,666,058	497,176		165,713	Water		10
1,339,973	210,718		47,782	Water		11
1,444,015	334,912		251,551	Water		12
6,252,102	635,973		419,653	Water		13
			2,141	Water		14
6,273,844	252,120		121,231	Water		15
9,612,860	255,198		416,118	Water		16
5,196,251	3,099,603		832,451	Water		17
76,547,157	103,485		146,572	Water		18
11,511,713	314,665		48,237	Water		19
6,881,438	388,753		64,978	Water		20
2,517,413	613,762		263,631	Water		21
5,955,135	390,888		521,470	Water		22
5,005,809	324,406		449,924	Water		23
2,277,594	314,296		422,147	Water		24
2,028,568	298,486		661,680	Water		25
4,048,526	395,539		167,147	Water		26
3,339,189	119,479		95,843	Water		27
2,052,974	630,113		482,115	Water		28
3,268,501	657,971		132,741	Water		29
4,588,903	492,031		313,423	Water		30
				Water		31
						32
						33
17,936,287			34,632	Solar		34
405,327				Solar		35
5,440,983	37,208		48,577	Solar		36
3,654,542	57,725		120,321	Solar		37
3,220,824	65,717		62,561	Solar		38
3,116,085	74,058		83,403	Solar		39
2,817,451	46,376		68,694	Solar		40
3,141,276	38,976		72,087	Solar		41
3,059,863	61,975		79,830	Solar		42
3,282,453	49,400		72,080	Solar		43
7,712,854	40,211		41,119	Solar		44
1,788,764	39,957		86,446	Solar		45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
5,315,314	243,968		427,343	Natural Gas		2
4,701,886	230,472		300,150	Natural Gas		3
						4
						5
						6
				Diesel		7
				Diesel		8
				Diesel		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

Schedule Page: 410 Line No.: 5 Column: a

No federal license required. This power plant was retired on April 1, 2013.

Schedule Page: 410 Line No.: 9 Column: a

No federal license required.

Schedule Page: 410 Line No.: 13 Column: a

No federal license required.

Schedule Page: 410 Line No.: 14 Column: a

This hydroelectric plant was sold to Merced Irrigation District on April 16, 2017.

Schedule Page: 410 Line No.: 31 Column: a

No federal license required.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	DIABLO UNIT #1		500.00	500.00	T	0.54		1
2	DIABLO UNIT #2		500.00	500.00	T	0.57		1
3	DIABLO	GATES #1	500.00	500.00	T	79.23		1
4	DIABLO	MIDWAY #2	500.00	500.00	T	84.07		1
5	DIABLO	MIDWAY #3	500.00	500.00	T	84.67		1
6	GATES	MIDWAY	500.00	500.00	SSP T	63.78		1
7	LOS BANOS	GATES #1	500.00	500.00	T	80.85		1
8	LOS BANOS	MIDWAY #2	500.00	500.00	T	144.82		1
9	MALIN	ROUND MTN #2	500.00	500.00	OTHERS T	46.90		1
10	MIDWAY	WHIRLWIND	500.00	500.00	T	52.77		1
11	MOSS LANDING	LOS BANOS	500.00	500.00	SSP T	51.33		1
12	MOSS LANDING	METCALF	500.00	500.00	T	34.98		1
13	ROUND MTN	TABLE MTN #1	500.00	500.00	SSP T	89.03		1
14	ROUND MTN	TABLE MTN #2	500.00	500.00	SSP T	89.02		1
15	TABLE MTN	TESLA	500.00	500.00	OTHERS T	134.99		1
16	TABLE MTN	VACA	500.00	500.00	T	83.30		1
17	TESLA	LOS BANOS #1	500.00	500.00	T	57.14		1
18	TESLA	METCALF	500.00	500.00	T	35.31		1
19	TESLA	TRACY	500.00	500.00	SSP T	1.13		1
20	TRACY	LOS BANOS	500.00	500.00	SSP T	56.23		1
21	VACA	TESLA	500.00	500.00	T	57.00		1
22	LAS AGUILAS SW STA	PANOCHE #2	230.00	230.00	SSP	17.44		1
23	LAS AGUILAS SW STA	PANOCHE #1	230.00	230.00	SSP T	17.44		1
24	BORDEN	GREGG #1	230.00	230.00	SSP T	6.22		1
25	CAMANCHE PUMPING		230.00	230.00	SSP T	0.45		1
26	BIRDS LANDING SW STA	SHILOH	230.00	230.00	SSP	0.11		1
27	PANOCHE	PANOCHE ENERGY	230.00	230.00	SSP	0.09		1
28	GATES	MUSTANG SW STA #1	230.00	230.00	SSP T	13.17		1
29	GATES	MUSTANG SW STA #2	230.00	230.00	SSP T	13.18		1
30	FULTON	LAKEVILLE-IGNACIO	230.00	230.00		15.84		1
31	NEWARK	LOS ESTEROS	230.00	230.00	SSP	5.65		1
32	LAKEVILLE	IGNACIO #2	230.00	230.00	T	14.53		1
33	DELEVAN	VACA #2	230.00	230.00	T	71.07		1
34	SHILOH II	BIRDS LANDING SW STA	230.00	230.00	SSP	3.56		1
35	ARCO	MIDWAY	230.00	230.00	SSP T	43.36		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	ATLANTIC	GOLD HILL	230.00	230.00	T	11.11		1
2	BAHIA	MORAGA	230.00	230.00	T	26.92		1
3	BALCH	MCCALL	230.00	230.00		39.76		1
4	BELLOTA	COTTLE	230.00	230.00	T	19.87		1
5	BELLOTA	TESLA #2	230.00	230.00	SSP	37.94		1
6	BELLOTA	WARNERVILLE	230.00	230.00	SSP	22.47		1
7	DELEVAN	CORTINA	230.00	230.00	T	17.97		1
8	BELLOTA	WEBER	230.00	230.00	SSP T	14.26		1
9	BORDEN	GREGG #2	230.00	230.00	SSP	6.21		1
10	BRENTWOOD	KELSO	230.00	230.00	SSP T	16.41		1
11	BRIGHTON	BELLOTA	230.00	230.00	T	42.51		1
12	BUCKS CREEK	ROCK CREEK-CRESTA	230.00	230.00	SSP OTHERS	9.39		1
13	CARIBOU	TABLE MTN	230.00	230.00	SSP OTHERS	54.34		1
14	BELDEN TAP		230.00	230.00	SSP	0.02		1
15	CASTRO VALLEY	NEWARK	230.00	230.00	T	22.71		1
16	COBURN	LAS AGUILAS SW STA	230.00	230.00	SSP T	63.97		1
17	CONTRA COSTA PP	CONTRA COSTA SUB	230.00	230.00	T	1.89		1
18	CONTRA COSTA	BRENTWOOD	230.00	230.00	SSP T	10.06		1
19	CONTRA COSTA	DELTA SWITCHYARD	230.00	230.00	T	18.46		1
20	WINDMASTER TAP		230.00	230.00	SSP	0.11		1
21	NORTH DUBLIN	CAYETANO	230.00	230.00	T	3.02		1
22	NORTH DUBLIN	VINEYARD	230.00	230.00	T	12.46		1
23	CONTRA COSTA	LAS POSITAS	230.00	230.00	SSP T	23.83		1
24	US WINDPOWER #3 TAP		230.00	230.00	SSP	0.06		1
25	COTTLE	MELONES	230.00	230.00	SSP T	25.94		1
26	TES TAP		230.00	230.00	SSP T	3.28		1
27	CONTRA COSTA	LONE TREE	230.00	230.00		5.62		1
28	VINEYARD	NEWARK	230.00	230.00	T	14.36		1
29	CORTINA	VACA	230.00	230.00	T	53.29		1
30	COTTONWOOD	DELEVAN #1	230.00	230.00	SSP T	71.55		1
31	COTTONWOOD	GLENN	230.00	230.00	T	48.33		1
32	COTTONWOOD	LOGAN CREEK	230.00	230.00	T	59.28		1
33	COTTONWOOD	DELEVAN #2	230.00	230.00	T	71.54		1
34	CRESTA	RIO OSO	230.00	230.00	SSP T	64.79		1
35	DELTA SWITCHING YARD	TESLA	230.00	230.00	T	7.70		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	DIABLO PP STANDBY		230.00	230.00	T	0.46		1
2	DIABLO	MESA	230.00	230.00	T	40.34		1
3	DOS AMIGOS PUMPING	PANOCHE	230.00	230.00	SSP T	23.68		1
4	NEWARK E	F BUS TIE	230.00	230.00		0.22		1
5	EASTSHORE	SAN MATEO	230.00	230.00	SSP	12.43		1
6	EIGHT MILE ROAD	TESLA	230.00	230.00	SSP OTHERS	26.64		1
7	ELECTRA	BELLOTA	230.00	230.00	SSP T	29.23		1
8	FULTON	IGNACIO #1	230.00	230.00	SSP T	40.73		1
9	GATES	ARCO	230.00	230.00	T	35.18		1
10	MUSTANG SW STA	GREGG	230.00	230.00	SSP T	45.47		1
11	MUSTANG SW STA	MCCALL	230.00	230.00	SSP T	42.11		1
12	GATES	PANOCHE #1	230.00	230.00	SSP T	43.79		1
13	GATES	PANOCHE #2	230.00	230.00	SSP T	43.80		1
14	GEYSERS #12	FULTON	230.00	230.00	SSP OTHERS	24.09		1
15	GEYSERS #16 TAP		230.00	230.00	T	1.29		1
16	GEYSERS #17	FULTON	230.00	230.00	SSP T	26.14		1
17	BOTTLE ROCK TAP D.W.R.		230.00	230.00	T	1.07		1
18	GEYSERS #9	LAKEVILLE	230.00	230.00	SSP	41.19		1
19	GEYSERS #9	LAKEVILLE	230.00	230.00	SSP	0.51		1
20	GEYSERS #13 TAP		230.00	230.00	T	2.06		1
21	SANTA FE GEOTHERMAL		230.00	230.00	SSP T	1.04		1
22	GEYSERS #20 TAP		230.00	230.00		0.03		1
23	GEYSERS #18 TAP		230.00	230.00	SSP T	0.75		1
24	DELEVAN	VACA #3	230.00	230.00	T	71.08		1
25	GOLD HILL	EIGHT MILE ROAD	230.00	230.00	SSP T	48.80		1
26	GOLD HILL	LODI STIG	230.00	230.00	T	46.67		1
27	GREGG	ASHLAN	230.00	230.00	SSP T	7.00		1
28	GREGG	HERNDON #1	230.00	230.00	T	0.60		1
29	GREGG	HERNDON #2	230.00	230.00	T	0.63		1
30	HAAS	MCCALL	230.00	230.00	SSP T	44.21		1
31	HELM	MCCALL	230.00	230.00	T	30.84		1
32	HELMS	GREGG #1	230.00	230.00	T	60.67		1
33	HELMS	GREGG #2	230.00	230.00	T	60.68		1
34	HERNDON	ASHLAN	230.00	230.00	SSP T	6.39		1
35	GATES	MIDWAY	230.00	230.00	SSP T	63.86		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	HERNDON	KEARNEY	230.00	230.00	T	10.81		1
2	HICKS	METCALF	230.00	230.00	SSP T	9.07		1
3	IGNACIO	SOBRANTE	230.00	230.00	SSP T	42.49		1
4	KELSO	TESLA	230.00	230.00	SSP T	7.95		1
5	RALPH TAP		230.00	230.00	SSP	0.06		1
6	LAKEVILLE	IGNACIO #1	230.00	230.00	SSP T	15.49		1
7	FULTON	LAKEVILLE	230.00	230.00	SSP T	25.51		1
8	LAKEVILLE	SOBRANTE #2	230.00	230.00	SSP	47.89		1
9	LAKEVILLE	TULUCAY	230.00	230.00	SSP OTHERS	17.22		1
10	LAS POSITAS	NEWARK	230.00	230.00	SSP T	20.93		1
11	LOCKEFORD	BELLOTA	230.00	230.00	T	12.32		1
12	PANOCHE	TRANQUILLITY SW STA #1	230.00	230.00	SSP T	12.14		1
13	LODI STIG	EIGHT MILE ROAD	230.00	230.00	SSP T	2.18		1
14	EIGHT MILE ROAD	STAGG	230.00	230.00	SSP T	7.20		1
15	DELEVAN	VACA #1	230.00	230.00	T	71.04		1
16	LOS BANOS	DOS AMIGOS	230.00	230.00	T	14.31		1
17	LOS BANOS	PANOCHE #1	230.00	230.00	OTHERS T	37.18		1
18	LOS BANOS	PANOCHE #2	230.00	230.00	SSP T	37.13		1
19	LOS BANOS	SAN LUIS PUMPS #1	230.00	230.00	T	3.43		1
20	LOS BANOS	SAN LUIS PUMPS #2	230.00	230.00	T	3.43		1
21	QUINTO SW STA	WESTLEY	230.00	230.00	T	57.55		1
22	LOS BANOS	QUINTO SW STA	230.00	230.00	T	12.06		1
23	MELONES	WILSON	230.00	230.00	SSP T	61.61		1
24	MONTA VISTA	COYOTE SW STA	230.00	230.00	T	27.83		1
25	METCALF	MONTA VISTA #3	230.00	230.00		28.59		1
26	COYOTE SW STA	METCALF	230.00	230.00	T	0.88		1
27	METCALF	MOSS LANDING #1	230.00	230.00	SSP T	35.76		1
28	METCALF	MOSS LANDING #2	230.00	230.00	SSP	35.76		1
29	MIDDLE FORK	GOLD HILL	230.00	230.00	SSP OTHERS	44.08		1
30	MIDWAY	KERN #1	230.00	230.00	SSP T	41.75		1
31	BAKERSFIELD #1 TAP		230.00	230.00	SSP T	6.67		1
32	STOCKDALE #1 TAP		230.00	230.00	SSP T	6.25		1
33	MIDWAY	KERN #3	230.00	230.00	T	20.88		1
34	STOCKDALE #2 TAP		230.00	230.00	T	6.16		1
35	MIDWAY	KERN #4	230.00	230.00	SSP T	20.84		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	BAKERSFIELD #2 TAP		230.00	230.00	T	7.01		1
2	MIDWAY	WHEELER RIDGE #1	230.00	230.00	T	52.68		1
3	BUENA VISTA PUMPING		230.00	230.00	T	1.18		1
4	WHEELER RIDGE PUMPING		230.00	230.00	T	0.25		1
5	WIND GAP PUMPING PLANT		230.00	230.00	T	1.64		1
6	MIDWAY	SUNSET	230.00	230.00	T	0.57		1
7	MIDWAY	WHEELER RIDGE #2	230.00	230.00		52.65		1
8	BUENA VISTA PUMPING		230.00	230.00	T	1.21		1
9	WHEELER RIDGE PUMPING		230.00	230.00		0.23		1
10	WIND GAP PUMPING PLANT		230.00	230.00		1.62		1
11	MONTA VISTA	HICKS	230.00	230.00	SSP T	13.27		1
12	SOLAR SW STA	CALIENTE SW STA #1	230.00	230.00	T	8.22		1
13	CALIENTE SW STA	MIDWAY #1	230.00	230.00	SSP T	27.17		1
14	MONTA VISTA	JEFFERSON #1	230.00	230.00	SSP T	19.72		1
15	SOLAR SW STA	CALIENTE SW STA #2	230.00	230.00	T	8.22		1
16	CALIENTE SW STA	MIDWAY #2	230.00	230.00	T	27.16		1
17	MONTA VISTA	JEFFERSON #2	230.00	230.00	SSP	19.73		1
18	MONTA VISTA	SARATOGA	230.00	230.00	SSP T	5.49		1
19	MORAGA	CASTRO VALLEY	230.00	230.00	T	14.92		1
20	MORRO BAY	DIABLO	230.00	230.00		15.78		1
21	MORRO BAY	CALIFORNIA FLATS SW STA	230.00	230.00	SSP OTHERS	46.19		1
22	CALIFORNIA FLATS SW STA	GATES	230.00	230.00	SSP OTHERS	22.57		1
23	MORRO BAY	MESA	230.00	230.00	T	35.27		1
24	MORRO BAY	SOLAR SW STA #1	230.00	230.00	SSP T	45.55		1
25	MORRO BAY	SOLAR SW STA #2	230.00	230.00	SSP T	45.56		1
26	MOSS LANDING	COBURN	230.00	230.00	SSP SWP T	64.03		1
27	MOSS LANDING	LAS AGUILAS SW STA	230.00	230.00	SSP	51.89		1
28	RAVENSWOOD	SAN MATEO #2	230.00	230.00	SSP	11.88		1
29	LOS ESTEROS	METCALF	230.00	230.00	SSP T	63.25		1
30	TESLA	NEWARK #2	230.00	230.00	SSP SWP T	40.88		1
31	PALERMO	COLGATE	230.00	230.00	SSP T	29.60		1
32	TRANQUILLITY SW STA	HELM	230.00	230.00	SSP T	12.68		1
33	TRANQUILLITY SW STA	KEARNEY	230.00	230.00	SSP T	36.90		1
34	PIT #1	COTTONWOOD	230.00	230.00	SSP OTHERS	59.75		1
35	BURNEY FOREST		230.00	230.00	T	0.04		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SPI (BURNEY) TAP		230.00	230.00	T	0.05		1
2	PIT #3	PIT #1	230.00	230.00	SSP OTHERS	22.69		1
3	CARBERRY SW STA	ROUND MTN	230.00	230.00	SSP OTHERS	12.61		1
4	PIT #5	ROUND MTN #1	230.00	230.00	OTHERS T	13.12		1
5	COVE ROAD TAP		230.00	230.00	SSP	0.11		1
6	PIT #5	ROUND MTN #2	230.00	230.00	SSP OTHERS	13.11		1
7	BLACK TAP		230.00	230.00	T	0.51		1
8	PIT #4 TAP		230.00	230.00	SSP T	7.03		1
9	PIT #6 JCT	ROUND MTN	230.00	230.00	SSP OTHERS	8.15		1
10	PIT #6 TAP		230.00	230.00	OTHERS T	3.43		1
11	PIT #7 TAP		230.00	230.00	OTHERS T	3.59		1
12	PIT #3	CARBERRY SW STA	230.00	230.00	SSP T	10.91		1
13	ROSSMOOR #1 TAP		230.00	230.00	T	0.69		1
14	CONTRA COSTA	MORAGA #1	230.00	230.00	SSP T	26.76		1
15	CONTRA COSTA	MORAGA #2	230.00	230.00	SSP T	26.84		1
16	ROSSMOOR #2 TAP		230.00	230.00	T	0.66		1
17	PITTSBURG	EASTSHORE	230.00	230.00	SSP SWP T	34.92		1
18	PITTSBURG	SAN MATEO	230.00	230.00	SSP OTHERS	47.40		1
19	PITTSBURG	TASSAJARA	230.00	230.00	SSP	17.36		1
20	PANOCHE	TRANQUILLITY SW STA #2	230.00	230.00	SSP T	12.14		1
21	PITTSBURG	SAN RAMON	230.00	230.00	SSP SWP T	21.66		1
22	PITTSBURG	TESORO	230.00	230.00		11.27		1
23	PITTSBURG	TESLA #1	230.00	230.00	SSP T	31.35		1
24	PITTSBURG	TESLA #2	230.00	230.00	SSP SWP T	31.32		1
25	PITTSBURG	TIDEWATER	230.00	230.00	T	11.27		1
26	POE	RIO OSO	230.00	230.00	SSP OTHERS	56.09		1
27	RANCHO SECO	BELLOTA #1	230.00	230.00	T	27.39		1
28	RANCHO SECO	BELLOTA #2	230.00	230.00		27.36		1
29	RAVENSWOOD	SAN MATEO #1	230.00	230.00	SSP T	11.89		1
30	RIO OSO	ATLANTIC	230.00	230.00	SSP T	17.68		1
31	RIO OSO	BRIGHTON	230.00	230.00	T	27.17		1
32	RIO OSO	GOLD HILL	230.00	230.00	T	28.63		1
33	RIO OSO	LOCKEFORD	230.00	230.00	T	65.13		1
34	ROCK CREEK	POE	230.00	230.00	SSP OTHERS	26.98		1
35	ROUND MTN	COTTONWOOD #2	230.00	230.00	OTHERS T	33.67		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	ROUND MTN	COTTONWOOD #3	230.00	230.00	SSP OTHERS	33.36		1
2	SAN RAMON	MORAGA	230.00	230.00	SSP SWP T	22.24		1
3	TESORO	SOBRANTE	230.00	230.00		12.32		1
4	STAGG	TESLA	230.00	230.00		23.64		1
5	TABLE MTN	PALERMO	230.00	230.00	OTHERS T	14.57		1
6	TABLE MTN	RIO OSO	230.00	230.00		50.18		1
7	JEFFERSON	MARTIN	230.00	230.00	SSP	3.31		1
8	TESLA	NEWARK #1	230.00	230.00	T	28.19		1
9	TESLA	RAVENSWOOD	230.00	230.00	SSP	37.14		1
10	TESLA	TRACY #1	230.00	230.00	T	5.68		1
11	TESLA	TRACY #2	230.00	230.00		5.68		1
12	TESLA	WESTLEY	230.00	230.00	T	45.06		1
13	TIDEWATER	SOBRANTE	230.00	230.00	SSP T	12.32		1
14	TIGER CREEK	ELECTRA	230.00	230.00	OTHERS T	13.65		1
15	TIGER CREEK	VALLEY SPRINGS	230.00	230.00	OTHERS T	24.22		1
16	TULUCAY	VACA	230.00	230.00	SSP T	23.63		1
17	VACA	BAHIA	230.00	230.00	SSP T	33.90		1
18	LAMBIE SW STA	BIRDS LANDING SW STA	230.00	230.00	T	7.04		1
19	VACA	PEABODY	230.00	230.00	SSP T	9.69		1
20	BIRDS LANDING SW STA	CONTRA COSTA PP	230.00	230.00	SSP T	10.20		1
21	VACA	LAKEVILLE #1	230.00	230.00	SSP T	40.93		1
22	VACA	LAMBIE SW STA	230.00	230.00	T	13.95		1
23	VACA	PARKWAY	230.00	230.00	SSP T	27.76		1
24	VALLEY SPRINGS	BELLOTA	230.00	230.00	T	20.67		1
25	WARNERVILLE	WILSON	230.00	230.00		38.40		1
26	WEBER	TESLA	230.00	230.00	T	23.71		1
27	WILSON	BORDEN #1	230.00	230.00	SSP T	35.31		1
28	COLGATE	RIO OSO	230.00	230.00	T	40.89		1
29	MALACHA TAP		230.00	230.00	T	0.12		1
30	TASSAJARA	NEWARK	230.00	230.00	SSP OTHERS	31.80		1
31	SAN RAMON RESEARCH		230.00	230.00	SSP T	3.27		1
32	PARKWAY	MORAGA	230.00	230.00	T	23.64		1
33	SARATOGA	VASONA	230.00	230.00	SSP T	3.41		1
34	VASONA	METCALF	230.00	230.00	SSP T	13.29		1
35	MORRO BAY	TEMPLETON	230.00	230.00	SSP T	16.43		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	TEMPLETON	GATES	230.00	230.00	T	52.18		1
2	VACA DIXON	MORAGA #1	230.00	230.00	T	3.08		1
3	NEWARK	RAVENSWOOD	230.00	230.00	T	8.91		1
4	RUSSELL CITY ENERGY	EASTSHORE #1	230.00	230.00	SSP	1.19		1
5	RUSSELL CITY ENERGY	EASTSHORE #2	230.00	230.00	SSP	1.20		1
6	LONE TREE	CAYETANO	230.00	230.00	SSP T	15.40		1
7	BIRDS LANDING SW STA	CONTRA COSTA SUB	230.00	230.00	SSP T	9.46		1
8	PEABODY	BIRDS LANDING SW STA	230.00	230.00	SSP SWP T	19.85		1
9	LOGAN CREEK	DELEVAN	230.00	230.00	T	12.35		1
10	BIRDS LANDING SW STA	RUSSELL	230.00	230.00	SSP	0.11		1
11	GLENN	DELEVAN	230.00	230.00	SSP T	37.42		1
12	MONTEZUMA SW STA	BIRDS LANDING SW STA	230.00	230.00	OTHERS SSP	0.54		1
13	WILSON	BORDEN #2	230.00	230.00	SSP T	35.37		1
14	ZA	1	230.00	230.00	N/A	3.41		1
15	NORTH DUBLIN	CAYETANO	230.00	230.00	N/A	2.81		1
16	JEFFERSON	MARTIN	230.00	230.00	N/A	24.41		1
17	LONE TREE	CAYETANO	230.00	230.00	N/A	2.30		1
18	NEWARK	LOS ESTEROS	230.00	230.00	N/A	2.75		1
19	LOS ESTEROS	METCALF	230.00	230.00	N/A	2.73		1
20	VINEYARD	NEWARK	230.00	230.00	N/A	5.94		1
21	NORTH DUBLIN	VINEYARD	230.00	230.00	N/A	11.07		1
22	SAN MATEO	MARTIN	230.00	230.00	N/A	13.00		1
23	H	Z #1	230.00	230.00	N/A	6.92		1
24	H	Z #2	230.00	230.00	N/A	6.96		1
25	FIGARDEN #1 TAP		230.00	230.00	N/A	0.85		1
26	FULTON	LAKEVILLE	230.00	230.00	N/A	1.19		1
27	GEYSERS #9	LAKEVILLE	230.00	230.00	N/A	1.24		1
28	FIGARDEN #2 TAP		230.00	230.00	N/A	0.83		1
29	STELLING	MONTA VISTA	115.00	115.00	SSP T	1.61		1
30	WHISMAN	MONTA VISTA	115.00	115.00	T	5.97		1
31	ATWATER	EL CAPITAN	115.00	115.00	SSP T	7.31		1
32	ATWATER	LIVINGSTON-MERCED	115.00	115.00	SWP SSP	24.26		1
33	GALLO	LIVINGSTON	115.00	115.00	SWP SSP	4.20		1
34	ATWATER	CRESSEY	115.00	115.00	SWP SSP	5.91		1
35	GALLO	CRESSEY	115.00	115.00	SWP SSP	14.43		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	BAIR	BELMONT	115.00	115.00	SSP	3.64		1
2	BALCH	SANGER	115.00	115.00	SSP OTHERS	35.62		1
3	PANOCHE	CAL PEAK-STARWOOD	115.00	115.00	SWP	0.10		1
4	BARTON	AIRWAYS-SANGER	115.00	115.00	SSP OTHERS	11.65		1
5	BELLOTA	RIVERBANK-MELONES SW	115.00	115.00	SSP OTHERS	44.65		1
6	TULLOCH TAP		115.00	115.00	OTHERS SWP	0.31		1
7	MI	WUK-CURTIS	115.00	115.00	OTHERS SSP	8.40		1
8	BIG BEND	CLAYTON #1	115.00		SWP T	0.02		1
9	BOGUE	RIO OSO	115.00	115.00	SSP T	21.24		1
10	GREENLEAF #1 TAP		115.00	115.00	SWP SSP	4.84		1
11	BRIDGEVILLE	COTTONWOOD	115.00	115.00	SSP OTHERS	86.06		1
12	BRIGHTON	CLAYTON #1	115.00	115.00	T	6.72		1
13	BRIGHTON	CLAYTON #2	115.00	115.00		6.72		1
14	BRIGHTON	DAVIS	115.00	115.00	SSP OTHERS	42.73		1
15	BRIGHTON	DAVIS	115.00	115.00	SSP OTHERS	17.36		1
16	BARKER SLOUGH TAP		115.00	115.00	SWP	1.62		1
17	BRIGHTON	GRAND ISLAND #1	115.00	115.00	SSP OTHERS	24.99		1
18	BRIGHTON	GRAND ISLAND #1	115.00	115.00	SSP OTHERS	0.14		1
19	BRIGHTON	GRAND ISLAND #2	115.00	115.00	SWP SSP	25.04		1
20	BRIGHTON	GRAND ISLAND #2	115.00	115.00	SWP SSP	0.14		1
21	BRITTON	MONTA VISTA	115.00	115.00	SSP	7.17		1
22	BUTTE VALLEY	CARIBOU	115.00	115.00	SSP OTHERS	7.44		1
23	BUTTE	SYCAMORE CREEK	115.00	115.00	SWP SSP	18.17		1
24	CABRILLO	SANTA YNEZ SW STA	115.00	115.00	SWP SSP	14.59		1
25	BUELLTON TAP		115.00	115.00	SWP	1.75		1
26	CALLENDER SW STA	MESA	115.00	115.00	SSP SWP T	13.77		1
27	CAMP EVERS	PAUL SWEET	115.00	115.00	OTHERS SSP	5.22		1
28	GRIZZLY TAP (SVP)		115.00	115.00	SWP T	0.16		1
29	CASCADE	COTTONWOOD	115.00	115.00	SSP OTHERS	19.46		1
30	CHOWCHILLA	KERCKHOFF	115.00	115.00	SSP OTHERS	42.52		1
31	SHARON PRISON TAP		115.00	115.00	SWP SSP	2.57		1
32	OAKHURST TAP		115.00	115.00	OTHERS SSP	18.16		1
33	CHRISTIE	SOBRANTE	115.00	115.00	T	7.84		1
34	TEICHERT TAP		115.00	115.00	OTHERS SSP	2.11		1
35	CLAYTON	MEADOW LANE	115.00	115.00	SWP SSP	7.06		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	CONTRA COSTA #1		115.00	115.00	SSP T	11.15		1
2	LEPRINO FOODS (TRACY)		115.00	115.00	SWP	0.02		1
3	WILSON	DAIRYLAND (12KV)	115.00	115.00	SWP	11.37		1
4	CONTRA COSTA #2		115.00	115.00		1.41		1
5	FIBREBOARD TAP		115.00	115.00	SSP SWP T	1.03		1
6	COOLEY LANDING	PALO ALTO	115.00	115.00	SWP SSP	2.72		1
7	CORCORAN	OLIVE SW STA	115.00	115.00	SSP T	36.83		1
8	QUEBEC TAP		115.00	115.00	SWP	4.35		1
9	RIO OSO	LINCOLN	115.00	115.00	OTHERS SSP	11.02		1
10	CORTINA	MENDOCINO #1	115.00	115.00	SWP T	60.95		1
11	LUCERNE #1 TAP		115.00	115.00	SWP	0.23		1
12	COTTONWOOD	PANORAMA	115.00	115.00	SWP SSP	2.95		1
13	CRAG VIEW	CASCADE	115.00	115.00	OTHERS T	21.61		1
14	DAIRYLAND	MENDOTA	115.00	115.00	SSP SWP T	28.69		1
15	DIVIDE	CABRILLO #2	115.00	115.00	OTHERS SSP	11.55		1
16	CITY #2 TAP		115.00	115.00	OTHERS SSP	1.37		1
17	MANVILLE TAP		115.00	115.00	OTHERS SSP	5.54		1
18	DIVIDE	CABRILLO #1	115.00	115.00	OTHERS SSP	14.60		1
19	SURF TAP		115.00	115.00	SWP SSP	11.38		1
20	CITY #1 TAP		115.00	115.00	SWP	0.07		1
21	DIXON LANDING	MCKEE	115.00	115.00	SWP SSP	8.30		1
22	DONNELLS	MI-WUK	115.00	115.00	SSP OTHERS	18.46		1
23	BEARDSLEY TAP		115.00	115.00	OTHERS T	2.20		1
24	SPRING GAP TAP		115.00	115.00	OTHERS T	1.64		1
25	SANDBAR TAP		115.00	115.00	OTHERS	0.09		1
26	FIBREBOARD STANDARD		115.00	115.00	OTHERS SWP	0.02		1
27	HIGGINS	BELL	115.00	115.00	SSP SWP T	18.77		1
28	DRUM	RIO OSO #1	115.00	115.00	SSP OTHERS	44.64		1
29	DUTCH FLAT #2 TAP		115.00	115.00	SSP OTHERS	0.43		1
30	BRUNSWICK #1 TAP		115.00	115.00	T	6.98		1
31	DRUM	RIO OSO #2	115.00	115.00	SSP OTHERS	44.65		1
32	BRUNSWICK #2 TAP		115.00	115.00	T	7.00		1
33	DRUM	SUMMIT #1	115.00	115.00	SSP OTHERS	27.36		1
34	DRUM	SUMMIT #2	115.00	115.00	SSP OTHERS	28.36		1
35	DUMBARTON	NEWARK	115.00	115.00	SSP T	7.14		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	EAGLE ROCK	CORTINA	115.00	115.00	OTHERS SSP	43.38		1
2	EAGLE ROCK	REDBUD	115.00	115.00	SSP OTHERS	23.31		1
3	LOWER LAKE	HOMESTAKE	115.00	115.00	SWP SSP	16.12		1
4	EAST GRAND	SAN MATEO	115.00	115.00	SSP OTHERS	7.89		1
5	EASTSHORE	DUMBARTON	115.00	115.00	SSP T	12.38		1
6	EASTSHORE	MT EDEN #1	115.00	115.00	T	1.04		1
7	EASTSHORE	MT EDEN #2	115.00	115.00		1.00		1
8	EL CAPITAN	WILSON	115.00	115.00	SSP T	8.12		1
9	EL PATIO	SAN JOSE A	115.00	115.00	SSP SWP T	7.08		1
10	EL DORADO	MISSOURI FLAT #1	115.00	115.00	SSP OTHERS	14.43		1
11	APPLE HILL #1 TAP		115.00	115.00	SWP SSP	1.42		1
12	EL DORADO	MISSOURI FLAT #2	115.00	115.00	SWP SSP	14.41		1
13	APPLE HILL #2 TAP		115.00	115.00	SWP SSP	1.43		1
14	SAN JOSE B	STONE-EVERGREEN	115.00	115.00	SWP SSP	8.56		1
15	NORTECH	NORTHERN RECEIVING	115.00	115.00	SSP	2.21		1
16	H	P #3	115.00	115.00	OTHERS T	0.17		1
17	EXCHEQUER	LE GRAND	115.00	115.00	OTHERS SSP	29.75		1
18	FELLOWS	MIDSUN	115.00	115.00	OTHERS SSP	4.73		1
19	FELLOWS	TAFT	115.00	115.00	SSP OTHERS	7.93		1
20	MIDSET TAP		115.00	115.00	SWP	0.72		1
21	FULTON JCT	VACA	115.00	115.00	SSP T	11.93		1
22	AMERIGAS TAP		115.00	115.00	SWP SSP	0.49		1
23	FULTON	PUEBLO	115.00	115.00	SSP OTHERS	59.90		1
24	RINCON #1 TAP		115.00	115.00	SSP T	0.57		1
25	MONTICELLO PH TAP		115.00	115.00	SWP SSP	0.62		1
26	SILVERADO	FULTON JCT	115.00	115.00	SWP T	26.16		1
27	RINCON #2 TAP		115.00	115.00	SSP	0.55		1
28	FULTON	SANTA ROSA #1	115.00	115.00	SSP SWP T	6.69		1
29	FULTON	SANTA ROSA #2	115.00	115.00	SWP SSP	6.29		1
30	GEYSERS #3	CLOVERDALE	115.00	115.00	SSP OTHERS	12.07		1
31	MISSION POWER TAP		115.00	115.00	SWP SSP	1.94		1
32	GEYSERS #3	EAGLE ROCK	115.00	115.00	OTHERS SSP	1.77		1
33	GEYSERS #5	GEYSERS #3	115.00	115.00	SWP	0.49		1
34	GEYSERS #7	EAGLE ROCK	115.00	115.00	SSP OTHERS	1.40		1
35	GOLD HILL	BELLOTA-LOCKEFORD	115.00	115.00	SSP T	87.28		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	CAMANCHE TAP		115.00	115.00	SWP SSP	6.71		1
2	GRANT	EASTSHORE #1	115.00	115.00	SSP T	4.33		1
3	GRANT	EASTSHORE #2	115.00	115.00	T	4.20		1
4	GREEN VALLEY	CAMP EVERS	115.00	115.00	SSP OTHERS	18.59		1
5	GREEN VALLEY	LLAGAS	115.00	115.00	SSP OTHERS	24.85		1
6	METCALF	SALINAS #1	115.00	115.00	T	1.94		1
7	GREEN VALLEY	PAUL SWEET	115.00	115.00	SSP OTHERS	16.03		1
8	METCALF	SALINAS #2 (12KV)	115.00	115.00		6.80		1
9	HENRIETTA	LEPRINO SW STA	115.00	115.00	SWP SSP	6.03		1
10	LEPRINO SW STA	HENRIETTA PV	115.00	115.00	SSP	0.06		1
11	KANSAS PV	LEPRINO SW STA	115.00	115.00	SSP	0.17		1
12	LEPRINO SW STA	GWF HANFORD SW STA	115.00	115.00	SWP SSP	12.38		1
13	LEPRINO FOODS	LEPRINO SW STA	115.00	115.00	SWP SSP	6.41		1
14	GILL RANCH TAP		115.00	115.00	SWP SSP	9.15		1
15	GWF	KINGSBURG	115.00	115.00	SWP SSP	21.62		1
16	PARAMOUNT FARMS TAP		115.00	115.00	SWP SSP	0.57		1
17	HERNDON	BARTON	115.00	115.00	SSP OTHERS	12.68		1
18	HERNDON	BULLARD #1	115.00	115.00	SSP T	11.43		1
19	HERNDON	BULLARD #2	115.00	115.00	SWP SSP	11.42		1
20	HERNDON	MANCHESTER	115.00	115.00	SWP SSP	9.27		1
21	HERNDON	WOODWARD	115.00	115.00	SSP SWP T	12.97		1
22	HUMBOLDT BAY	HUMBOLDT #1	115.00	115.00	SSP T	6.31		1
23	HUMBOLDT	BRIDGEVILLE	115.00	115.00	SSP OTHERS	30.28		1
24	HUMBOLDT	TRINITY	115.00	115.00	SSP OTHERS	68.57		1
25	IGNACIO	MARE ISLAND #1	115.00	115.00	SSP SWP T	39.48		1
26	CARQUINEZ #1 TAP		115.00	115.00	SSP T	0.51		1
27	SKAGGS ISLAND #1 TAP		115.00	115.00	T	0.59		1
28	JAMESON CANYON		115.00	115.00	SWP SSP	0.19		1
29	IGNACIO	MARE ISLAND #2	115.00	115.00	OTHERS T	43.08		1
30	CARQUINEZ #2 TAP		115.00	115.00	SSP	0.52		1
31	SKAGGS ISLAND #2 TAP		115.00	115.00	T	0.60		1
32	IGNACIO	SAN RAFAEL #1	115.00	115.00	SSP T	11.54		1
33	IGNACIO	SAN RAFAEL #3	115.00	115.00	SWP	8.65		1
34	JARVIS	CRYOGENICS	115.00	115.00	T	0.03		1
35	KERCKHOFF #1	KERCKHOFF #2	115.00	115.00	SSP T	1.58		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	KERCKHOFF	CLOVIS-SANGER #1	115.00	115.00	SSP OTHERS	37.05		1
2	WOODWARD	SHEPHERD	115.00	115.00	SWP SSP	4.84		1
3	KERCKHOFF	CLOVIS-SANGER #2	115.00	115.00	SSP SWP T	32.05		1
4	KERN OIL	DEXZEL	115.00	115.00	SWP	0.44		1
5	KERN OIL	WITCO	115.00	115.00	SSP T	4.20		1
6	DISCOVERY TAP		115.00	115.00	SWP	2.10		1
7	RIO BRAVO	KERN OIL	115.00	115.00	SWP SSP	7.28		1
8	OLIVE SW STA	SMYRNA	115.00	115.00	SSP T	22.09		1
9	KERN	KERN FRONT	115.00	115.00	OTHERS SSP	12.52		1
10	DOUBLE C (PSE) TAP		115.00	115.00	SWP	0.06		1
11	BADGER CREEK (PSE) TAP		115.00	115.00	SWP	1.07		1
12	SIERRA (PSE) TAP		115.00	115.00	SWP SSP	1.81		1
13	KERN	TEVIS-STOCKDALE-LAMON	115.00	115.00	SSP SWP T	21.52		1
14	LAMONT	GRIMMWAY MALAGA	115.00	115.00	SWP SSP	3.55		1
15	LERDO	KERN OIL-7TH STANDARD	115.00	115.00	SSP OTHERS	16.35		1
16	KERN	LIVE OAK	115.00	115.00	SSP SWP T	10.74		1
17	KERN	MAGUNDEN-WITCO	115.00	115.00	SSP OTHERS	19.58		1
18	KERNWATER TAP		115.00	115.00	SWP SSP	0.67		1
19	WITCO (REFINERY) TAP		115.00	115.00	SWP	0.03		1
20	KERN	ROSEDALE	115.00	115.00	SSP SWP T	1.71		1
21	7TH STANDARD	KERN	115.00	115.00	SSP OTHERS	6.75		1
22	WHEELER RIDGE	ADOBE SW STA	115.00	115.00	SWP SSP	1.34		1
23	KERN	TEVIS-STOCKDALE	115.00	115.00	SSP SWP T	16.04		1
24	KERN	TEVIS-STOCKDALE (21KV)	115.00	115.00	SSP SWP T	3.71		1
25	KERN	WESTPARK #1	115.00	115.00	SSP T	3.84		1
26	KERN	WESTPARK #2	115.00	115.00	T	3.83		1
27	KIFER	FMC	115.00	115.00	SSP T	6.01		1
28	FMC	SAN JOSE B	115.00	115.00	SSP	1.61		1
29	KINGS RIVER	SANGER-REEDLEY	115.00	115.00	SSP SWP T	43.35		1
30	RAINBOW TAP		115.00	115.00	SSP	2.59		1
31	KINGSBURG	CORCORAN #1	115.00	115.00	SSP T	27.16		1
32	KINGSBURG	WAUKENA SW STA	115.00	115.00	T	24.94		1
33	PENNGROVE SUB TAP		115.00	115.00	SWP	0.81		1
34	STONY POINT TAP		115.00	115.00	SWP SSP	3.08		1
35	LAKEVILLE	SONOMA #1	115.00	115.00	SWP SSP	6.68		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	LAKEVILLE	SONOMA #2	115.00	115.00	SWP SSP	7.18		1
2	LAKEWOOD	MEADOW LANE-CLAYTON	115.00	115.00	SSP SWP T	9.55		1
3	EBMUD TAP		115.00	115.00	OTHERS	0.02		1
4	LAKEWOOD	CLAYTON	115.00	115.00	SSP	5.52		1
5	LAWRENCE	MONTA VISTA	115.00	115.00	SSP SWP T	9.44		1
6	LE GRAND	DAIRYLAND	115.00	115.00	SSP SWP T	11.40		1
7	LE GRAND	CHOWCHILLA	115.00	115.00	SSP SWP T	10.94		1
8	CERTAINTEED TAP		115.00	115.00	SWP SSP	2.53		1
9	CHOWCHILLA #1 TAP		115.00	115.00	SWP	1.24		1
10	MENDOTA	NORTH STAR SOLAR	115.00	115.00		0.03		1
11	LERDO	FAMOSO	115.00	115.00	SSP SWP T	13.45		1
12	ULTRAPOWER (OGLE) TAP		115.00	115.00	OTHERS SSP	2.45		1
13	CAWELO C TAP		115.00	115.00	SWP SSP	1.33		1
14	LIVE OAK TAP		115.00	115.00	SWP	3.97		1
15	LIVE OAK	KERN OIL	115.00	115.00	T	4.40		1
16	VEDDER TAP		115.00	115.00	OTHERS SSP	11.09		1
17	VALLEY CHILDRENS		115.00	115.00		0.03		1
18	LLAGAS	GILROY FOODS	115.00	115.00	SWP	1.98		1
19	GILROY ENERGY TAP		115.00	115.00	SWP	0.28		1
20	CRAZY HORSE CANYON	SAN BENITO	115.00	115.00	SSP T	8.95		1
21	CRAZY HORSE CANYON	HOLLISTER	115.00	115.00	SSP	17.23		1
22	MADISON	VACA	115.00	115.00	SSP OTHERS	22.99		1
23	MANCHESTER	AIRWAYS-SANGER	115.00	115.00	SSP T	15.07		1
24	LAS PALMAS TAP		115.00	115.00	SWP SSP	0.85		1
25	MANTECA	VIERRA	115.00	115.00	SSP SWP T	3.98		1
26	HOWLAND ROAD TAP		115.00	115.00	SWP	0.90		1
27	HEINZ TAP		115.00		SWP	0.79		1
28	MARTIN	DALY CITY #1	115.00	115.00	T	3.93		1
29	MARTIN	DALY CITY #2	115.00	115.00		3.93		1
30	SERRAMONTE TAP		115.00	115.00	SSP T	2.55		1
31	MARTIN	EAST GRAND	115.00	115.00	SSP SWP T	3.96		1
32	MARTIN	MILLBRAE #1	115.00	115.00	SSP T	7.28		1
33	MARTIN	SF AIRPORT	115.00	115.00	SSP T	5.43		1
34	UNITED COGEN INC TAP		115.00	115.00	SWP SSP	0.68		1
35	MARTINEZ	SOBRANTE	115.00	115.00	SSP	16.40		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	FAIRVIEW	MARTINEZ SW STA	115.00	115.00	SWP	0.10		1
2	MCCALL	KINGSBURG #1	115.00	115.00	SSP SWP T	11.65		1
3	KINGSBURG COGEN TAP		115.00	115.00	SWP	1.22		1
4	GUARDIAN #2 TAP		115.00	115.00	SWP	0.13		1
5	MALAGA	KRCD	115.00	115.00	SWP	0.99		1
6	MCCALL	KINGSBURG #2	115.00	115.00	SSP	11.57		1
7	GUARDIAN #1 TAP		115.00	115.00	SWP	0.75		1
8	MCCALL	MALAGA	115.00	115.00	SSP SWP T	10.96		1
9	RANCHERS COTTON TAP		115.00	115.00	SWP SSP	2.10		1
10	RIO BRAVO (FRESNO) TAP		115.00	115.00	OTHERS SWP	0.32		1
11	AIR PRODUCTS TAP		115.00	115.00	SWP	0.29		1
12	MCCALL	REEDLEY	115.00	115.00	SSP OTHERS	15.20		1
13	MCCALL	SANGER #1	115.00	115.00	SSP T	9.23		1
14	MCCALL	SANGER #2	115.00	115.00		9.20		1
15	MCCALL	SANGER #3	115.00	115.00	SWP	8.30		1
16	CALIFORNIA AVE	MCCALL	115.00	115.00	SSP SWP T	23.66		1
17	WEST FRESNO	CALIFORNIA AVE	115.00	115.00	SWP T	4.90		1
18	DANISH CREAMERY TAP		115.00	115.00	SWP	1.20		1
19	MCCALL	WEST FRESNO #2	115.00	115.00	SSP T	19.61		1
20	MCKEE	PIERCY	115.00	115.00	T	7.75		1
21	LOS ESTEROS	MONTAGUE	115.00	115.00	SSP	4.64		1
22	MELONES	CURTIS	115.00	115.00	OTHERS SSP	14.80		1
23	PEORIA TAP		115.00	115.00	SWP SSP	0.85		1
24	CHINESE CAMP (ULTRA		115.00	115.00	SWP	2.07		1
25	RACETRACK TAP		115.00	115.00	SWP SSP	3.55		1
26	OCEANO	CALLENDER SW STA	115.00	115.00	SWP	4.22		1
27	MELONES	RACETRACK	115.00	115.00	SWP SSP	10.20		1
28	MENDOCINO	REDBUD	115.00	115.00		34.83		1
29	LUCERNE #2 TAP		115.00	115.00	SWP SSP	0.23		1
30	MENDOCINO	UKIAH	115.00	115.00	SSP OTHERS	9.83		1
31	MESA	DIVIDE #1	115.00	115.00	SSP T	14.71		1
32	MESA	DIVIDE #2	115.00	115.00		14.72		1
33	MESA	SANTA MARIA	115.00	115.00	SSP SWP T	4.36		1
34	FAIRWAY #1 TAP		115.00	115.00	OTHERS SSP	2.83		1
35	MESA	SISQUOC	115.00	115.00	SSP SWP T	17.60		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	SANTA MARIA COGEN TAP		115.00	115.00	SWP	0.24		1
2	METCALF	COYOTE PUMPING PLANT	115.00	115.00	SWP SSP	7.86		1
3	METCALF	EDENVALE #1	115.00	115.00	SSP T	5.73		1
4	IBM HARRY RD #2 TAP		115.00	115.00	SSP	0.58		1
5	AMES DISTRIBUTION	AMES	115.00	115.00	SSP	0.10		1
6	METCALF	EDENVALE #2	115.00	115.00	T	5.60		1
7	IBM BAILEY AVE TAP		115.00	115.00	SWP SSP	2.00		1
8	METCALF	EL PATIO #1	115.00	115.00	SSP T	14.39		1
9	IBM HARRY RD #1 TAP		115.00	115.00	T	0.58		1
10	METCALF	EL PATIO #2	115.00	115.00		14.40		1
11	METCALF	EVERGREEN #1	115.00	115.00	T	10.63		1
12	STONE	EVERGREEN-METCALF	115.00	115.00	SWP SSP	12.86		1
13	METCALF	GREEN VALLEY	115.00	115.00	SSP OTHERS	25.28		1
14	LOS ESTEROS	TRIMBLE	115.00	115.00	SSP	3.73		1
15	MONTAGUE	TRIMBLE	115.00	115.00	SSP	2.07		1
16	METCALF	MORGAN HILL	115.00	115.00	SSP	9.72		1
17	MIDSUN	MIDWAY	115.00	115.00	SSP OTHERS	18.86		1
18	CYMRIC TAP		115.00	115.00	SWP	0.18		1
19	MIDWAY	RENFRO-TUPMAN	115.00	115.00	SSP OTHERS	22.60		1
20	TUPMAN-NORCO TAP		115.00	115.00	SWP SSP	6.67		1
21	COLES LEVEE TAP		115.00	115.00	SWP	0.22		1
22	MIDWAY	TUPMAN-RIO	115.00	115.00	SSP OTHERS	26.59		1
23	FRITO LAY TAP		115.00	115.00	SWP SSP	0.53		1
24	GOLDEN VALLEY TAP		115.00	115.00	SWP SSP	1.59		1
25	MIDWAY	SHAFTER	115.00	115.00	SSP SWP T	13.63		1
26	MIDWAY	TAFT	115.00	115.00	SSP OTHERS	19.33		1
27	CHARCA	FAMOSO	115.00	115.00	SWP SSP	7.15		1
28	MIDWAY	TEMBLOR	115.00	115.00	SSP OTHERS	14.53		1
29	BELRIDGE TAP		115.00	115.00	SWP SSP	6.94		1
30	PSE MCKITTRICK TAP		115.00	115.00	SWP	5.21		1
31	MILLBRAE	SAN MATEO #1	115.00	115.00	SSP T	4.71		1
32	MILPITAS	SWIFT	115.00	115.00	SSP T	8.86		1
33	MABURY TAP		115.00	115.00	SWP SSP	2.81		1
34	LAS PLUMAS TAP		115.00	115.00	SWP SSP	0.48		1
35	MISSOURI FLAT	GOLD HILL #1	115.00	115.00	SSP T	19.73		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	MISSOURI FLAT	GOLD HILL #2	115.00	115.00	T	19.69		1
2	STELLING	WOLFE	115.00	115.00	SSP T	1.46		1
3	LOS ESTEROS	AGNEW	115.00	115.00	SWP SSP	1.37		1
4	MORAGA	CLAREMONT #1	115.00	115.00	OTHERS T	5.28		1
5	MORAGA	CLAREMONT #2	115.00	115.00	OTHERS T	5.30		1
6	MORAGA	OAKLAND #1	115.00	115.00	SSP T	5.04		1
7	MORAGA	OAKLAND #2	115.00	115.00		5.04		1
8	MORAGA	OAKLAND #3	115.00	115.00	SSP SWP T	5.05		1
9	MORAGA	OAKLAND #4	115.00	115.00	SWP	5.05		1
10	MORAGA	OAKLAND J	115.00	115.00	SWP	17.67		1
11	MORAGA	SAN LEANDRO #1	115.00	115.00	SSP T	11.14		1
12	MORAGA	SAN LEANDRO #2	115.00	115.00	SWP	11.01		1
13	MORAGA	SAN LEANDRO #3	115.00	115.00	SSP T	11.00		1
14	MORGAN HILL	LLAGAS	115.00	115.00	SWP T	10.84		1
15	MORRO BAY	SAN LUIS OBISPO #1	115.00	115.00	T	16.01		1
16	MORRO BAY	SAN LUIS OBISPO #2	115.00	115.00	T	16.02		1
17	GOLDTREE TAP		115.00	115.00	SWP	2.30		1
18	MOSS LANDING	DEL MONTE #1	115.00	115.00	SSP T	23.25		1
19	MOSS LANDING	DEL MONTE #2	115.00	115.00	SSP T	23.29		1
20	MOSS LANDING	GREEN VALLEY #1	115.00	115.00	SSP T	14.22		1
21	MOSS LANDING	GREEN VALLEY #2	115.00	115.00	SWP SSP	14.36		1
22	SARGENT SW STA	HOLLISTER	115.00	115.00	OTHERS SWP	1.54		1
23	MOSS LANDING	SALINAS #1	115.00	115.00	SSP T	11.99		1
24	DOLAN RD #1 TAP		115.00	115.00	SSP T	0.32		1
25	MOSS LANDING	SALINAS #2	115.00	115.00	SSP	12.03		1
26	DOLAN RD #2 TAP		115.00	115.00	SSP T	0.33		1
27	CRAZY HORSE CANYON	SALINAS-SOLEDAD #1	115.00	115.00	SSP T	35.35		1
28	SAN BENITO	HOLLISTER	115.00	115.00	SSP	8.31		1
29	CRAZY HORSE CANYON	SALINAS-SOLEDAD #2	115.00	115.00	SSP T	35.41		1
30	LLAGAS	HOLLISTER	115.00	115.00	SSP SWP T	21.56		1
31	MTN VIEW	MONTA VISTA	115.00	115.00		4.80		1
32	MOSS LANDING	CRAZY HORSE CANYON #1	115.00	115.00	SSP T	10.52		1
33	NEWARK	AMES #1	115.00	115.00	SSP T	8.30		1
34	NEWARK	AMES #2	115.00	115.00		8.28		1
35	NEWARK	AMES #3	115.00	115.00	SWP T	8.28		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	NEWARK	APPLIED MATERIALS	115.00	115.00	SSP OTHERS	11.37		1
2	LOCKHEED #2 TAP		115.00	115.00	OTHERS SSP	1.28		1
3	MOSS LANDING	CRAZY HORSE CANYON #2	115.00	115.00	SSP	10.60		1
4	NEWARK	DIXON LANDING	115.00	115.00	SSP	4.69		1
5	NEWARK	FREMONT #1	115.00	115.00	SSP T	3.71		1
6	NEWARK	FREMONT #2	115.00	115.00	SSP	3.75		1
7	NEWARK	JARVIS #1	115.00	115.00	SSP T	14.25		1
8	NEWARK	JARVIS #2	115.00	115.00	SSP T	14.48		1
9	NEWARK	KIFER	115.00	115.00	SSP T	10.61		1
10	ZANKER #2 TAP		115.00	115.00	SWP SSP	0.72		1
11	NEWARK	LAWRENCE	115.00	115.00	OTHERS T	10.25		1
12	LOCKHEED #1 TAP		115.00	115.00	SWP SSP	1.72		1
13	MOFFETT FIELD TAP		115.00	115.00	SWP	0.16		1
14	NEWARK	LAWRENCE LAB	115.00	115.00	T	12.21		1
15	NEWARK	MILPITAS #1	115.00	115.00	SSP T	8.48		1
16	NEWARK	MILPITAS #2	115.00	115.00	SWP SSP	10.30		1
17	NEWARK	NUMMI	115.00	115.00	SSP SWP T	4.94		1
18	NEWARK	NORTHERN RECEIVING	115.00	115.00	SSP T	8.76		1
19	NORTHERN RECEIVING	SCOTT #1	115.00	115.00	SSP T	2.08		1
20	NEWARK	NORTHERN RECEIVING	115.00	115.00	SSP T	8.67		1
21	NORTHERN RECEIVING	SCOTT #2	115.00	115.00	SSP	1.98		1
22	NEWARK	TRIMBLE	115.00	115.00	SSP T	12.36		1
23	ZANKER #1 TAP		115.00	115.00	SWP SSP	0.60		1
24	AGNEW TAP		115.00	115.00	SWP SSP	1.32		1
25	P	X #2	115.00	115.00	SSP T	0.28		1
26	NORTH TOWER	MARTINEZ JCT #1 (21KV)	115.00	115.00	T	2.61		1
27	OAKLAND C	MARITIME	115.00	115.00	SWP SSP	2.36		1
28	OAKLAND C	TURBINES	115.00	115.00	SWP SSP	0.19		1
29	OAKLAND J	GRANT	115.00	115.00	SSP T	14.81		1
30	EDES #2 TAP		115.00	115.00	SWP T	0.04		1
31	OLEUM	G #1	115.00	115.00	SSP T	11.29		1
32	VALLEY VIEW #1 TAP		115.00	115.00	SSP	0.96		1
33	OLEUM	G #2	115.00	115.00	OTHERS	11.30		1
34	VALLEY VIEW #2 TAP		115.00	115.00	SSP	0.97		1
35	OLEUM	MARTINEZ	115.00	115.00	SSP SWP T	10.50		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	OLEUM	NORTH TOWER-CHRISTIE	115.00	115.00	SSP OTHERS	8.33		1
2	CARIBOU	PALERMO	115.00	115.00	SSP OTHERS	54.89		1
3	PALERMO	BOGUE	115.00	115.00	SSP T	35.74		1
4	HONCUT TAP		115.00	115.00	SSP T	1.65		1
5	PALERMO	NICOLAUS	115.00	115.00	SSP OTHERS	41.18		1
6	PALERMO	PEASE	115.00	115.00	T	26.53		1
7	PANOCHE	MENDOTA	115.00	115.00	SWP SSP	10.08		1
8	CHENEY #1 TAP		115.00	115.00	SSP SWP T	4.10		1
9	PANOCHE	ORO LOMA	115.00	115.00	SSP SWP T	18.96		1
10	OXFORD TAP		115.00	115.00	SWP	3.87		1
11	WESTLANDS #1 RA		115.00	115.00	SWP SSP	1.05		1
12	SAN LUIS #5 TAP		115.00	115.00	SWP SSP	1.88		1
13	SAN LUIS #3 TAP		115.00	115.00	SSP SWP T	16.11		1
14	DE FRANCESCO TAP		115.00	115.00	SWP SSP	1.02		1
15	EXCELSIOR SW STA	FIVE POINTS PV	115.00	115.00		0.03		1
16	EXCELSIOR SW STA	SCHINDLER #1	115.00	115.00	SSP T	5.24		1
17	EXCELSIOR SW STA	SCHINDLER #2	115.00	115.00	SSP	5.23		1
18	PANOCHE	EXCELSIOR SW STA #1	115.00	115.00	SSP T	28.50		1
19	CANTUA TAP		115.00	115.00	OTHERS SSP	1.83		1
20	WESTLANDS #18 RA TAP		115.00	115.00	SWP SSP	3.52		1
21	KAMM TAP		115.00	115.00	OTHERS SWP	0.52		1
22	PANOCHE	EXCELSIOR SW STA #2	115.00	115.00	SSP	28.50		1
23	CHENEY #2 TAP		115.00	115.00	SWP SSP	1.97		1
24	PEASE	RIO OSO	115.00	115.00	SSP SWP T	27.61		1
25	SAN FRANCISCO #2		115.00	115.00		3.15		1
26	PITTSBURG	CLAYTON #1	115.00	115.00	SSP T	16.82		1
27	PITTSBURG	CLAYTON #3	115.00	115.00	SSP T	8.41		1
28	PITTSBURG	CLAYTON #4	115.00	115.00	SSP T	8.32		1
29	PITTSBURG	COLUMBIA STEEL	115.00	115.00	SSP T	9.23		1
30	COLUMBIA SOLAR 115kV		115.00	115.00	SWP SSP	0.45		1
31	LINDE TAP		115.00	115.00	SWP SSP	0.62		1
32	PITTSBURG	LOS MEDANOS #1	115.00	115.00	SSP	0.54		1
33	PITTSBURG	LOS MEDANOS #2	115.00	115.00	SSP	0.54		1
34	PITTSBURG	KIRKER-COLUMBIA STEEL	115.00	115.00	SSP	9.26		1
35	PITTSBURG	MARTINEZ #1	115.00	115.00	SSP T	17.22		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	BOLLMAN #1 TAP		115.00	115.00	SSP T	2.14		1
2	IMHOFF TAP		115.00	115.00	SWP SSP	1.43		1
3	PITTSBURG	MARTINEZ #2	115.00	115.00		15.83		1
4	BOLLMAN #2 TAP		115.00	115.00	SSP T	2.19		1
5	PLACER	GOLD HILL #1	115.00	115.00	SSP T	20.67		1
6	FLINT TAP		115.00	115.00	SSP SWP T	1.96		1
7	RAVENSWOOD	AMES #1	115.00	115.00	T	7.07		1
8	RAVENSWOOD	AMES #2	115.00	115.00		7.09		1
9	RAVENSWOOD	BAIR #1	115.00	115.00	T	7.43		1
10	SHREDDER TAP		115.00	115.00	SSP SWP T	1.38		1
11	RAVENSWOOD	BAIR #2	115.00	115.00	SSP T	11.29		1
12	RAVENSWOOD	COOLEY LANDING #1	115.00	115.00	T	1.62		1
13	RAVENSWOOD	COOLEY LANDING #2	115.00	115.00		1.62		1
14	RAVENSWOOD	PALO ALTO #1	115.00	115.00	SSP SWP T	4.28		1
15	RAVENSWOOD	PALO ALTO #2	115.00	115.00	SWP SSP	4.26		1
16	RAVENSWOOD	SAN MATEO	115.00	115.00	T	12.04		1
17	RIO OSO	NICOLAUS	115.00	115.00	T	5.39		1
18	RIO OSO	WEST SACRAMENTO	115.00	115.00	SSP SWP T	43.56		1
19	RIO OSO	WOODLAND #1	115.00	115.00	SSP OTHERS	45.25		1
20	RIO OSO	WOODLAND #2	115.00	115.00	SSP SWP T	53.37		1
21	ZAMORA TAP		115.00	115.00	SWP SSP	1.92		1
22	BELLOTA	RIVERBANK	115.00	115.00	OTHERS SSP	18.87		1
23	SALT SPRINGS	TIGER CREEK	115.00	115.00	SSP T	16.48		1
24	KM GREEN TAP		115.00	115.00	SSP	0.20		1
25	SAN JOSE A	SAN JOSE B	115.00	115.00	SSP	1.15		1
26	SAN LEANDRO	OAKLND J #1	115.00	115.00	SSP T	6.70		1
27	EDES #1 TAP		115.00	115.00	SWP SSP	0.05		1
28	SAN LUIS OBISPO	OCEANO	115.00	115.00	SSP OTHERS	19.90		1
29	SAN LUIS OBISPO	SANTA MARIA	115.00	115.00	SWP SSP	25.96		1
30	SAN MATEO	BAY MEADOWS #1	115.00	115.00	T	4.30		1
31	SAN MATEO	BAY MEADOWS #2	115.00	115.00	T	4.26		1
32	SAN MATEO	BELMONT	115.00	115.00	T SSP	7.20		1
33	SAN MATEO	MARTIN #3	115.00	115.00	SSP SWP T	11.55		1
34	SAN MATEO	MARTIN #6	115.00	115.00	SSP	11.68		1
35	SANGER	MALAGA	115.00	115.00	SWP SSP	8.82		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	SANTA MARIA	SISQUOC	115.00	115.00	SWP SSP	10.57		1
2	FAIRWAY #2 TAP		115.00	115.00		1.52		1
3	SEMITROPIC	CHARCA	115.00	115.00	SWP SSP	6.91		1
4	SEMITROPIC	MIDWAY #1	115.00	115.00	SSP SWP T	14.10		1
5	SEMITROPIC	MIDWAY #2	115.00	115.00	SSP OTHERS	20.11		1
6	WASCO PRISON TAP		115.00	115.00	SWP	0.54		1
7	SF AIRPORT	SAN MATEO	115.00	115.00	SSP T	6.09		1
8	SHAFTER	RIO BRAVO	115.00	115.00	SWP SSP	8.31		1
9	SIERRA #1		115.00	115.00	T	5.47		1
10	SIERRA #2		115.00	115.00		4.86		1
11	SISQUOC	GAREY	115.00	115.00	SWP SSP	5.02		1
12	SISQUOC	SANTA YNEZ SW STA	115.00	115.00	OTHERS SSP	22.12		1
13	SANTA YNEZ TAP		115.00	115.00	SWP SSP	4.06		1
14	SMYRNA	SEMITROPIC-MIDWAY	115.00	115.00	SSP OTHERS	44.63		1
15	SOBRANTE	G #1	115.00	115.00	SSP SWP T	5.34		1
16	SOBRANTE	G #2	115.00	115.00	SSP	5.39		1
17	SOBRANTE	GRIZZLY-CLAREMONT #1	115.00	115.00	SSP SWP T	19.58		1
18	MORAGA	LAKEWOOD	115.00	115.00	SSP T	15.11		1
19	SOBRANTE	MORAGA	115.00	115.00	SSP SWP T	5.68		1
20	SOBRANTE	GRIZZLY-CLAREMONT #2	115.00	115.00	SSP SWP T	19.30		1
21	SOBRANTE	R #1	115.00	115.00	SSP T	5.54		1
22	SOBRANTE	R #2	115.00	115.00		5.53		1
23	SOBRANTE	STANDARD OIL SW STA #2	115.00	115.00	SSP	18.89		1
24	SAN PABLO #2 TAP		115.00	115.00	SSP T	0.45		1
25	POINT PINOLE TAP		115.00	115.00	SWP SSP	1.30		1
26	SOBRANTE	STANDARD OIL SW STA #1	115.00	115.00	SSP OTHERS	18.89		1
27	SAN PABLO #1 TAP		115.00	115.00	SSP	0.44		1
28	SONOMA	PUEBLO	115.00	115.00	SWP SSP	18.48		1
29	STANISLAUS	MANTECA #2	115.00	115.00	SSP SWP T	53.95		1
30	STANISLAUS	MELONES SW	115.00	115.00	SSP SWP T	61.15		1
31	FROGTOWN #1 TAP		115.00	115.00	T	0.12		1
32	STANISLAUS	MELONES SW	115.00	115.00	SSP T	43.80		1
33	RIVERBANK JCT SW STA	MANTECA	115.00	115.00	SSP	17.65		1
34	RIPON TAP		115.00	115.00	SWP SSP	4.67		1
35	FROGTOWN #2 TAP		115.00	115.00		0.11		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	STANISLAUS	NEWARK #1 (12KV)	115.00	115.00	SSP T	15.04		1
2	STANISLAUS	NEWARK #2 (12KV)	115.00	115.00	SSP T	18.17		1
3	MONTA VISTA	WOLFE	115.00	115.00	SSP T	2.72		1
4	STOCKTON A	LOCKEFORD-BELLOTA #1	115.00	115.00	SSP OTHERS	34.77		1
5	STOCKTON A	LOCKEFORD-BELLOTA #2	115.00	115.00	SSP SWP T	34.49		1
6	KYOHO TAP		115.00	115.00	SWP SSP	2.20		1
7	SWIFT	METCALF	115.00	115.00	T	8.93		1
8	TABLE MTN	BUTTE #1	115.00	115.00	SSP SWP T	19.54		1
9	TABLE MTN	BUTTE #2	115.00	115.00	SSP T	15.82		1
10	TAFT	CHALK CLIFF	115.00	115.00	OTHERS SSP	7.18		1
11	UNIVERSITY COGEN TAP		115.00	115.00	SWP	0.22		1
12	TEMBLOR	KERNRIDGE	115.00	115.00	SWP SSP	4.78		1
13	CAL WATER TAP		115.00	115.00	SWP SSP	2.15		1
14	TEMBLOR	SAN LUIS OBISPO	115.00	115.00	SSP SWP T	57.79		1
15	CARRIZO PLAINS TAP		115.00	115.00	SSP	0.04		1
16	TESLA	SCHULTE SW STA #2	115.00	115.00	SSP T	7.34		1
17	OWENS ILLINOIS TAP		115.00	115.00	SWP	0.68		1
18	LAMMERS	KASSON	115.00	115.00	SSP SWP T	8.23		1
19	TESLA	SCHULTE SW STA #1	115.00	115.00	SSP OTHERS	7.39		1
20	LAWRENCE LIVERMORE		115.00	115.00	SWP T	9.41		1
21	AEC SITE #1 TAP		115.00	115.00	OTHERS T	1.60		1
22	AEC SITE #2 TAP		115.00	115.00	SWP SSP	2.16		1
23	SAFEWAY TAP		115.00	115.00	SWP SSP	0.68		1
24	TESLA	SALADO #1	115.00	115.00	SSP OTHERS	32.07		1
25	MILLER #1 TAP		115.00	115.00	SSP SWP T	21.26		1
26	SCHULTE SW STA	LAMMERS	115.00	115.00	SSP T	0.69		1
27	TESLA	SALADO-MANTECA	115.00	115.00	SSP OTHERS	53.96		1
28	INGRAM CREEK TAP		115.00	115.00	SWP SSP	0.50		1
29	MILLER #2 TAP		115.00	115.00	OTHERS SSP	12.32		1
30	TESLA	STOCKTON COGEN JCT	115.00	115.00	SSP SWP T	44.47		1
31	THERMAL ENERGY TAP		115.00	115.00	SWP SSP	0.74		1
32	SAN JOAQUIN COGEN TAP		115.00	115.00	SWP	0.04		1
33	TESLA	TRACY	115.00	115.00	SSP SWP T	25.23		1
34	ELLIS TAP		115.00	115.00	SWP	0.17		1
35	TRIMBLE	SAN JOSE B	115.00	115.00	SSP	2.53		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	GISH TAP		115.00	115.00	SWP	0.96		1
2	LOS ESTEROS	NORTECH	115.00	115.00	SSP	1.98		1
3	TRINITY	COTTONWOOD	115.00	115.00	SSP OTHERS	45.97		1
4	JESSUP TAP		115.00	115.00	OTHERS SSP	0.86		1
5	UKIAH	HOPLAND-CLOVERDALE	115.00	115.00	OTHERS SSP	31.17		1
6	VACA	SUISUN	115.00	115.00	SSP SWP T	23.06		1
7	VACA	SUISUN-JAMESON	115.00	115.00	SSP SWP T	25.46		1
8	VACA	VACAVILLE-CORDELIA	115.00	115.00	SWP T	22.04		1
9	VACA	VACAVILLE-JAMESON-NOR	115.00	115.00	SSP SWP T	36.18		1
10	WEST SACRAMENTO	BRIGHTON	115.00	115.00	SSP T	13.97		1
11	DEEPWATER #2 TAP		115.00	115.00	SWP SSP	2.45		1
12	WEST SACRAMENTO	DAVIS	115.00	115.00	OTHERS SSP	12.14		1
13	DEEPWATER #1 TAP		115.00	115.00	SSP T	2.29		1
14	POST OFFICE TAP		115.00	115.00	SWP SSP	0.75		1
15	WESTPARK	MAGUNDEN	115.00	115.00	SSP SWP T	12.29		1
16	BEAR MTN TAP		115.00	115.00	SWP SSP	1.27		1
17	BOLTHOUSE FARMS TAP		115.00	115.00	SWP	0.11		1
18	ADOBE SW STA	LAMONT	115.00	115.00	SSP SWP T	21.20		1
19	ARVIN EDISON TAP		115.00	115.00	SWP	1.06		1
20	WHISMAN	MTN VIEW	115.00	115.00	SWP T	3.54		1
21	WILSON	ATWATER #2	115.00	115.00	SSP T	15.41		1
22	WILSON	LE GRAND	115.00	115.00	SSP OTHERS	14.04		1
23	WILSON	MERCED #1	115.00	115.00	SSP SWP T	5.58		1
24	WILSON	MERCED #2	115.00	115.00	SSP SWP T	6.20		1
25	WILSON	ORO LOMA	115.00	115.00	SSP SWP T	43.56		1
26	WOODLAND	DAVIS	115.00	115.00	SWP SSP	11.71		1
27	WOODLAND BIOMASS TAP		115.00	115.00	SWP	0.87		1
28	WOODLEAF	PALERMO	115.00	115.00	SSP OTHERS	19.62		1
29	SLY CREEK TAP		115.00	115.00	OTHERS SSP	5.34		1
30	FORBESTOWN TAP		115.00	115.00	OTHERS SSP	0.22		1
31	KANAKA TAP		115.00	115.00	OTHERS SSP	2.59		1
32	CAL PEAK	VACA	115.00	115.00	SWP	0.11		1
33	LAWRENCE LIVERMORE		115.00	115.00	SSP SWP T	9.00		1
34	OLEUM	UNOCAL #1	115.00	115.00		0.01		1
35	OLEUM	UNOCAL #2	115.00	115.00	SWP	0.05		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	UNION OIL TAP		115.00	115.00	SWP SSP	0.50		1
2	PLACER	GOLD HILL #2	115.00	115.00	SSP	20.67		1
3	APPLIED MATERIALS	BRITTON	115.00	115.00	SSP	0.47		1
4	SANTA ROSA	CORONA	115.00	115.00	SWP SSP	14.39		1
5	VIERRA	TRACY-KASSON	115.00	115.00	SSP SWP T	10.49		1
6	CORONA	LAKEVILLE	115.00	115.00	SWP SSP	5.79		1
7	NOTRE DAME	BUTTE	115.00	115.00	SWP SSP	2.02		1
8	NEWARK	AMES DISTRIBUTION	115.00	115.00	SWP SSP	8.25		1
9	SYCAMORE CREEK	NOTRE DAME-TABLE MTN	115.00	115.00	SWP SSP	20.33		1
10	PALERMO	WYANDOTTE	115.00	115.00	SSP SWP T	5.30		1
11	PARADISE	TABLE MTN	115.00	115.00	SSP OTHERS	33.73		1
12	METCALF	HICKS 1 & 2	115.00	115.00	SSP T	6.62		1
13	PIERCY	METCALF	115.00	115.00	T	4.72		1
14	GEYSERS #11	EAGLE ROCK	115.00	115.00	SSP	0.64		1
15	EAGLE ROCK	FULTON-SILVERADO	115.00	115.00	SSP T	46.94		1
16	DRUM	HIGGINS	115.00	115.00	SSP OTHERS	47.75		1
17	BELL	PLACER	115.00	115.00	SWP T	7.94		1
18	PARADISE	BUTTE	115.00	115.00	OTHERS SSP	13.58		1
19	ATLANTIC	PLEASANT GROVE #1	115.00	115.00	SSP SWP T	5.33		1
20	DRUM PH #2 TAP		115.00	115.00	SWP SSP	0.09		1
21	UC DAVIS #1 TAP		115.00	115.00	SWP SSP	1.64		1
22	UC DAVIS #2 TAP		115.00	115.00	SWP SSP	1.61		1
23	CHCF TAP		115.00	115.00	SWP SSP	3.00		1
24	EASTSHORE	CERBERUS	115.00	115.00	SSP	0.48		1
25	LINCOLN	PLEASANT GROVE	115.00	115.00	OTHERS SSP	7.38		1
26	SIERRA PACIFIC IND TAP		115.00	115.00	SWP	0.06		1
27	SCHULTE SW STA	KASSON-MANTECA	115.00	115.00	SSP SWP T	16.58		1
28	SAN MATEO	MARTIN #4	115.00	115.00	SWP SSP	11.64		1
29	SANTA PAULA	MILLBRAE	115.00	115.00	SSP	0.09		1
30	RIO BRAVO (ROCKLIN) TAP		115.00	115.00	SWP	0.40		1
31	RIO BRAVO TOMATO TAP		115.00	115.00	OTHERS SSP	0.43		1
32	WAUKENA SW STA	CORCORAN	115.00	115.00		2.37		1
33	SANGER	CALIFORNIA AVE	115.00	115.00	SWP SSP	9.33		1
34	SANGER	REEDLEY	115.00	115.00	SWP SSP	20.42		1
35	SANGER COGEN TAP		115.00	115.00	SWP SSP	0.83		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	ATLANTIC	PLEASANT GROVE #2	115.00	115.00	SWP SSP	5.36		1
2	GOLD HILL	CLARKSVILLE	115.00	115.00	SSP T	5.77		1
3	C	X #3	115.00	115.00	N/A	3.67		1
4	H	P #4	115.00	115.00	N/A	5.16		1
5	LAKEVILLE	SONOMA #1	115.00	115.00	N/A	0.55		1
6	A	P #1	115.00	115.00	N/A	2.46		1
7	A	H-W #1	115.00	115.00	N/A	4.95		1
8	A	X #1	115.00	115.00	N/A	2.67		1
9	A	Y #1	115.00	115.00	N/A	3.33		1
10	A	Y #2	115.00	115.00	N/A	2.85		1
11	H	P #1	115.00	115.00	N/A	3.80		1
12	A	H-W #2	115.00	115.00	N/A	5.06		1
13	H	Y #1	115.00	115.00	N/A	7.23		1
14	H	P #3	115.00	115.00	N/A	3.59		1
15	P	X #1	115.00	115.00	N/A	4.01		1
16	P	X #2 (UNDERGROUND)	115.00	115.00	N/A	3.95		1
17	X	Y #1	115.00	115.00	N/A	0.57		1
18	C	L #1	115.00	115.00	N/A	1.10		1
19	C	X #2	115.00	115.00	N/A	3.38		1
20	D	L #1	115.00	115.00	N/A	2.31		1
21	SOBRANTE	R #1	115.00	115.00	N/A	4.16		1
22	SOBRANTE	R #2	115.00	115.00	N/A	4.11		1
23	K	D #1	115.00	115.00	N/A	2.44		1
24	K	D #2	115.00	115.00	N/A	2.57		1
25	EBMUD TAP		115.00	115.00	N/A	0.94		1
26	SAN MATEO	MARTIN #4	115.00	115.00	N/A	0.21		1
27	SAN MATEO	MARTIN #3	115.00	115.00	N/A	0.21		1
28	EAST GRAND	SAN MATEO	115.00	115.00	N/A	0.22		1
29	MARTIN	MILLBRAE #1	115.00	115.00	N/A	0.22		1
30	MARTIN	SF AIRPORT	115.00	115.00	N/A	0.23		1
31	SAN MATEO	MARTIN #6	115.00	115.00	N/A	0.23		1
32	TRIMBLE	SAN JOSE B	115.00	115.00	N/A	1.11		1
33	KIFER	FMC	115.00	115.00	N/A	1.11		1
34	NEWARK	APPLIED MATERIALS	115.00	115.00	N/A	0.74		1
35	APPLIED MATERIALS	BRITTON	115.00	115.00	N/A	0.74		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	STELLING	MONTA VISTA	115.00	115.00	N/A	1.14		1
2	MONTA VISTA	WOLFE	115.00	115.00	N/A	1.12		1
3	PITTSBURG	LOS MEDANOS #1	115.00	115.00	N/A	0.88		1
4	PITTSBURG	LOS MEDANOS #2	115.00	115.00	N/A	0.89		1
5	CRESCENT SW STA	SCULPIN PV	70.00		SSP	0.04		1
6	FIVE POINTS SW	WHITNEY POINT PV	70.00	70.00	SSP	0.06		1
7	AERA ENERGY TAP		70.00	60.00	SWP SSP	0.35		1
8	ARCO	CARNERAS	70.00	70.00	SWP SSP	17.97		1
9	ARCO	CHOLAME	70.00	70.00	SWP SSP	26.74		1
10	BERRENDA A TAP		70.00	70.00	SWP	2.25		1
11	ANTELOPE TAP		70.00	70.00	SWP SSP	4.33		1
12	BERRENDA C TAP		70.00	70.00	SWP	1.87		1
13	ARCO	POLONIO PASS PP	70.00	70.00	SWP SSP	21.27		1
14	LOST HILLS TAP		70.00	70.00	SWP SSP	2.89		1
15	BADGER HILL TAP		70.00	70.00	SWP	1.56		1
16	ARCO	TULARE LAKE	70.00	70.00	SWP SSP	16.11		1
17	LAS PERILLAS TAP		70.00	70.00	SWP	0.39		1
18	ARCO	TWISSELMAN	70.00	70.00	SWP SSP	6.52		1
19	TEXACO (LOST HILLS) TAP		70.00	70.00	SWP	0.01		1
20	CHEVRON (LOST HILLS)		70.00	70.00	SWP	14.75		1
21	ATASCADERO	CAYUCOS	70.00	70.00	OTHERS SSP	11.80		1
22	ATASCADERO	SAN LUIS OBISPO	70.00	70.00	SSP OTHERS	15.47		1
23	BORDEN	COPPERMINE	70.00	70.00	SWP SSP	19.95		1
24	RIVER ROCK TAP		70.00	70.00	SWP	1.21		1
25	BORDEN	GLASS	70.00	70.00	SWP SSP	6.62		1
26	BORDEN	MADERA #2	70.00	70.00	OTHERS SSP	5.81		1
27	CALIFORNIA AVE	KEARNEY	70.00	70.00	SWP	3.20		1
28	CARNERAS	TAFT	70.00	70.00	OTHERS SSP	34.92		1
29	CELERON TAP		70.00	70.00	SWP	0.04		1
30	LIGHTNER TAP		70.00	70.00	SWP	3.06		1
31	CARUTHERS	LEMOORE NAS-CAMDEN	70.00	70.00	SWP SSP	25.17		1
32	CAYUCOS	CAMBRIA	70.00	70.00	OTHERS SSP	17.73		1
33	COALINGA #1	COALINGA #2	70.00	70.00	OTHERS SSP	8.61		1
34	COALINGA COGEN TAP		70.00	70.00	SWP SSP	4.91		1
35	TORNADO TAP		70.00	70.00	SWP	0.06		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	DERRICK TAP		70.00	70.00	SWP	0.85		1
2	OIL CITY TAP		70.00	70.00	SWP	0.05		1
3	PENN ZIER TAP		70.00	70.00	SWP	4.99		1
4	COALINGA #1	SAN MIGUEL	70.00	70.00	SSP SWP T	38.01		1
5	COPPERMINE	TIVY VALLEY	70.00	70.00	OTHERS SSP	24.01		1
6	CORCORAN	ANGIOLA	70.00	70.00	SWP SSP	8.94		1
7	BOSWELL TAP		70.00	70.00	SWP	1.39		1
8	DINUBA	OROSI	70.00	70.00	SWP SSP	9.83		1
9	STONE CORRAL TAP		70.00	70.00	SWP SSP	7.56		1
10	DIVIDE	VANDENBERG #1	70.00	70.00	OTHERS SWP	6.64		1
11	DIVIDE	VANDENBERG #2	70.00	70.00	OTHERS SWP	6.57		1
12	DIVIDE	ZACA-LOMPOC (12KV)	70.00	70.00	SWP	10.55		1
13	EXCHEQUER	MARIPOSA	70.00	70.00	SSP SWP T	19.48		1
14	EXCHEQUER	YOSEMITE	70.00	70.00	SSP OTHERS	34.91		1
15	BRICEBURG		70.00	70.00	SWP SSP	7.78		1
16	GATES	JAYNE SW STA	70.00	70.00	SWP SSP	0.68		1
17	CAMDEN	KINGSBURG	70.00	70.00	SWP SSP	14.91		1
18	FRIANT	COPPERMINE	70.00	70.00	SWP	8.30		1
19	JAYNE SW STA	COALINGA	70.00	70.00	SWP SSP	11.81		1
20	GATES	COALINGA #2	70.00	70.00	SWP SSP	17.26		1
21	GATES	HURON	70.00	70.00	SSP SWP T	4.50		1
22	GATES	TULARE LAKE	70.00	70.00	OTHERS SSP	18.34		1
23	KETTLEMAN HILLS TAP		70.00	70.00	SWP SSP	1.02		1
24	AVENAL TAP		70.00	70.00	OTHERS SSP	5.40		1
25	CHEVRON PIPELINE		70.00	70.00	SWP	1.17		1
26	BORDEN	MADERA #1	70.00	70.00	SWP SSP	4.91		1
27	GUERNSEY	HENRIETTA	70.00	70.00	SWP SSP	18.44		1
28	RESERVE OIL TAP		70.00	70.00	SWP	0.58		1
29	ARMSTRONG TAP		70.00	70.00	SWP	0.44		1
30	GWF HANFORD COGEN		70.00	70.00	SWP	0.32		1
31	HAAS	WOODCHUCK	70.00	70.00	SWP SSP	6.79		1
32	HELM	KERMAN	70.00	70.00	SWP SSP	13.25		1
33	FRESNO COGEN (AGRICO)		70.00	70.00	SWP	3.17		1
34	HELM	CRESCENT SW STA	70.00	70.00	SWP SSP	4.92		1
35	HELM	STROUD	70.00	70.00	SWP	7.43		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	HENRIETTA	LEMOORE	70.00	70.00	SWP SSP	9.37		1
2	LEPRINO TAP		70.00	70.00	SWP	0.47		1
3	GWF	HENRIETTA	70.00	70.00	OTHERS SWP	0.12		1
4	HENRIETTA	LEMOORE NAS	70.00	70.00	SWP SSP	1.69		1
5	KENT SW STA	TULARE LAKE	70.00	70.00	SSP SWP T	15.93		1
6	HENRIETTA	KENT SW STA	70.00	70.00	SWP SSP	1.47		1
7	HERDLYN	TRACY	70.00	70.00	SWP	2.06		1
8	KEARNEY	BIOLA	70.00	70.00	SWP SSP	19.13		1
9	KEARNEY	BOWLES	70.00	70.00	SWP SSP	9.29		1
10	KEARNEY	CARUTHERS	70.00	70.00	SWP SSP	12.05		1
11	KEARNEY	KERMAN	70.00	70.00	SWP SSP	10.98		1
12	KERN CANYON	MAGUNDEN-WEEDPATCH	70.00	70.00	SSP SWP T	20.69		1
13	MARICOPA	COPUS	70.00	70.00	SWP SSP	7.86		1
14	KERN	FRUITVALE	70.00	70.00	SWP T	0.16		1
15	KERN	KERN OIL-FAMOSO	70.00	70.00	SSP SWP T	24.69		1
16	CAWELO B TAP		70.00	70.00	SWP	0.40		1
17	KERN	MAGUNDEN	70.00	70.00	SSP SWP T	20.61		1
18	FRUITVALE TAP		70.00	70.00	SWP T	0.12		1
19	EISEN TAP		70.00	70.00	SWP	1.86		1
20	KERN	OLD RIVER #1	70.00	70.00	SSP OTHERS	11.94		1
21	KERN	OLD RIVER #2	70.00	70.00	SWP SSP	23.07		1
22	CARNATION TAP		70.00	70.00	SWP SSP	0.61		1
23	KINGSBURG	LEMOORE	70.00	70.00	SSP SWP T	27.49		1
24	HARDWICK TAP		70.00	70.00	SWP	2.74		1
25	LIVINGSTON	LIVINGSTON JCT	70.00	70.00	SWP SSP	23.36		1
26	LOS BANOS	MERCY SPRINGS SW STA	70.00	70.00	SSP SWP T	14.73		1
27	MERCY SPRINGS SW STA	CANAL-ORO LOMA	70.00	70.00	SWP SSP	23.32		1
28	WRIGHT TAP		70.00	70.00	SWP	1.18		1
29	ARBURUA TAP		70.00	70.00	SWP SSP	3.57		1
30	LOS BANOS	LIVINGSTON JCT-CANAL	70.00	70.00	SWP SSP	14.29		1
31	LOS BANOS	O'NEILL PGP	70.00	70.00	SSP SWP T	3.88		1
32	LOS BANOS	PACHECO	70.00	70.00	SSP OTHERS	20.78		1
33	DINOSAUR POINT TAP		70.00	70.00	OTHERS SSP	2.00		1
34	COPUS	OLD RIVER	70.00	70.00	SWP SSP	19.61		1
35	GARDNER TAP		70.00	70.00	SWP	3.77		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	TEXACO BASIC SCHOOL		70.00	70.00	SWP	0.75		1
2	PENTLAND TAP		70.00	70.00	SWP	0.55		1
3	MENDOTA	SAN JOAQUIN-HELM	70.00	70.00	SWP SSP	26.96		1
4	MENDOTA BIOMASS TAP		70.00	70.00	SWP SSP	3.84		1
5	WESTLANDS TAP		70.00	70.00	SWP	1.07		1
6	WESIX TAP		70.00	70.00	SWP	2.51		1
7	GIFFEN TAP		70.00	70.00	SWP SSP	4.95		1
8	MERCED FALLS	EXCHEQUER	70.00	70.00	SSP T	6.51		1
9	MCSWAIN TAP		70.00	70.00	SWP	1.37		1
10	MERCED #1		70.00	70.00	SSP SWP T	39.88		1
11	MERCED	MERCED FALLS	70.00	70.00	SSP OTHERS	20.93		1
12	ORO LOMA	CANAL #1	70.00	70.00	SSP SWP T	24.56		1
13	ORO LOMA	MENDOTA	70.00	70.00	SWP SSP	29.58		1
14	TULE	SPRINGVILLE	70.00	70.00	OTHERS SSP	15.24		1
15	REEDLEY	DINUBA #1	70.00	70.00	SWP SSP	7.70		1
16	DINUBA ENERGY TAP		70.00	70.00	SWP	3.16		1
17	REEDLEY	OROSI	70.00	70.00	SWP SSP	10.89		1
18	DUNLAP TAP		70.00	70.00	SWP SSP	16.21		1
19	RIO BRAVO HYDRO		70.00	70.00	SWP	0.24		1
20	SAN BERNARD	TEJON	70.00	70.00	SWP SSP	6.96		1
21	SAN LUIS OBISPO	CAYUCOS	70.00	70.00	OTHERS SSP	23.39		1
22	MUSTANG TAP		70.00	70.00	SWP SSP	0.71		1
23	SAN LUIS OBISPO	SANTA MARIA *	70.00	70.00	SWP SSP	13.33		1
24	SANGER	CALIFORNIA AVE #1	70.00	70.00	SWP SSP	9.23		1
25	SCHINDLER	COALINGA #2	70.00	70.00	SWP SSP	17.26		1
26	FIVE POINTS SW STA	HURON-GATES	70.00	70.00	SSP SWP T	19.78		1
27	SCHINDLER	FIVE POINTS SW STA	70.00	70.00	SWP SSP	1.70		1
28	SEMITROPIC	WASCO	70.00	70.00	SSP SWP T	6.32		1
29	MCFARLAND TAP		70.00	70.00	SWP	5.99		1
30	CRESCENT SW STA	SCHINDLER	70.00	70.00	SWP SSP	10.80		1
31	CRESCENT SW STA	STROUD	70.00	70.00	SWP SSP	3.61		1
32	TAFT	CUYAMA #1	70.00	70.00	SWP SSP	19.25		1
33	TAFT	CUYAMA #2	70.00	70.00	SWP SSP	18.75		1
34	TAFT	ELK HILLS	70.00	70.00	SWP SSP	12.39		1
35	TEXACO BUENA VISTA		70.00	70.00	SWP	0.10		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	TAFT	MARICOPA	70.00	70.00	OTHERS T	5.98		1
2	SOLAR TANNEHILL TAP		70.00	70.00	SWP	2.65		1
3	CADET TAP		70.00	70.00	SWP	0.12		1
4	MOCO TAP		70.00	70.00	SWP	1.64		1
5	WASCO	FAMOSO	70.00	70.00	SWP SSP	7.13		1
6	TEJON	LEBEC	70.00	70.00	SWP SSP	13.00		1
7	ROSE TAP		70.00	70.00	SWP	0.31		1
8	GRAPEVINE TAP		70.00	70.00	SWP	0.14		1
9	CASTAIC TAP		70.00	70.00	SWP	0.02		1
10	TIVY VALLEY	REEDLEY	70.00	70.00	SWP	12.30		1
11	WEEDPATCH	SAN BERNARD	70.00	70.00	SWP SSP	9.27		1
12	WEEDPATCH	WELLFIELD	70.00	70.00	SWP SSP	5.89		1
13	SYCAMORE TAP		70.00	70.00	SWP SSP	2.04		1
14	WHEELER RIDGE	LAKEVIEW	70.00	70.00	SWP SSP	7.51		1
15	EMIDIO TAP		70.00	70.00	SWP	3.07		1
16	KELLEY TAP		70.00	70.00	SWP	2.79		1
17	WHEELER RIDGE	SAN BERNARD	70.00	70.00	SWP SSP	5.88		1
18	WHEELER RIDGE	TEJON	70.00	70.00	SWP T	5.01		1
19	TECUYA TAP		70.00	70.00	SWP SSP	1.91		1
20	WHEELER RIDGE	WEEDPATCH	70.00	70.00	SWP SSP	22.38		1
21	WISHON	COPPERMINE	70.00	70.00	SSP SWP T	19.99		1
22	AUBERRY TAP		70.00	70.00	SWP SSP	2.29		1
23	WISHON	SAN JOAQUIN #3	70.00	70.00	OTHERS SSP	7.68		1
24	YANKE (NORTH FORK) TAP		70.00	70.00	SWP	0.44		1
25	BIOLA	GLASS-MADERA	70.00	70.00	OTHERS SSP	18.84		1
26	CANANDAIGUA WINERY		70.00	70.00	SWP	0.29		1
27	BONITA TAP		70.00	70.00	SWP SSP	3.04		1
28	EL PECO TAP		70.00	70.00	SWP	3.02		1
29	CORCORAN	GUERNSEY	70.00	70.00	SWP SSP	13.49		1
30	KEARNEY TIE		70.00	70.00	SWP T	0.15		1
31	KEARNEY ALTERNATE TIE		70.00	70.00	SWP T	0.30		1
32	SAN MIGUEL	PASO ROBLES	70.00	70.00	SWP SSP	9.92		1
33	PASO ROBLES	TEMPLETON	70.00	70.00	OTHERS SSP	4.90		1
34	TEMPLETON	ATASCADERO	70.00	70.00	SWP SSP	8.82		1
35	BORDEN	GLASS; XLPE; 70 KV	70.00	70.00	N/A	0.39		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	FULTON	WINDSOR	60.00	60.00	SWP SSP	6.59		1
2	IGNACIO	STAFFORD	60.00		SWP SSP	6.13		1
3	DEL MAR	ATLANTIC #1	60.00	60.00	SWP SSP	2.78		1
4	FORT BRAGG	ELK	60.00	60.00	OTHERS SSP	24.02		1
5	WEST SAC COM TOWERS		60.00	60.00	SSP T	0.02		1
6	ALMENDRA JCT	NICOLAUS	60.00	60.00	SWP SSP	24.90		1
7	DEL MAR	ATLANTIC #2	60.00	60.00	SWP SSP	4.45		1
8	BAIR	COOLEY LANDING #1	60.00	60.00	SSP SWP T	5.55		1
9	BELLE HAVEN #1 TAP		60.00	60.00	SWP SSP	0.45		1
10	BAIR	COOLEY LANDING #2	60.00	60.00	T	5.60		1
11	BELLE HAVEN #2 TAP		60.00	60.00	SWP	0.40		1
12	BRIDGEVILLE	GARBERVILLE	60.00	60.00	OTHERS SSP	36.16		1
13	FRUITLAND TAP		60.00	60.00	SWP SSP	4.26		1
14	FORT SEWARD TAP		60.00	60.00	OTHERS SSP	7.70		1
15	BURNS	LONE STAR #1	60.00	60.00	OTHERS SSP	5.44		1
16	LONE STAR TAP		60.00	60.00	SWP	1.18		1
17	BURNS	LONE STAR #2	60.00	60.00	OTHERS SSP	6.31		1
18	CRUSHER TAP		60.00	60.00	SWP SSP	1.94		1
19	BUTTE	CHICO #1	60.00	60.00	SWP	0.79		1
20	BUTTE	CHICO #2	60.00	60.00	SWP	0.74		1
21	BUTTE	ESQUON	60.00	60.00	SWP SSP	9.87		1
22	CARIBOU #2		60.00	60.00	OTHERS SSP	42.08		1
23	CARIBOU	PLUMAS JCT	60.00	60.00	OTHERS SSP	21.26		1
24	PLUMAS-SIERRA TAP		60.00	60.00	SWP	0.75		1
25	SIERRA PAC IND (QUINCY)		60.00	60.00	SWP	0.17		1
26	CARIBOU	WESTWOOD	60.00	60.00	OTHERS SSP	21.10		1
27	CASCADE	BENTON-DESCHUTES	60.00	60.00	OTHERS SSP	15.98		1
28	WINTU TAP		60.00	60.00	SWP	1.86		1
29	CENTERVILLE	TABLE MTN	60.00	60.00	OTHERS SSP	21.50		1
30	CENTERVILLE	TABLE MTN-OROVILLE	60.00	60.00	OTHERS SSP	26.11		1
31	CHICO A	DAYTON RD	60.00		SWP	0.80		1
32	CHRISTIE	FRANKLIN #1	60.00	60.00	OTHERS SSP	5.01		1
33	UNION CHEMICAL TAP		60.00	60.00	SWP	1.04		1
34	CHRISTIE	FRANKLIN #2	60.00	60.00	OTHERS SSP	5.11		1
35	SEQUOIA TAP		60.00	60.00	SWP	0.40		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	CHRISTIE	WILLOW PASS	60.00	60.00	SSP OTHERS	15.93		1
2	PORT COSTA BRICK TAP		60.00	60.00	OTHERS SSP	0.05		1
3	PORT COSTA BRICK TAP		60.00	60.00	OTHERS SSP	1.84		1
4	STAUFFER TAP		60.00	60.00	SWP SSP	0.58		1
5	URICH TAP		60.00	60.00	SWP	0.21		1
6	KONOCTI	MIDDLETOWN	60.00	60.00	OTHERS SSP	19.87		1
7	CLEAR LAKE	HOPLAND	60.00	60.00	OTHERS SSP	11.54		1
8	COBURN	BASIC ENERGY	60.00	60.00	SWP	3.39		1
9	COBURN	OIL FIELDS #1	60.00	60.00	SWP SSP	29.46		1
10	TEXACO TAP		60.00	60.00	SWP SSP	0.72		1
11	COBURN	OIL FIELDS #2	60.00	60.00	SWP SSP	31.05		1
12	SAN ARDO TAP		60.00	60.00	SWP SSP	0.34		1
13	COLEMAN	COTTONWOOD	60.00	60.00	OTHERS SSP	8.58		1
14	COLEMAN	RED BLUFF	60.00	60.00	SWP SSP	48.31		1
15	COLEMAN	SOUTH	60.00	60.00	SWP SSP	13.39		1
16	COLGATE PH	COLGATE SW STA	60.00	60.00	SSP	0.19		1
17	COLGATE	ALLEGHANY	60.00	60.00	OTHERS SSP	24.55		1
18	COLGATE	CHALLENGE	60.00	60.00	OTHERS SSP	13.04		1
19	COLGATE	GRASS VALLEY	60.00	60.00	OTHERS SSP	13.17		1
20	COLGATE	PALERMO	60.00	60.00	OTHERS SSP	22.65		1
21	COLGATE	SMARTVILLE #1	60.00	60.00	OTHERS SSP	11.26		1
22	NARROWS #1 TAP		60.00	60.00	OTHERS SSP	2.65		1
23	COLGATE	SMARTVILLE #2	60.00	60.00	OTHERS SSP	11.19		1
24	NARROWS #2 TAP		60.00	60.00	OTHERS SSP	3.10		1
25	SMARTVILLE TAP		60.00	60.00	SWP	0.09		1
26	CONTRA COSTA	DU PONT	60.00	60.00	SWP T	2.65		1
27	GWF #4 TAP		60.00	60.00	SWP T	0.25		1
28	CONTRA COSTA	PITTSBURG	60.00	60.00	SSP SWP T	6.28		1
29	CONTRA COSTA	SHELL CHEMICAL#1(21KV)	60.00	60.00		9.55		1
30	PITTSBURG #1 TAP (NO		60.00	60.00	SSP	1.15		1
31	COOLEY LANDING	LOS ALTOS	60.00	60.00	SSP SWP T	14.89		1
32	COOLEY LANDING	LOS ALTOS (I2KV)	60.00	60.00	SSP SWP T	1.41		1
33	WESTINGHOUSE TAP		60.00	60.00	SWP T	7.97		1
34	COOLEY LANDING	STANFORD	60.00	60.00	SWP SSP	6.04		1
35	MENLO TAP		60.00	60.00	SWP	0.36		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	CORTINA #1		60.00	60.00	SWP SSP	26.29		1
2	HARRINGTON TAP		60.00	60.00	SWP	0.53		1
3	CORTINA #2		60.00	60.00	SWP SSP	26.61		1
4	ARBUCKLE TAP		60.00	60.00	SWP SSP	0.82		1
5	CORTINA #3		60.00	60.00	SWP SSP	24.80		1
6	WADHAM TAP		60.00	60.00	SWP	1.68		1
7	CORTINA #4		60.00	60.00	SWP SSP	45.28		1
8	COTTONWOOD #1		60.00	60.00	SSP SWP T	48.16		1
9	COTTONWOOD #2		60.00	60.00	SSP SWP T	23.63		1
10	RED BANK TAP		60.00	60.00	SWP SSP	0.68		1
11	COTTONWOOD	BENTON #1	60.00	60.00	SSP SWP T	15.53		1
12	COTTONWOOD	BENTON #2	60.00	60.00	OTHERS SSP	14.68		1
13	COTTONWOOD	RED BLUFF	60.00	60.00	OTHERS SSP	16.74		1
14	DEER CREEK	DRUM	60.00	60.00	SWP SSP	6.24		1
15	DEL MONTE	MONTEREY	60.00	60.00	SWP SSP	2.53		1
16	DEL MONTE	VIEJO	60.00	60.00	SWP SSP	7.92		1
17	NAVY LAB TAP		60.00	60.00	SWP	0.19		1
18	DESABLA	CENTERVILLE	60.00	60.00	SSP OTHERS	5.86		1
19	ORO FINO TAP		60.00	60.00	SWP SSP	1.30		1
20	FORKS OF THE BUTTE TAP		60.00	60.00	SWP	0.20		1
21	DIXON	VACA #1	60.00	60.00	SSP SWP T	18.35		1
22	TRAVIS TAP		60.00	60.00	SWP SSP	2.88		1
23	DIXON	VACA #2	60.00	60.00	SWP SSP	26.77		1
24	CACHE SLOUGH TAP		60.00	60.00	SWP SSP	6.85		1
25	DELTA	MTN GATE JCT	60.00	60.00	SSP OTHERS	15.14		1
26	LODI	INDUSTRIAL	60.00	60.00	SWP SSP	0.97		1
27	DRUM	GRASS VALLEY-WEIMAR	60.00	60.00	SWP SSP	31.17		1
28	CAPE HORN TAP		60.00	60.00	SWP	0.31		1
29	ROLLINS TAP		60.00	60.00	SWP SSP	0.73		1
30	DRUM	SPAULDING	60.00	60.00	SWP SSP	9.36		1
31	ESSEX JCT	ARCATA-FAIRHAVEN	60.00	60.00	SSP OTHERS	16.05		1
32	BLUE LAKE TAP		60.00	60.00	SWP SSP	3.70		1
33	BLUE CHIP MILLING TAP		60.00	60.00	SWP	0.42		1
34	ULTRA POWER TAP		60.00	60.00	SWP SSP	1.17		1
35	SIMPSON-KORBEL TAP		60.00	60.00	SWP	0.39		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	JANES CREEK TAP		60.00	60.00	SWP	1.78		1
2	ESSEX JCT	ORICK	60.00	60.00	OTHERS SSP	31.29		1
3	TRINIDAD TAP		60.00	60.00	SWP	1.34		1
4	EUREKA	STA A	60.00	60.00	SWP	0.22		1
5	ALMADEN	LOS GATOS	60.00	60.00	SWP SSP	6.38		1
6	EVERGREEN	ALMADEN	60.00	60.00	SWP	4.96		1
7	JEFFERSON #1		60.00	60.00	SWP T	9.05		1
8	EVERGREEN	MABURY	60.00	60.00	SWP	5.48		1
9	SENTER #1 TAP		60.00	60.00	SWP	0.23		1
10	JENNINGS TAP		60.00	60.00	SWP	0.14		1
11	FAIRHAVEN #1		60.00	60.00	SWP SSP	0.47		1
12	CLEAR LAKE	KONOCTI	60.00	60.00	OTHERS SSP	10.95		1
13	FAIRHAVEN POWER CO		60.00	60.00	SWP SSP	0.50		1
14	FAIRHAVEN	HUMBOLDT	60.00	60.00	SWP SSP	15.54		1
15	KONOCTI	EAGLE ROCK	60.00	60.00	OTHERS SSP	9.66		1
16	FRENCH MEADOWS	MIDDLE FORK	60.00	60.00	SWP SSP	13.19		1
17	FULTON	CALISTOGA	60.00	60.00	OTHERS SSP	64.61		1
18	FULTON	HOPLAND	60.00	60.00	SWP SSP	41.10		1
19	FITCH MTN #1 TAP		60.00	60.00	SWP SSP	0.86		1
20	HEALDSBURG #1 TAP		60.00	60.00	SWP SSP	0.25		1
21	WINDSOR	FITCH MOUNTAIN	60.00	60.00	SWP SSP	21.24		1
22	FITCH MTN #2 TAP		60.00	60.00	SWP	0.07		1
23	HEALDSBURG #2 TAP		60.00	60.00	SWP SSP	0.16		1
24	FULTON	MOLINO-COTATI	60.00	60.00	SWP SSP	20.52		1
25	FULTON	MOLINO-COTATI	60.00	60.00	SWP SSP	0.35		1
26	WASHOE TAP		60.00	60.00	SWP SSP	1.04		1
27	LAGUNA TAP		60.00	60.00	SWP SSP	1.68		1
28	GLENN #1		60.00	60.00	SWP SSP	33.37		1
29	ELK CREEK TAP		60.00	60.00	SWP SSP	20.44		1
30	GLENN #2		60.00	60.00	SWP SSP	34.69		1
31	GLENN #3		60.00	60.00	SWP SSP	28.51		1
32	HEADGATE TAP		60.00	60.00	SWP SSP	0.97		1
33	GOLD HILL #1		60.00	60.00	OTHERS SSP	27.85		1
34	GREEN VALLEY	WATSONVILLE	60.00	60.00	SWP SSP	4.74		1
35	CIC TAP		60.00	60.00	SWP	0.13		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	DEAN FOODS TAP		60.00	60.00	SWP	0.51		1
2	MONTE RIO	FORT ROSS	60.00	60.00	OTHERS SSP	14.30		1
3	FORT ROSS	GUALALA	60.00	60.00	OTHERS SSP	29.76		1
4	SALMON CREEK TAP		60.00	60.00	OTHERS SSP	10.51		1
5	HALSEY	PLACER	60.00	60.00	SWP SSP	4.94		1
6	MTN QUARRIES TAP		60.00	60.00	SWP SSP	2.63		1
7	AUBURN TAP		60.00	60.00	SWP SSP	0.75		1
8	HAMILTON BRANCH	CHESTER	60.00	60.00	OTHERS SSP	12.27		1
9	COLLINS PINE TAP		60.00	60.00	SWP	1.00		1
10	HAMMER	COUNTRY CLUB	60.00	60.00	SWP SSP	8.82		1
11	HAT CREEK #1	PIT #1	60.00	60.00	SSP OTHERS	6.08		1
12	HAT CREEK #1	WESTWOOD	60.00	60.00	OTHERS SSP	55.87		1
13	PIT #1	HAT CREEK #2-BURNEY	60.00	60.00	SWP SSP	12.96		1
14	BURNEY TAP		60.00	60.00	SWP SSP	1.09		1
15	HERDLYN	BALFOUR	60.00	60.00	SWP SSP	20.50		1
16	MIDDLE RIVER TAP		60.00	60.00	SWP SSP	7.02		1
17	MCDONALD TAP		60.00	60.00	OTHERS SSP	5.88		1
18	MARSH TAP		60.00	60.00	SWP	3.97		1
19	BRIONES TAP		60.00	60.00	SWP SSP	7.00		1
20	BIXLER TAP		60.00	60.00	SWP	0.55		1
21	HILLSDALE JCT	HALF MOON BAY	60.00	60.00	OTHERS SSP	6.82		1
22	HUMBOLDT BAY	EUREKA	60.00	60.00	SWP SSP	5.61		1
23	HUMBOLDT BAY	HUMBOLDT #1	60.00	60.00	SWP SSP	8.34		1
24	HUMBOLDT BAY	HUMBOLDT #2	60.00	60.00	SWP SSP	6.45		1
25	HUMBOLDT BAY	RIO DELL JCT	60.00	60.00	OTHERS SSP	18.40		1
26	EEL RIVER TAP		60.00	60.00	SSP SWP T	2.31		1
27	ARCATA	HUMBOLDT	60.00	60.00	SWP SSP	7.28		1
28	LP FLAKEBOARD TAP		60.00	60.00	SWP	0.51		1
29	HUMBOLDT #1		60.00	60.00	SSP SWP T	11.05		1
30	HUMBOLDT	EUREKA	60.00	60.00	SWP SSP	4.70		1
31	HUMBOLDT	MAPLE CREEK	60.00	60.00	OTHERS SSP	14.13		1
32	IGNACIO	BOLINAS #1	60.00	60.00	OTHERS SSP	15.06		1
33	IGNACIO	ALTO	60.00	60.00	SWP SSP	17.79		1
34	IGNACIO	ALTO-SAUSALITO #1	60.00	60.00	SSP SWP T	17.83		1
35	IGNACIO	ALTO-SAUSALITO #2	60.00	60.00	SWP SSP	17.83		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	IGNACIO	BOLINAS #2	60.00	60.00	OTHERS SSP	28.22		1
2	JEFFERSON	HILLSDALE JCT	60.00	60.00	SSP SWP T	14.72		1
3	WATERSHED TAP		60.00	60.00	SWP SSP	0.28		1
4	JEFFERSON	LAS PULGAS	60.00	60.00	SWP SSP	6.00		1
5	MARTIN	SNEATH LANE	60.00	60.00	SSP OTHERS	7.19		1
6	CRYSTAL SPRINGS TAP		60.00	60.00	SWP SSP	0.28		1
7	SNEATH LANE	HALF MOON BAY	60.00	60.00	OTHERS SSP	15.41		1
8	JEFFERSON	STANFORD	60.00	60.00	SWP SSP	7.64		1
9	SLAC TAP		60.00	60.00	SWP	1.41		1
10	KASSON #1		60.00	60.00	SWP SSP	0.19		1
11	KASSON	CARBONA	60.00	60.00	SWP SSP	7.32		1
12	LYOTH TAP		60.00	60.00	SWP	1.34		1
13	CARBONA #2 TAP		60.00	60.00	SWP	5.64		1
14	KASSON	BANTA #1	60.00	60.00	SWP	1.05		1
15	KASSON	LOUISE	60.00	60.00	SWP SSP	8.77		1
16	CALVO TAP		60.00	60.00	SWP	0.54		1
17	KESWICK	CASCADE	60.00	60.00	SWP SSP	9.36		1
18	KESWICK	TRINITY	60.00	60.00	OTHERS SSP	30.42		1
19	KILARC	CEDAR CREEK	60.00	60.00	SWP SSP	13.33		1
20	CLOVER CREEK TAP		60.00	60.00	SWP	0.02		1
21	KILARC	DESCHUTES	60.00	60.00	SWP SSP	27.29		1
22	KILARC	VOLTA TIE	60.00	60.00	T	1.93		1
23	KING CITY	COBURN #1	60.00	60.00	OTHERS SSP	21.91		1
24	JOLON TAP		60.00	60.00	SWP SSP	15.87		1
25	KING CITY	COBURN #2	60.00	60.00	OTHERS SSP	15.79		1
26	LOS COCHES TAP		60.00	60.00	SWP	1.33		1
27	LAKEVILLE #2		60.00	60.00	SSP SWP T	21.62		1
28	LAKEVILLE	PETALUMA C	60.00	60.00	SWP SSP	5.36		1
29	LAKEVILLE #1		60.00	60.00	OTHERS SSP	11.16		1
30	LAS POSITAS	VASCO	60.00	60.00	SWP SSP	1.50		1
31	LAURELES	OTTER	60.00	60.00	OTHERS SSP	15.56		1
32	LAYTONVILLE	COVELO	60.00	60.00	OTHERS SSP	16.09		1
33	LIVERMORE	LAS POSITAS	60.00	60.00	SWP SSP	3.63		1
34	LOCKEFORD	INDUSTRIAL	60.00	60.00	SWP	6.03		1
35	LOCKEFORD	LODI #2	60.00	60.00	SWP SSP	9.52		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	INDUSTRIAL TAP		60.00	60.00	SWP	0.97		1
2	VICTOR TAP		60.00	60.00	SSP	0.06		1
3	WOODBRIDGE TAP		60.00	60.00	SWP	0.53		1
4	LOCKEFORD	LODI #3	60.00	60.00	SWP SSP	15.42		1
5	MANTECA #1		60.00	60.00	SWP SSP	34.52		1
6	LEE TAP		60.00	60.00	SWP	5.85		1
7	MANTECA	LOUISE	60.00	60.00	SWP SSP	12.53		1
8	GRONEMEYER TAP		60.00	60.00	SWP	0.83		1
9	MAPLE CREEK	HOOPA	60.00	60.00	OTHERS SSP	29.13		1
10	MENDOCINO	HARTLEY	60.00	60.00	OTHERS SSP	23.17		1
11	HARTLEY	CLEARLAKE	60.00	60.00	SWP SSP	6.66		1
12	MENDOCINO	PHILO JCT-HOPLAND	60.00	60.00	SWP SSP	23.50		1
13	MENDOCINO #1		60.00	60.00	SWP SSP	7.48		1
14	MENDOCINO	WILLITS	60.00	60.00	OTHERS SSP	14.52		1
15	MENDOCINO	WILLITS-FORT BRAGG	60.00	60.00	OTHERS SSP	43.77		1
16	WEIMAR #1		60.00	60.00	OTHERS SSP	13.98		1
17	OXBOW TAP		60.00	60.00	SWP	0.15		1
18	MILLBRAE	SNEATH LANE	60.00	60.00	SSP SWP T	6.49		1
19	SAN ANDREAS (CCSF) TAP		60.00	60.00	SWP	0.39		1
20	SAN BRUNO TAP		60.00	60.00	SWP	1.13		1
21	SNEATH LANE	PACIFICA	60.00	60.00	OTHERS SSP	3.26		1
22	MONTA VISTA	BURNS	60.00	60.00	OTHERS SSP	18.06		1
23	MONTA VISTA	LOS ALTOS	60.00	60.00	SWP SSP	7.13		1
24	MONTA VISTA	LOS GATOS	60.00	60.00	SWP SSP	10.88		1
25	MONTA VISTA	PERMANENTE	60.00	60.00	SSP SWP T	1.19		1
26	PERMANENTE #1 TAP		60.00	60.00	SWP	0.31		1
27	PERMANENTE #2 TAP		60.00	60.00	SWP SSP	0.51		1
28	MONTE RIO	FULTON	60.00	60.00	OTHERS SSP	22.56		1
29	WOHLER TAP		60.00	60.00	SWP	1.44		1
30	MTN GATE JCT	CASCADE	60.00	60.00	OTHERS SSP	6.57		1
31	MTN GATE TAP		60.00	60.00	SWP	0.70		1
32	NEWARK	DECOTO	60.00	60.00	SSP SWP T	6.28		1
33	NEWARK	LIVERMORE	60.00	60.00	SSP OTHERS	19.05		1
34	NEWARK	VALLECITOS	60.00	60.00	SSP SWP T	12.39		1
35	SUNOL TAP		60.00	60.00	OTHERS SWP	0.08		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	NICOLAUS	CATLETT JCT	60.00	60.00	SSP SWP T	20.16		1
2	NICOLAUS	CATLETT JCT	60.00	60.00	SSP SWP T	4.45		1
3	NICOLAUS	CATLETT JCT (12KV)	60.00	60.00	SSP SWP T	14.18		1
4	NICOLAUS	MARYSVILLE	60.00	60.00	OTHERS SSP	18.74		1
5	NICOLAUS	PLAINFIELD	60.00	60.00	SSP SWP T	30.63		1
6	DISTRICT 1001 TAP		60.00	60.00	SWP	1.47		1
7	NICOLAUS	WILKINS SLOUGH	60.00	60.00	SSP OTHERS	42.72		1
8	DISTRICT 1500 TAP		60.00	60.00	SWP SSP	3.61		1
9	TOCALOMA TAP		60.00	60.00	OTHERS SWP	1.03		1
10	OILFIELDS	SARGENT CANYON	60.00	60.00	SWP	2.02		1
11	OILFIELDS	SALINAS RIVER	60.00	60.00	SWP	1.46		1
12	YUBA CITY COGEN TAP		60.00	60.00	SWP	0.80		1
13	PALERMO	OROVILLE #1	60.00	60.00	SWP SSP	6.97		1
14	PACIFIC OROVILLE POWER		60.00	60.00	SWP	0.78		1
15	LOUISIANA PACIFIC		60.00	60.00	SWP	0.16		1
16	PALERMO	OROVILLE #2	60.00	60.00	SWP SSP	10.13		1
17	ENCINAL TAP		60.00	60.00	SWP SSP	1.43		1
18	PEASE	HARTER	60.00	60.00	SWP SSP	15.88		1
19	GREENLEAF #2 TAP		60.00	60.00	SWP	0.62		1
20	PEASE	MARYSVILLE-HARTER	60.00	60.00	SWP SSP	10.31		1
21	PHILO JCT	ELK	60.00	60.00	OTHERS SSP	37.25		1
22	PIT #1	MCARTHUR	60.00	60.00	SWP SSP	7.30		1
23	PLACER	DEL MAR	60.00	60.00	SWP SSP	10.81		1
24	SIERRA PINES LIMITED		60.00	60.00	SWP	0.40		1
25	POTTER VALLEY	MENDOCINO	60.00	60.00	SWP SSP	10.94		1
26	POTTER VALLEY	WILLITS	60.00	60.00	OTHERS SSP	13.16		1
27	RADUM	LIVERMORE	60.00	60.00	SWP SSP	4.66		1
28	RIO DELL JCT	BRIDGEVILLE	60.00	60.00	OTHERS SSP	21.25		1
29	RIO DELL TAP		60.00	60.00	OTHERS SSP	5.36		1
30	PACIFIC LUMBER (SCOTIA)		60.00	60.00	OTHERS SWP	0.52		1
31	SALADO	CROW CREEK SW STA	60.00	60.00	SWP SSP	3.77		1
32	CROW CREEK SW STA	FRONTIER SOLAR PV	60.00	60.00	SSP	0.02		1
33	CROW CREEK SW STA	NEWMAN	60.00	60.00	SWP SSP	11.14		1
34	STANISLAUS RECOVERY		60.00	60.00	SWP	0.11		1
35	GUSTINE #1 TAP		60.00	60.00	SWP SSP	7.56		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	SALADO	NEWMAN #2	60.00	60.00	SWP SSP	21.56		1
2	CROWS LANDING TAP		60.00	60.00	SWP	5.28		1
3	GUSTINE #2 TAP		60.00	60.00	SWP	4.44		1
4	SALINAS	FORT ORD #1	60.00	60.00	SSP OTHERS	10.22		1
5	SALINAS	FIRESTONE #1	60.00	60.00	SWP SSP	6.15		1
6	FRESH EXPRESS TAP		60.00	60.00	SWP	0.56		1
7	SALINAS	FIRESTONE #2	60.00	60.00	SWP SSP	17.21		1
8	SALINAS	LAGUNITAS	60.00	60.00	SWP SSP	5.81		1
9	SALINAS	LAURELES	60.00	60.00	SWP SSP	27.46		1
10	SAN MATEO	BAIR	60.00	60.00	SSP T	13.99		1
11	SAN MATEO	HILLSDALE JCT	60.00	60.00	OTHERS SSP	6.89		1
12	SAN RAMON	RADUM	60.00	60.00	SWP	7.06		1
13	PARKS TAP		60.00	60.00	SWP	0.45		1
14	EAST DUBLIN (BART) TAP		60.00	60.00	SWP	0.04		1
15	SMARTVILLE	CAMP FAR WEST	60.00	60.00	SWP SSP	17.81		1
16	SMARTVILLE	CAMP FAR WEST (12KV)	60.00	60.00	SWP SSP	7.15		1
17	BEALE AFB (WAPA) #2 TAP		60.00	60.00	SWP SSP	0.14		1
18	SMARTVILLE	MARYSVILLE	60.00	60.00	SWP SSP	20.11		1
19	SMARTVILLE	NICOLAUS #1	60.00	60.00	OTHERS SSP	29.60		1
20	SMARTVILLE	NICOLAUS #2	60.00	60.00	OTHERS SSP	30.16		1
21	BEALE AFB (WAPA) #1 TAP		60.00	60.00	SSP	0.11		1
22	SOLEDAD #1		60.00	60.00	SWP SSP	15.50		1
23	GONZALES #1 TAP		60.00	60.00	SWP	0.20		1
24	CHUALAR TAP		60.00	60.00	SWP	1.43		1
25	SOLEDAD #2		60.00	60.00	SWP SSP	18.86		1
26	GONZALES #2 TAP		60.00	60.00	SWP SSP	0.30		1
27	SOLEDAD #3		60.00	60.00	SWP SSP	1.63		1
28	SOLEDAD #4		60.00	60.00	SWP SSP	6.08		1
29	SPAULDING #3	SPAULDING #1	60.00	60.00	SWP	1.09		1
30	SPAULDING	SUMMIT	60.00	60.00	SSP OTHERS	19.65		1
31	CISCO GROVE TAP		60.00	60.00	SWP	0.34		1
32	SUTTER HOME SW STA	LOCKEFORD-LODI	60.00	60.00	SWP SSP	29.77		1
33	SUTTER HOME	SUTTER HOME SW STA	60.00	60.00	SSP	0.03		1
34	SUTTER HOME SW STA	STAGG	60.00	60.00	SWP SSP	17.13		1
35	TERMINOUS TAP		60.00	60.00	SWP	3.01		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	SEBASTIANI TAP		60.00	60.00	SWP	0.01		1
2	STAGG	COUNTRY CLUB #1	60.00	60.00	SSP	2.43		1
3	STAGG	COUNTRY CLUB #2	60.00	60.00	SWP SSP	2.46		1
4	STAGG	HAMMER	60.00	60.00	SWP SSP	4.25		1
5	STOCKTON A #1		60.00	60.00	SSP SWP T	5.58		1
6	NEWARK-SIERRA		60.00	60.00	SWP	0.29		1
7	STOCKTON A	WEBER #1	60.00	60.00	SWP SSP	13.20		1
8	STOCKTON A	WEBER #2	60.00	60.00	SWP	9.87		1
9	STOCKTON A	WEBER #3	60.00	60.00	SWP SSP	9.81		1
10	SUMIDEN WIRE PRODUCTS		60.00	60.00	SWP	0.19		1
11	OAK PARK TAP		60.00	60.00	SWP SSP	0.87		1
12	STOCKTON	NEWARK	60.00	60.00	SSP SWP T	14.59		1
13	TRINITY	MAPLE CREEK	60.00	60.00	SSP OTHERS	55.45		1
14	TULUCAY	NAPA #1	60.00	60.00	SSP SWP T	9.72		1
15	BASALT #1 TAP		60.00	60.00	SWP T	1.18		1
16	CORDELIA #1 TAP		60.00	60.00	OTHERS SSP	7.69		1
17	CORDELIA INTERIM		60.00	60.00	SWP SSP	0.36		1
18	CORDELIA #2 TAP		60.00	60.00	OTHERS SSP	6.87		1
19	TULUCAY	NAPA #2	60.00	60.00	SWP SSP	3.93		1
20	VACA	PLAINFIELD	60.00	60.00	SWP SSP	29.83		1
21	VALLEY SPRINGS #1		60.00	60.00	OTHERS SSP	27.27		1
22	NEW HOGAN TAP		60.00	60.00	SWP	0.06		1
23	VALLEY SPRINGS	CALAVERAS CEMENT	60.00	60.00	SWP SSP	7.91		1
24	PARDEE #1 TAP		60.00	60.00	SWP	4.33		1
25	VALLEY SPRINGS	MARTELL #1	60.00	60.00	SWP SSP	12.75		1
26	AMFOR TAP		60.00	60.00	SWP	1.08		1
27	CLAY	MARTEL	60.00	60.00	OTHERS SSP	21.49		1
28	PARDEE #2 TAP		60.00	60.00	SWP	0.09		1
29	BUENA VISTA BIOMASS		60.00	60.00	SWP SSP	1.01		1
30	IONE TAP		60.00	60.00	SWP SSP	4.09		1
31	MULE CREEK TAP		60.00	60.00		0.01		1
32	VASCO	HERDLYN	60.00	60.00	OTHERS SSP	10.97		1
33	US WINDPOWER TAP		60.00	60.00	SWP	1.52		1
34	VALLEY SPRINGS	CLAY	60.00	60.00	OTHERS SSP	17.30		1
35	VIEJO	MONTEREY	60.00	60.00	SWP SSP	2.28		1
36					TOTAL	36,659.71		1,445

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	RADUM	VALLECITOS	60.00	60.00	SSP OTHERS	10.62		1
2	IUKA TAP		60.00	60.00	SWP	0.49		1
3	VOLTA	DESCHUTES	60.00	60.00	SWP SSP	20.86		1
4	VOLTA	SOUTH	60.00	60.00	SWP SSP	4.86		1
5	WATSONVILLE	SALINAS	60.00	60.00	OTHERS SSP	28.39		1
6	GRANITE ROCK TAP		60.00	60.00	SWP	2.39		1
7	LAGUNITAS TAP		60.00	60.00	SWP	0.60		1
8	WEBER	FRENCH CAMP #1	60.00	60.00	SWP SSP	6.07		1
9	WEBER	FRENCH CAMP #2	60.00	60.00	SSP SWP T	10.89		1
10	ROBERTSON TAP		60.00	60.00	SWP SSP	0.82		1
11	COGENERATION NATIONAL		60.00	60.00	SWP	0.56		1
12	ROUGH & READY TAP		60.00	60.00	SWP SSP	0.95		1
13	PACIFIC ETHANOL TAP		60.00	60.00	SWP	0.68		1
14	WEBER	MORMON JCT	60.00	60.00	SWP SSP	17.67		1
15	WEIMAR	HALSEY	60.00	60.00	SWP SSP	6.28		1
16	WEST POINT	VALLEY SPRINGS	60.00	60.00	OTHERS SSP	21.66		1
17	PINE GROVE TAP		60.00	60.00	SWP SSP	2.67		1
18	LAYTONVILLE	WILLITS	60.00	60.00	OTHERS SSP	23.14		1
19	GARBERVILLE	LAYTONVILLE	60.00	60.00	OTHERS SSP	39.99		1
20	WILLOW PASS	CONTRA COSTA	60.00	60.00	SSP SWP T	10.82		1
21	PITTSBURG #2 TAP		60.00	60.00	SWP	1.19		1
22	WIND FARMS		60.00	60.00	SWP	3.75		1
23	ZOND WIND TAP		60.00	60.00	SWP	1.19		1
24	COLUSA JCT #1		60.00	60.00	SWP SSP	16.98		1
25	DEL MONTE	FORT ORD #1	60.00	60.00	SWP SSP	6.13		1
26	MIDDLE FORK #1		60.00	60.00	OTHERS SSP	9.43		1
27	ELK	GUALALA	60.00	60.00	OTHERS SSP	29.01		1
28	GARCIA TAP		60.00	60.00	SWP SSP	3.04		1
29	CONTRA COSTA	BALFOUR	60.00	60.00	SWP SSP	11.55		1
30	DU PONT TAP		60.00	60.00	SWP	0.52		1
31	DEL MONTE	FORT ORD #2	60.00	60.00	SWP SSP	5.60		1
32	SALINAS	FORT ORD #2	60.00	60.00	SSP SWP T	10.12		1
33	GLENN #4		60.00	60.00	SWP SSP	12.54		1
34	TABLE MTN	PEACHTON	60.00	60.00	SWP SSP	14.84		1
35	PEACHTON	PEASE	60.00	60.00	SWP SSP	16.34		1
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	GLENN #5		60.00	60.00	SWP SSP	7.41		1
2	COLEMAN HATCHERY TAP		60.00	60.00	SWP SSP	0.56		1
3	VALLEY SPRINGS #2		60.00	60.00	OTHERS SSP	25.65		1
4	LOCKEFORD #1		60.00	60.00	OTHERS SSP	12.85		1
5	STANDARD #1 & #2 (12KV)		60.00	60.00	T	4.16		1
6	DEL MAR	ATLANTIC #1	60.00	60.00	N/A	1.18		1
7	COOLEY LANDING	STANFORD	60.00	60.00	N/A	1.59		1
8	JEFFERSON	STANFORD	60.00	60.00	N/A	1.52		1
9	JEFFERSON	LAS PULGAS	60.00	60.00	N/A	0.18		1
10	A	Y #1 (UNDERGROUND IDLE)			N/A	0.35		1
11								
12								
13								
14								
15								
16	Summary of lines							
17	listed individually above							
18	Towers & Poles		500.00			1,327.67		
19			230.00			5,334.06		
20			115.00			6,065.21		
21			70.00			1,544.85		
22			60.00			3,882.52		
23								
24	Other Underground							
25	Transmission Lines		230.00			86.41		
26			115.00			83.88		
27			70.00			0.39		
28			60.00			4.82		
29								
30	Transmission Roads							
31								
32								
33								
34								
35								
36					TOTAL	36,659.71		1,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	
2300 - AAC - BUND								1
2300 - AAC - BUND								2
2300 - AAC - BUND								3
2300 - AAC - BUND								4
2300 - AAC - BUND								5
2300 - AAC - BUND								6
2300 - AAC - BUND								7
2300 - AAC - BUND								8
2300 - AAC - BUND								9
2300 - AAC - BUND								10
2300 - AAC - BUND								11
2300 - AAC - BUND								12
2300 - AAC - BUND								13
2300 - AAC - BUND								14
2300 - AAC - BUND								15
2300 - AAC - BUND								16
2300 - AAC - BUND								17
2300 - AAC - BUND								18
2300 - AAC - BUND								19
2300 - AAC - BUND								20
2300 - AAC - BUND								21
795 - ACSR - SING								22
795 - ACSR - SING								23
795 - ACSR - SING								24
1113 - AAC - SING								25
954 - AAC - SINGL								26
1113 - AAC - BUND								27
1113 - ACSS - SIN								28
1113 - ACSS - SIN								29
2300 - AAC - SING								30
1113 - AAC - BUND								31
1113 - AAC - SING								32
954 - AAC - SINGL								33
1431 - AAC - SING								34
795 - ACSR - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1113 - AAC - SING								1
804.5 - ACSR - SI								2
954 - AAC - SINGL								3
795 - ACSR - SING								4
1431 - AAC - BUND								5
795 - ACSR - SING								6
954 - ACSR - SING								7
1431 - AAC - BUND								8
1113 - AAC - SING								9
1113 - AAC - SING								10
795 - ACSR - SING								11
795 - ACSR - SING								12
795 - ACSR - SING								13
795 - ACSR - SING								14
954 - ACSR - PARA								15
795 - ACSR - SING								16
1113 - ACSS - SIN								17
1113 - AAC - SING								18
1113 - AAC - SING								19
1113 - AAC - SING								20
954 - ACSS - SING								21
795 - ACSR - SING								22
1113 - ACSS - SIN								23
1113 - AAC - SING								24
795 - ACSR - SING								25
1113 - AAC - SING								26
954 - ACSS - SING								27
795 - ACSR - SING								28
643.7 - HOLO-CU -								29
643.7 - HOLO-CU -								30
954 - AAC - SINGL								31
1113 - AAC - SING								32
954 - AAC - SINGL								33
795 - ACSR - SING								34
1113 - AAC - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1113 - AAC - SING								1
1113 - AAC - SING								2
795 - ACSR - SING								3
1113 - AAC - BUND								4
954 - ACSS - SING								5
1113 - AAC - SING								6
643.7 - HOLO-CU -								7
2300 - AAC - SING								8
795 - ACSR - SING								9
1113 - ACSS - SIN								10
1113 - ACSS - SIN								11
795 - ACSR - SING								12
795 - ACSR - SING								13
1113 - AAC - SING								14
1113 - AAC - SING								15
1113 - AAC - BUND								16
1113 - AAC - SING								17
2300 - AAC - BUND								18
2300 - AAC - BUND								19
1431 - AAC - SING								20
1113 - AAC - SING								21
1431 - AAC - SING								22
1113 - AAC - SING								23
954 - AAC - SINGL								24
1113 - AAC - SING								25
1113 - AAC - SING								26
795 - ACSR - SING								27
1113 - AAC - BUND								28
1113 - AAC - BUND								29
954 - AAC - SINGL								30
1113 - ACSS - SIN								31
1272 - ACSR - BUN								32
1272 - ACSR - BUN								33
795 - ACSR - SING								34
795 - ACSR - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1431 - AAC - BUND								1
2300 - AAC - BUND								2
2300 - AAC - BUND								3
954 - ACSS - SING								4
1113 - AAC - SING								5
2300 - AAC - BUND								6
2300 - AAC - BUND								7
2300 - AAC - BUND								8
1113 - AAC - SING								9
795 - ACSR - SING								10
795 - ACSR - SING								11
1113 - ACSS - SIN								12
1113 - AAC - SING								13
1113 - AAC - SING								14
1113 - AAC - SING								15
795 - ACSR - SING								16
1113 - AAC - SING								17
795 - ACSR - SING								18
1113 - AAC - SING								19
1113 - AAC - SING								20
795 - ACSS - PARA								21
795 - ACSS - PARA								22
795 - ACSR - SING								23
2300 - AAC - BUND								24
2300 - AAC - BUND								25
2300 - AAC - BUND								26
1113 - AAC - BUND								27
1113 - AAC - BUND								28
795 - ACSR - SING								29
1113 - AAC - SING								30
1113 - AAC - SING								31
795 - ACSR - SING								32
1113 - AAC - BUND								33
1113 - AAC - SING								34
1113 - AAC - BUND								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1113 - AAC - SING								1
1113 - AAC - SING								2
1113 - AAC - SING								3
1113 - AAC - SING								4
1113 - AAC - SING								5
1431 - AAC - SING								6
1113 - AAC - SING								7
1113 - AAC - SING								8
1113 - AAC - SING								9
1113 - AAC - SING								10
2300 - AAC - BUND								11
954 - ACSS - SING								12
954 - ACSS - SING								13
1113 - AAC - SING								14
954 - ACSS - SING								15
954 - ACSS - SING								16
1113 - AAC - BUND								17
1113 - AAC - SING								18
954 - ACSR - SING								19
1113 - AAC - SING								20
954 - AAC - SINGL								21
1113 - AAC - SING								22
1113 - AAC - SING								23
1113 - AAC - SING								24
1113 - AAC - SING								25
795 - ACSR - SING								26
795 - ACSR - SING								27
1113 - AAC - BUND								28
795 - ACSR - PARA								29
1113 - AAC - BUND								30
795 - ACSS - SING								31
1113 - ACSS - SIN								32
1113 - ACSS - SIN								33
795 - ACSR - SING								34
795 - ACSR - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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)	
795 - ACSR - SING								1
518 - ACSR - SING								2
795 - ACSR - SING								3
795 - ACSR - SING								4
1113 - AAC - SING								5
795 - ACSR - SING								6
795 - ACSR - SING								7
795 - ACSR - SING								8
795 - ACSR - SING								9
795 - ACSR - SING								10
795 - ACSR - SING								11
795 - ACSR - SING								12
1113 - AAC - SING								13
954 - ACSS - SING								14
954 - ACSS - SING								15
1113 - AAC - SING								16
1113 - AAC - SING								17
1113 - AAC - SING								18
1431 - AAC - BUND								19
1113 - ACSS - SIN								20
1113 - AAC - SING								21
2300 - AAC - BUND								22
1431 - AAC - BUND								23
1431 - AAC - BUND								24
2300 - AAC - BUND								25
795 - ACSR - SING								26
2300 - AAC - SING								27
2300 - AAC - SING								28
1113 - AAC - BUND								29
1113 - AAC - SING								30
795 - ACSR - SING								31
1113 - AAC - SING								32
795 - ACSR - SING								33
795 - ACSR - SING								34
795 - ACSR - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
795 - ACSR - SING								1
1113 - AAC - SING								2
2300 - AAC - BUND								3
1113 - AAC - SING								4
795 - ACSS - SING								5
795 - ACSS - SING								6
954 - ACSS - SING								7
2300 - AAC - BUND								8
2300 - AAC - BUND								9
954 - ACSS - SING								10
954 - ACSS - SING								11
795 - ACSR - PARA								12
2300 - AAC - BUND								13
795 - ACSR - SING								14
1113 - AAC - SING								15
1113 - AAC - SING								16
954 - AAC - SINGL								17
1113 - ACSS - SIN								18
1113 - ACSS - SIN								19
1113 - ACSS - SIN								20
1113 - AAC - SING								21
1113 - ACSS - SIN								22
954 - AAC - SINGL								23
1113 - AAC - SING								24
1113 - AAC - SING								25
1431 - AAC - BUND								26
795 - ACSR - SING								27
795 - ACSS - SING								28
954 - ACSR - SING								29
954 - AAC - SINGL								30
1113 - AAC - SING								31
804.5 - ACSR - SI								32
1113 - AAC - SING								33
954 - ACSS - SING								34
954 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1113 - AAC - SING								1
954 - ACSS - SING								2
954 - ACSS - BUND								3
1113 - AAC - BUND								4
1113 - AAC - BUND								5
795 - ACSR - SING								6
1113 - ACSS - SIN								7
1113 - ACSS - SIN								8
1113 - AAC - SING								9
1431 - AAC - SING								10
954 - AAC - SINGL								11
1431 - AAC - SING								12
795 - ACSR - SING								13
2000 KCMIL - CU								14
2000 KCMIL - CU								15
2500 KCMIL - CU								16
2000 KCMIL - CU								17
2500 KCMIL - CU								18
2500 KCMIL - CU								19
2000 KCMIL - CU								20
								21
3500 KCMIL								22
2500 KCMIL - CU								23
2500 KCMIL - CU								24
1250 KCMIL -								25
3500 KCMIL -								26
3500 KCMIL -								27
1250 KCMIL -								28
477 - ACSS - SING								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
477 - ACSS - SING								1
715.5 - AAC - SIN								2
1113 - AAC - SING								3
477 - ACSS - SING								4
715.5 - AAC - SIN								5
397.5 - AAC - SIN								6
397.5 - ACSR - SI								7
								8
1113 - AAC - SING								9
715.5 - AAC - SIN								10
336.4 - AAC - SIN								11
3/0 - CU - SINGLE								12
3/0 - CU - SINGLE								13
1 - UNKNOWN -								14
1 - UNKNOWN -								15
4/0 - AAC - SINGL								16
2 - AAC - BUNDLE								17
2 - AAC - BUNDLE								18
2 - AAC - BUNDLE								19
2 - AAC - BUNDLE								20
477 - ACSS - SING								21
795 - ACSR - SING								22
4/0 - AAC - SINGL								23
715.5 - AAC - SIN								24
397.5 - AAC - SIN								25
336.4 - AAC - SIN								26
715.5 - AAC - SIN								27
								28
250 - CU - SINGLE								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
4/0 - AAC - SINGL								32
715.5 - AAC - SIN								33
4/0 - AAC - SINGL								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
250 - CU - PARALL								1
4/0 - AAC - SINGL								2
266.8 - AAC - SIN								3
250 - CU - SINGLE								4
4/0 - AAC - SINGL								5
715.5 - AAC - SIN								6
1113 - AAC - SING								7
4/0 - AAC - SINGL								8
1113 - AAC - SING								9
397.5 - ACSR - SI								10
4/0 - ACSR - SING								11
397.5 - AAC - SIN								12
250 - CU - SINGLE								13
477 - ACSS - SING								14
715.5 - AAC - SIN								15
397.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
397.5 - AAC - SIN								20
477 - ACSS - SING								21
397.5 - ACSR - SI								22
4/0 - ACSR - SING								23
397.5 - ACSR - SI								24
397.5 - ACSR - SI								25
								26
715.5 - AAC - SIN								27
266.8 - AAC - SIN								28
								29
397.5 - ACSR - SI								30
266.8 - AAC - SIN								31
397.5 - ACSR - SI								32
397.5 - ACSR - SI								33
397.5 - ACSR - SI								34
795 - ACSS - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
4/0 - AAC - SINGL								2
4/0 - AAC - SINGL								3
477 - ACSS - SING								4
477 - ACSS - BUND								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
1431 - AAC - SING								9
3/0 - CU-STEEL -								10
4/0 - AAC - SINGL								11
3/0 - CU-STEEL -								12
397.5 - AAC - SIN								13
1113 - AAC - SING								14
795 - ACSS - SING								15
715.5 - AAC - SIN								16
266.8 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
477 - ACSS - SING								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
397.5 - AAC - SIN								24
4/0 - AAC - SINGL								25
4/0 - CU - SINGLE								26
397.5 - AAC - SIN								27
477 - ACSS - SING								28
477 - ACSS - SING								29
715.5 - AAC - SIN								30
397.5 - ACSR - SI								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
3/0 - CU - PARALL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
4/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
2/0 - CU - SINGLE								6
715.5 - AAC - SIN								7
2/0 - CU - SINGLE								8
1113 - AAC - SING								9
1113 - AAC - SING								10
1113 - AAC - SING								11
1113 - AAC - SING								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
1113 - AAC - SING								15
4/0 - AAC - SINGL								16
2300 - AAC - UNKN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
1431 - AAC - SING								20
1113 - AAC - SING								21
397.5 - AAC - SIN								22
397.5 - ACSR - SI								23
336.4 - ACSR - SI								24
397.5 - ACSR - SI								25
397.5 - AAC - SIN								26
4/0 - AAC - SINGL								27
4/0 - AAC - SINGL								28
397.5 - ACSR - SI								29
397.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
715.5 - AAC - SIN								1
2300 - AAC - SING								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
266.8 - ACSR - PA								5
715.5 - AAC - SIN								6
266.8 - AAC - SIN								7
1113 - AAC - SING								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
266.8 - ACSR - PA								17
4/0 - AAC - SINGL								18
4/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
795 - ACSS - SING								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
266.8 - AAC - SIN								31
266.8 - AAC - SIN								32
4/0 - AAC - SINGL								33
397.5 - AAC - SIN								34
477 - ACSS - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
477 - ACSS - SING								1
715.5 - AAC - SIN								2
								3
477 - ACSS - SING								4
477 - ACSS - SING								5
715.5 - AAC - SIN								6
266.8 - AAC - SIN								7
397.5 - AAC - SIN								8
397.5 - AAC - SIN								9
397.5 - AAC - SIN								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
397.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - ALUM - SI								16
4/0 - AAC - SINGL								17
397.5 - AAC - SIN								18
715.5 - AAC - BUN								19
2/0 - CU - SINGLE								20
2/0 - CU - SINGLE								21
397.5 - AAC - SIN								22
1431 - AAC - SING								23
4/0 - AAC - SINGL								24
477 - ACSS - SING								25
4/0 - AAC - SINGL								26
4/0 - AAC - SINGL								27
397.5 - AAC - SIN								28
397.5 - AAC - SIN								29
397.5 - AAC - SIN								30
477 - ACSS - SING								31
477 - ACSS - SING								32
477 - ACSS - SING								33
397.5 - AAC - SIN								34
250 - CU - SINGLE								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
715.5 - AAC - SIN								2
397.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
1113 - AAC - SING								5
715.5 - AAC - SIN								6
4/0 - AAC - SINGL								7
715.5 - AAC - SIN								8
397.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
1113 - AAC - SING								12
477 - ACSS - SING								13
477 - ACSS - SING								14
1113 - AAC - SING								15
477 - ACSS - SING								16
715.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
477 - ACSS - SING								19
477 - ACSS - SING								20
795 - ACSS - SING								21
715.5 - AAC - SIN								22
397.5 - ACSR - SI								23
4/0 - ACSR - SING								24
397.5 - AAC - SIN								25
715.5 - AAC - SIN								26
397.5 - AAC - SIN								27
397.5 - AAC - SIN								28
4/0 - ACSR - SING								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
266.8 - AAC - SIN								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 - AAC - SIN								1
397.5 - AAC - SIN								2
715.5 - AAC - SIN								3
397.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
397.5 - AAC - SIN								7
477 - ACSS - SING								8
397.5 - AAC - SIN								9
477 - ACSS - SING								10
477 - ACSS - SING								11
397.5 - AAC - SIN								12
715.5 - AAC - SIN								13
795 - ACSS - SING								14
795 - ACSS - SING								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
397.5 - AAC - SIN								18
477 - ACSS - SING								19
715.5 - AAC - SIN								20
4/0 - AAC - SINGL								21
266.8 - AAC - SIN								22
4/0 - AAC - SINGL								23
4/0 - AAC - SINGL								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
250 - CU - SINGLE								27
336.4 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
477 - ACSS - SING								31
477 - ACSS - SING								32
336.4 - AAC - SIN								33
1113 - AAC - SING								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
715.5 - AAC - SIN								1
477 - ACSS - SING								2
715.5 - AAC - SIN								3
715.5 - AAC - PAR								4
715.5 - AAC - SIN								5
3/0 - CU - SINGLE								6
3/0 - CU - SINGLE								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
397.5 - AAC - SIN								17
2300 - AAC - SING								18
715.5 - AAC - SIN								19
2300 - AAC - SING								20
2300 - AAC - SING								21
1 - UNKNOWN -								22
2300 - AAC - SING								23
266.8 - AAC - SIN								24
2300 - AAC - SING								25
266.8 - AAC - SIN								26
477 - ACSS - SING								27
477 - ACSS - SING								28
2/0 - CU - SINGLE								29
2/0 - CU - SINGLE								30
715.5 - AAC - SIN								31
397.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
250 - CU - SINGLE								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
477 - ACSS - SING								1
397.5 - AAC - SIN								2
477 - ACSS - SING								3
477 - ACSS - SING								4
477 - ACSS - SING								5
477 - ACSS - SING								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
477 - ACSS - SING								11
397.5 - AAC - SIN								12
4/0 - AAC - SINGL								13
3/0 - CU - SINGLE								14
397.5 - AAC - SIN								15
1113 - AAC - SING								16
4/0 - CU - SINGLE								17
715.5 - AAC - SIN								18
665-T16 -								19
715.5 - AAC - SIN								20
665-T16 -								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
								25
1 - UNKNOWN -								26
397.5 - AAC - SIN								27
715.5 - AAC - SIN								28
2 - AAC - SINGLE								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
477 - ACSS - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	
397.5 - ACSR - SI								1
397.5 - ACSR - SI								2
397.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
477 - ACSS - SING								5
477 - ACSS - SING								6
477 - ACSS - SING								7
397.5 - AAC - SIN								8
477 - ACSS - SING								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
4/0 - AAC - SINGL								12
397.5 - ACSR - SI								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
4/0 - AAC - SINGL								20
4/0 - AAC - SINGL								21
715.5 - AAC - SIN								22
397.5 - AAC - SIN								23
477 - ACSS - SING								24
1 - UNKNOWN -								25
715.5 - AAC - BUN								26
1113 - AAC - BUND								27
1113 - AAC - BUND								28
715.5 - AAC - SIN								29
4/0 - AAC - SINGL								30
397.5 - AAC - SIN								31
2300 - AAC - BUND								32
2300 - AAC - BUND								33
715.5 - AAC - SIN								34
477 - ACSS - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
4/0 - AAC - SINGL								1
4/0 - AAC - SINGL								2
477 - ACSS - SING								3
4/0 - AAC - SINGL								4
397.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
477 - ACSS - SING								7
477 - ACSS - SING								8
715.5 - AAC - SIN								9
2/0 - CU - SINGLE								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
250 - CU - SINGLE								16
266.8 - AAC - SIN								17
477 - ACSS - SING								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
397.5 - AAC - SIN								21
397.5 - AAC - SIN								22
4/0 - CU - SINGLE								23
397.5 - ACSR - SI								24
1113 - AAC - SING								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
336.4 - AAC - SIN								29
4/0 - CU - SINGLE								30
4/0 - CU - SINGLE								31
715.5 - AAC - SIN								32
477 - ACSS - SING								33
397.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
397.5 - AAC - SIN								2
397.5 - AAC - SIN								3
266.8 - AAC - SIN								4
266.8 - AAC - SIN								5
4/0 - AAC - SINGL								6
477 - ACSS - SING								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - CU - SINGLE								10
397.5 - AAC - SIN								11
266.8 - AAC - SIN								12
397.5 - AAC - SIN								13
266.8 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - PAR								17
3/0 - CU - PARALL								18
954 - ACSR - PARA								19
397.5 - ACSR - SI								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
397.5 - AAC - SIN								28
2/0 - CU - SINGLE								29
2/0 - CU - SINGLE								30
2/0 - CU - SINGLE								31
2/0 - CU - SINGLE								32
2/0 - CU - SINGLE								33
715.5 - AAC - SIN								34
2/0 - CU - SINGLE								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2/0 - CU - SINGLE								1
2/0 - CU - SINGLE								2
477 - ACSS - SING								3
715.5 - AAC - SIN								4
266.8 - AAC - SIN								5
397.5 - AAC - SIN								6
477 - ACSS - SING								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
336.4 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
477 - ACSS - SING								18
715.5 - AAC - SIN								19
2/0 - CU - SINGLE								20
4/0 - AAC - SINGL								21
								22
477 - ACSS - SING								23
715.5 - AAC - SIN								24
2/0 - CU - SINGLE								25
954 - ACSS - SING								26
397.5 - ACSR - SI								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
1113 - AAC - SING								33
4/0 - AAC - SINGL								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1 - UNKNOWN -								1
715.5 - AAC - BUN								2
336.4 - ACSR - SI								3
397.5 - ACSR - SI								4
715.5 - AAC - SIN								5
250 - CU - SINGLE								6
715.5 - AAC - SIN								7
2/0 - CU - SINGLE								8
397.5 - ACSR - UN								9
477 - ACSS - SING								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
477 - ACSS - SING								15
715.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
266.8 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
4/0 - AAC - SINGL								27
715.5 - AAC - SIN								28
4/0 - ACSR - SING								29
397.5 - ACSR - SI								30
4/0 - ACSR - SING								31
715.5 - AAC - SIN								32
1113 - AAC - SING								33
250 - CU - SINGLE								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4/0 - AAC - SINGL								1
397.5 - AAC - SIN								2
477 - ACSS - SING								3
477 - ACSS - SING								4
477 - ACSS - SING								5
477 - ACSS - SING								6
715.5 - AAC - SIN								7
250 - CU - SINGLE								8
397.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
1 - UNKNOWN -								12
477 - ACSS - SING								13
1113 - AAC - SING								14
715.5 - AAC - SIN								15
397.5 - ACSR - SI								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
477 - ACSS - SING								19
250 - CU - SINGLE								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
397.5 - AAC - SIN								23
397.5 - AAC - SIN								24
715.5 - AAC - SIN								25
4/0 - AAC - SINGL								26
477 - ACSS - SING								27
477 - ACSS - SING								28
397.5 - AAC - SIN								29
4/0 - AAC - SINGL								30
250 - CU - SINGLE								31
266.8 - AAC - SIN								32
1113 - AAC - SING								33
1113 - AAC - SING								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
715.5 - AAC - SIN								1
477 - ACSS - SING								2
3500 KCMIL - CU								3
3500 KCMIL - CU								4
2500 KCMIL - CU								5
3500 KCMIL - CU								6
1250 KCMIL - CU								7
1250 KCMIL								8
1250 KCMIL - CU								9
3000 KCMIL -								10
1000 KCMIL - CU								11
1250 KCMIL								12
1250 KCMIL - CU								13
1250 KCMIL - CU								14
1000 KCMIL - CU								15
1000 KCMIL - CU								16
1250 KCMIL - CU								17
3000 KCMIL								18
1250 KCMIL - CU								19
3000 KCMIL								20
3000 KCMIL -								21
								22
2000 KCMIL - CU								23
3000 KCMIL - CU								24
500 KCMIL								25
3000 KCMIL -								26
3000 KCMIL -								27
3000 KCMIL -								28
3000 KCMIL -								29
3000 KCMIL -								30
3000 KCMIL -								31
								32
								33
2500 KCMIL - CU								34
2500 KCMIL - CU								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
CU								1
CU								2
3000 KCMIL - CU								3
3000 KCMIL - CU								4
1113 - AAC - SING								5
715.5 - AAC - SIN								6
397.5 - ALUM - SI								7
715.5 - AAC - SIN								8
397.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
4/0 - AAC - SINGL								12
4/0 - AAC - SINGL								13
1/0 - ACSR - SING								14
1/0 - ACSR - SING								15
3/0 - AAC - SINGL								16
1/0 - ACSR - SING								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
397.5 - AAC - SIN								20
3/0 - AAC - SINGL								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
1 - UNKNOWN -								30
397.5 - AAC - SIN								31
307.1 - AAC - SIN								32
1113 - AAC - SING								33
715.5 - AAC - SIN								34
1/0 - ACSR - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 - AAC - SIN								1
4/0 - AAC - SINGL								2
715.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
715.5 - AAC - SIN								5
4/0 - CU - SINGLE								6
4/0 - ACSR - SING								7
715.5 - AAC - SIN								8
3/0 - AAC - SINGL								9
266.8 - AAC - SIN								10
715.5 - AAC - SIN								11
397.5 - AAC - SIN								12
715.5 - AAC - SIN								13
3/0 - ACSR - SING								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
266.8 - AAC - SIN								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
4/0 - AAC - SINGL								22
715.5 - AAC - SIN								23
397.5 - AAC - SIN								24
4/0 - AAC - SINGL								25
715.5 - AAC - SIN								26
266.8 - AAC - SIN								27
1/0 - ACSR - SING								28
4/0 - AAC - SINGL								29
397.5 - AAC - SIN								30
4/0 - ACSR - SING								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
715.5 - AAC - SIN								1
4/0 - AAC - SINGL								2
477 - ACSS - SING								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
266.8 - AAC - SIN								8
4/0 - AAC - SINGL								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
715.5 - AAC - SIN								13
397.5 - AAC - SIN								14
266.8 - AAC - SIN								15
4/0 - AAC - SINGL								16
715.5 - AAC - SIN								17
4/0 - CU - SINGLE								18
1/0 - ACSR - SING								19
477 - ACSS - SING								20
4/0 - CU - SINGLE								21
4/0 - AAC - SINGL								22
266.8 - AAC - SIN								23
266.8 - AAC - SIN								24
715.5 - AAC - SIN								25
795 - ACSR - SING								26
715.5 - AAC - SIN								27
4/0 - AAC - SINGL								28
2 - ACSR - SINGLE								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
2/0 - CU - SINGLE								32
2/0 - CU - SINGLE								33
715.5 - AAC - SIN								34
4/0 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4/0 - AAC - SINGL								1
4/0 - AAC - SINGL								2
266.8 - AAC - SIN								3
397.5 - AAC - SIN								4
1/0 - ACSR - SING								5
2 - ACSR - SINGLE								6
1113 - AAC - SING								7
4/0 - AAC - SINGL								8
4/0 - AAC - SINGL								9
2 - UNKNOWN -								10
715.5 - AAC - SIN								11
397.5 - AAC - SIN								12
266.8 - AAC - SIN								13
2 - CU - SINGLE 1								14
715.5 - AAC - SIN								15
397.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
4/0 - AAC - SINGL								22
4/0 - AAC - SINGL								23
266.8 - AAC - SIN								24
266.8 - AAC - SIN								25
266.8 - AAC - SIN								26
715.5 - AAC - SIN								27
1113 - AAC - SING								28
1/0 - CU - SINGLE								29
250 - CU - SINGLE								30
266.8 - AAC - SIN								31
715.5 - AAC - SIN								32
2 - ACSR - SINGLE								33
4 - CU - SINGLE 4								34
4/0 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
397.5 - AAC - SIN								3
397.5 - AAC - SIN								4
715.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
4/0 - AAC - SINGL								7
1/0 - ACSR - SING								8
2 - ACSR - SINGLE								9
397.5 - AAC - SIN								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
4/0 - AAC - SINGL								13
715.5 - AAC - SIN								14
4/0 - AAC - SINGL								15
2 - ACSR - SINGLE								16
397.5 - ACSR - SI								17
715.5 - AAC - SIN								18
1/0 - ACSR - SING								19
715.5 - AAC - SIN								20
336.4 - AAC - SIN								21
1/0 - ACSR - SING								22
1 - CU - SINGLE								23
397.5 - AAC - SIN								24
715.5 - AAC - SIN								25
4/0 - AAC - SINGL								26
2 - CU - SINGLE								27
397.5 - AAC - SIN								28
266.8 - AAC - SIN								29
1113 - AAC - SING								30
1113 - AAC - SING								31
4/0 - AAC - SINGL								32
1113 - AAC - SING								33
1113 - AAC - SING								34
1750 KCMIL -								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
477 - ACSS - SING								1
715.5 - AAC - SIN								2
477 - ACSS - SING								3
397.5 - AAC - SIN								4
								5
2/0 - CU - SINGLE								6
2/0 - CU - SINGLE								7
715.5 - AAC - SIN								8
477 - ACSS - SING								9
715.5 - AAC - SIN								10
397.5 - AAC - SIN								11
4/0 - AAC - SINGL								12
4/0 - AAC - SINGL								13
4/0 - ACSR - SING								14
4/0 - AAC - SINGL								15
								16
2/0 - CU - SINGLE								17
1/0 - ACSR - SING								18
397.5 - AAC - SIN								19
4/0 - AAC - SINGL								20
397.5 - AAC - SIN								21
397.5 - ACSR - SI								22
397.5 - ACSR - SI								23
397.5 - ACSR - SI								24
								25
795 - ACSR - SING								26
397.5 - AAC - SIN								27
1/0 - ACSR - SING								28
715.5 - AAC - SIN								29
2/0 - CU - SINGLE								30
1 - UNKNOWN -								31
336.4 - AAC - SIN								32
715.5 - AAC - SIN								33
336.4 - AAC - SIN								34
4/0 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
4/0 - AAC - SINGL								1
2 - CU - SINGLE 3								2
2 - CU - SINGLE 3								3
397.5 - AAC - SIN								4
4/0 - AAC - SINGL								5
4/0 - AAC - SINGL								6
4/0 - AAC - SINGL								7
1431 - AAC - BUND								8
715.5 - AAC - SIN								9
397.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
1 - CU - SINGLE 2								14
715.5 - AAC - SIN								15
1113 - AAC - BUND								16
2 - CU - SINGLE 2								17
4 - CU - SINGLE 2								18
2/0 - CU - SINGLE								19
2/0 - CU - SINGLE								20
477 - ACSS - SING								21
2/0 - CU - SINGLE								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
397.5 - AAC - SIN								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
4/0 - CU - SINGLE								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
250 - CU - SINGLE								33
715.5 - AAC - SIN								34
715.5 - AAC - BUN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
715.5 - AAC - SIN								1
1/0 - ACSR - SING								2
2/0 - CU - SINGLE								3
715.5 - AAC - SIN								4
2/0 - CU - SINGLE								5
4/0 - AAC - SINGL								6
2/0 - CU - SINGLE								7
2/0 - CU - SINGLE								8
4/0 - AAC - SINGL								9
1/0 - ACSR - SING								10
2/0 - CU - SINGLE								11
250 - CU - SINGLE								12
2/0 - CU - SINGLE								13
2/0 - CU - SINGLE								14
715.5 - AAC - SIN								15
266.8 - AAC - BUN								16
2 - CU - SINGLE								17
350 - AAC - SINGL								18
2 - ACSR - SINGLE								19
350 - AAC - SINGL								20
2/0 - CU - SINGLE								21
715.5 - AAC - SIN								22
2/0 - CU - SINGLE								23
4/0 - AAC - SINGL								24
2/0 - CU - SINGLE								25
715.5 - AAC - SIN								26
397.5 - ACSR - SI								27
2 - ACSR - SINGLE								28
4/0 - ACSR - SING								29
336.4 - AAC - SIN								30
2/0 - CU - SINGLE								31
4/0 - ACAR - SING								32
4/0 - AAC - SINGL								33
4/0 - AAC - SINGL								34
4/0 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4/0 - AAC - SINGL								1
2/0 - CU - SINGLE								2
1 - CU - SINGLE								3
2/0 - CU - SINGLE								4
336.4 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
336.4 - AAC - SIN								8
336.4 - AAC - SIN								9
336.4 - AAC - SIN								10
397.5 - AAC - SIN								11
715.5 - AAC - SIN								12
397.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
4/0 - ACSR - SING								16
4/0 - AAC - SINGL								17
2/0 - CU - SINGLE								18
477 - ACSS - SING								19
4/0 - AAC - SINGL								20
477 - ACSS - SING								21
2/0 - CU - SINGLE								22
4/0 - AAC - SINGL								23
1 - UNKNOWN -								24
1 - UNKNOWN -								25
4/0 - AAC - SINGL								26
4/0 - AAC - SINGL								27
2/0 - CU - SINGLE								28
2 - CU - SINGLE 2								29
2/0 - CU - SINGLE								30
1 - CU - SINGLE 2								31
4/0 - AAC - SINGL								32
2/0 - CU - SINGLE								33
397.5 - AAC - SIN								34
397.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
397.5 - AAC - SIN								4
397.5 - AAC - SIN								5
397.5 - AAC - SIN								6
2/0 - CU - SINGLE								7
2/0 - CU - SINGLE								8
2 - ACSR - SINGLE								9
715.5 - AAC - SIN								10
4 - CU - SINGLE 3								11
4/0 - CU - SINGLE								12
397.5 - AAC - SIN								13
1/0 - ACSR - SING								14
1 - CU - SINGLE 4								15
397.5 - AAC - SIN								16
1/0 - ACSR - SING								17
1/0 - ACSR - SING								18
4/0 - AAC - SINGL								19
4/0 - AAC - SINGL								20
397.5 - AAC - SIN								21
2/0 - CU - SINGLE								22
2/0 - CU - SINGLE								23
1113 - AAC - SING								24
4/0 - AAC - SINGL								25
4/0 - AAC - SINGL								26
715.5 - AAC - SIN								27
397.5 - AAC - SIN								28
715.5 - AAC - SIN								29
2/0 - CU - SINGLE								30
2/0 - CU - SINGLE								31
397.5 - AAC - SIN								32
397.5 - AAC - SIN								33
477 - ACSS - SING								34
477 - ACSS - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
715.5 - AAC - PAR								2
4/0 - AAC - SINGL								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
397.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
4/0 - AAC - SINGL								12
397.5 - AAC - SIN								13
715.5 - AAC - SIN								14
2/0 - CU - SINGLE								15
2 - CU - SINGLE 2								16
4/0 - AAC - SINGL								17
2/0 - CU - SINGLE								18
2 - CU - SINGLE 1								19
								20
397.5 - AAC - SIN								21
1/0 - ACSR - SING								22
397.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
2/0 - CU - SINGLE								25
4/0 - AAC - SINGL								26
2/0 - CU - SINGLE								27
250 - CU - SINGLE								28
397.5 - AAC - SIN								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
715.5 - AAC - SIN								1
4/0 - AAC - SINGL								2
4/0 - AAC - SINGL								3
2/0 - CU - SINGLE								4
1/0 - AAC - UNKNO								5
4/0 - AAC - SINGL								6
2/0 - CU - SINGLE								7
2/0 - CU - SINGLE								8
4/0 - ACAR - SING								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
266.8 - AAC - SIN								12
2/0 - CU - SINGLE								13
2/0 - CU - SINGLE								14
715.5 - ALUM - SI								15
715.5 - AAC - SIN								16
4/0 - ACSR - SING								17
715.5 - AAC - PAR								18
397.5 - AAC - SIN								19
1/0 - ACSR - SING								20
715.5 - AAC - SIN								21
397.5 - AAC - SIN								22
336.4 - AAC - SIN								23
715.5 - AAC - SIN								24
397.5 - AAC - SIN								25
397.5 - AAC - SIN								26
397.5 - AAC - SIN								27
2/0 - CU - SINGLE								28
2 - ACSR - SINGLE								29
2/0 - CU - SINGLE								30
1/0 - ACSR - SING								31
2/0 - CU - SINGLE								32
336.4 - AAC - SIN								33
2/0 - CU - SINGLE								34
4/0 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2/0 - CU - SINGLE								1
2/0 - CU - SINGLE								2
2/0 - CU - SINGLE								3
4/0 - AAC - SINGL								4
2/0 - CU - SINGLE								5
4 - CU - SINGLE								6
2/0 - CU - SINGLE								7
4/0 - AAC - SINGL								8
2 - ACSR - SINGLE								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
477 - ACSS - SING								12
2/0 - CU - SINGLE								13
4/0 - AAC - SINGL								14
1/0 - ACSR - SING								15
715.5 - AAC - SIN								16
4 - CU - SINGLE								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
397.5 - AAC - SIN								21
1/0 - ACSR - SING								22
715.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
266.8 - AAC - SIN								25
1/0 - ACSR - SING								26
715.5 - AAC - SIN								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
4/0 - AAC - SINGL								30
266.8 - AAC - SIN								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
397.5 - AAC - SIN								34
4/0 - AAC - SINGL								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
715.5 - AAC - SIN								1
266.8 - AAC - SIN								2
2/0 - CU - SINGLE								3
2/0 - CU - SINGLE								4
2/0 - CU - SINGLE								5
2/0 - CU - SINGLE								6
2/0 - CU - SINGLE								7
2/0 - CU - SINGLE								8
266.8 - AAC - SIN								9
4/0 - CU - SINGLE								10
397.5 - AAC - SIN								11
715.5 - AAC - SIN								12
4 - CU - SINGLE 1								13
715.5 - AAC - SIN								14
2/0 - CU - SINGLE								15
2/0 - CU - SINGLE								16
2/0 - CU - SINGLE								17
266.8 - AAC - SIN								18
2/0 - CU - SINGLE								19
715.5 - AAC - SIN								20
2/0 - CU - SINGLE								21
2/0 - CU - SINGLE								22
2/0 - CU - SINGLE								23
2/0 - CU - SINGLE								24
4/0 - AAC - SINGL								25
2/0 - CU - SINGLE								26
397.5 - AAC - SIN								27
397.5 - AAC - SIN								28
1/0 - CU - SINGLE								29
336.4 - AAC - SIN								30
2 - ACSR - SINGLE								31
2/0 - CU - SINGLE								32
715.5 - AAC - SIN								33
266.8 - AAC - SIN								34
2/0 - ACSR - SING								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
266.8 - AAC - SIN								5
715.5 - AAC - SIN								6
2/0 - CU - SINGLE								7
715.5 - AAC - SIN								8
2/0 - CU - SINGLE								9
397.5 - AAC - SIN								10
4 - CU - SINGLE								11
397.5 - AAC - SIN								12
336.4 - ACSR - SI								13
715.5 - AAC - SIN								14
477 - ACSS - SING								15
1 - CU - SINGLE 4								16
1/0 - ACSR - SING								17
2/0 - CU - SINGLE								18
715.5 - AAC - SIN								19
266.8 - AAC - SIN								20
1113 - AAC - SING								21
1/0 - ACSR - SING								22
715.5 - AAC - SIN								23
2/0 - CU - SINGLE								24
2/0 - CU - SINGLE								25
4/0 - AAC - SINGL								26
4/0 - AAC - SINGL								27
2/0 - CU - SINGLE								28
715.5 - AAC - SIN								29
4/0 - AAC - SINGL								30
4/0 - AAC - SINGL								31
397.5 - AAC - SIN								32
4/0 - AAC - SINGL								33
2/0 - CU - SINGLE								34
715.5 - AAC - SIN								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2/0 - CU - SINGLE								1
4 - CU - SINGLE								2
4/0 - AAC - SINGL								3
2/0 - CU - SINGLE								4
2/0 - CU - SINGLE								5
4/0 - AAC - SINGL								6
								7
715.5 - AAC - SIN								8
2/0 - CU - SINGLE								9
397.5 - AAC - SIN								10
715.5 - AAC - SIN								11
397.5 - AAC - SIN								12
715.5 - AAC - SIN								13
471 - AAC - SINGL								14
397.5 - AAC - SIN								15
266.8 - ACAR - SI								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
3/0 - CU - SINGLE								21
715.5 - AAC - SIN								22
								23
2/0 - CU - SINGLE								24
2/0 - CU - SINGLE								25
4/0 - ACSR - SING								26
397.5 - AAC - SIN								27
1/0 - ACSR - SING								28
397.5 - AAC - SIN								29
715.5 - AAC - SIN								30
2/0 - CU - SINGLE								31
2/0 - CU - SINGLE								32
2/0 - CU - SINGLE								33
4/0 - AAC - SINGL								34
2/0 - CU - SINGLE								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4/0 - AAC - SINGL								1
4/0 - AAC - SINGL								2
1 - CU - SINGLE 2								3
2/0 - CU - SINGLE								4
1 - UNKNOWN -								5
3000 KCMIL - CU								6
2000 KCMIL -								7
UNKNOWN -								8
1750 KCMIL -								9
1250 KCMIL - CU								10
								11
								12
								13
								14
								15
								16
								17
	26,319,090	507,383,581	533,702,671	7,150,297	44,573,488		51,723,785	18
	70,158,258	1,969,322,958	2,039,481,216	28,727,164	179,079,270		207,806,434	19
	83,405,335	1,226,455,224	1,309,860,559	32,664,845	203,625,971		236,290,816	20
	13,357,405	264,391,752	277,749,157	8,319,963	51,864,953		60,184,916	21
	31,209,635	630,194,010	661,403,645	20,909,755	130,347,143		151,256,898	22
								23
								24
	2,790,742	238,509,403	241,300,145	145,119	881,644		1,026,763	25
	110,046	568,416,466	568,526,512	140,878	855,877		996,755	26
								27
		23,275,140	23,275,140	8,751	53,165		61,916	28
								29
		119,556,851	119,556,851					30
								31
								32
								33
								34
								35
	227,350,511	5,547,505,385	5,774,855,896	98,066,772	611,281,511		709,348,283	36

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 03/25/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: a
Bundle
Schedule Page: 422 Line No.: 1 Column: e
SSP - Single Steel Poles; SWP - Single Wood Poles; WH - Wood "H" Structures; T - Steel Towers; UG - Underground
Schedule Page: 422 Line No.: 2 Column: a
Bundle
Schedule Page: 422 Line No.: 3 Column: a
Bundle
Schedule Page: 422 Line No.: 4 Column: a
Bundle
Schedule Page: 422 Line No.: 5 Column: a
Bundle
Schedule Page: 422 Line No.: 6 Column: a
Bundle
Schedule Page: 422 Line No.: 7 Column: a
Bundle
Schedule Page: 422 Line No.: 8 Column: a
Bundle
Schedule Page: 422 Line No.: 9 Column: a
Bundle
Schedule Page: 422 Line No.: 10 Column: a
Bundle
Schedule Page: 422 Line No.: 11 Column: a
Bundle
Schedule Page: 422 Line No.: 12 Column: a
Bundle
Schedule Page: 422 Line No.: 13 Column: a
Bundle
Schedule Page: 422 Line No.: 14 Column: a
Bundle
Schedule Page: 422 Line No.: 15 Column: a
Bundle
Schedule Page: 422 Line No.: 16 Column: a
Bundle
Schedule Page: 422 Line No.: 17 Column: a
Bundle
Schedule Page: 422 Line No.: 18 Column: a
Bundle
Schedule Page: 422 Line No.: 19 Column: a
Bundle
Schedule Page: 422 Line No.: 20 Column: a
Bundle
Schedule Page: 422 Line No.: 21 Column: a
Bundle
Schedule Page: 422 Line No.: 24 Column: a
Bundle
Schedule Page: 422 Line No.: 27 Column: a
Bundle
Schedule Page: 422 Line No.: 30 Column: a
Idle
Schedule Page: 422 Line No.: 31 Column: a
Bundle

Schedule Page: 422.1 Line No.: 2 Column: a
Bundle
Schedule Page: 422.1 Line No.: 5 Column: a
Bundle
Schedule Page: 422.1 Line No.: 8 Column: a
Bundle
Schedule Page: 422.1 Line No.: 9 Column: a
Bundle
Schedule Page: 422.2 Line No.: 4 Column: a
Bundle
Schedule Page: 422.2 Line No.: 14 Column: a
Bundle
Schedule Page: 422.2 Line No.: 16 Column: a
Bundle
Schedule Page: 422.2 Line No.: 18 Column: a
Bundle
Schedule Page: 422.2 Line No.: 19 Column: a
Bundle, Idle
Schedule Page: 422.2 Line No.: 27 Column: a
Bundle
Schedule Page: 422.2 Line No.: 28 Column: a
Bundle
Schedule Page: 422.2 Line No.: 29 Column: a
Bundle
Schedule Page: 422.2 Line No.: 32 Column: a
Bundle
Schedule Page: 422.2 Line No.: 33 Column: a
Bundle
Schedule Page: 422.3 Line No.: 1 Column: a
Bundle
Schedule Page: 422.3 Line No.: 2 Column: a
Bundle
Schedule Page: 422.3 Line No.: 3 Column: a
Bundle
Schedule Page: 422.3 Line No.: 6 Column: a
Bundle
Schedule Page: 422.3 Line No.: 7 Column: a
Bundle
Schedule Page: 422.3 Line No.: 8 Column: a
Bundle
Schedule Page: 422.3 Line No.: 21 Column: a
Bundle
Schedule Page: 422.3 Line No.: 22 Column: a
Bundle
Schedule Page: 422.3 Line No.: 24 Column: a
Bundle
Schedule Page: 422.3 Line No.: 25 Column: a
Bundle
Schedule Page: 422.3 Line No.: 26 Column: a
Bundle
Schedule Page: 422.3 Line No.: 27 Column: a
Bundle
Schedule Page: 422.3 Line No.: 28 Column: a
Bundle

Schedule Page: 422.3 Line No.: 30 Column: a
Bundle

Schedule Page: 422.3 Line No.: 33 Column: a
Bundle

Schedule Page: 422.3 Line No.: 35 Column: a
Bundle

Schedule Page: 422.4 Line No.: 6 Column: a
Bundle

Schedule Page: 422.4 Line No.: 11 Column: a
Bundle

Schedule Page: 422.4 Line No.: 14 Column: a
Bundle

Schedule Page: 422.4 Line No.: 17 Column: a
Bundle

Schedule Page: 422.4 Line No.: 28 Column: a
Bundle

Schedule Page: 422.4 Line No.: 29 Column: a
Bundle

Schedule Page: 422.4 Line No.: 30 Column: a
Bundle

Schedule Page: 422.5 Line No.: 19 Column: a
Bundle

Schedule Page: 422.5 Line No.: 22 Column: a
Bundle

Schedule Page: 422.5 Line No.: 23 Column: a
Bundle

Schedule Page: 422.5 Line No.: 24 Column: a
Bundle

Schedule Page: 422.5 Line No.: 25 Column: a
Bundle

Schedule Page: 422.5 Line No.: 29 Column: a
Bundle

Schedule Page: 422.6 Line No.: 3 Column: a
Bundle

Schedule Page: 422.6 Line No.: 8 Column: a
Bundle

Schedule Page: 422.6 Line No.: 9 Column: a
Bundle

Schedule Page: 422.6 Line No.: 12 Column: a
Bundle

Schedule Page: 422.6 Line No.: 13 Column: a
Bundle

Schedule Page: 422.6 Line No.: 17 Column: a
Bundle

Schedule Page: 422.6 Line No.: 26 Column: a
Bundle

Schedule Page: 422.7 Line No.: 3 Column: a
Bundle

Schedule Page: 422.7 Line No.: 4 Column: a
Bundle

Schedule Page: 422.7 Line No.: 5 Column: a
Bundle

Schedule Page: 422.7 Line No.: 25 Column: a
Alum

Schedule Page: 422.7 Line No.: 26 Column: a
Alum
Schedule Page: 422.7 Line No.: 27 Column: a
Alum
Schedule Page: 422.7 Line No.: 28 Column: a
Alum
Schedule Page: 422.8 Line No.: 3 Column: a
Bundle
Schedule Page: 422.8 Line No.: 8 Column: a
Idle
Schedule Page: 422.8 Line No.: 12 Column: a
Idle
Schedule Page: 422.8 Line No.: 13 Column: a
Idle
Schedule Page: 422.8 Line No.: 15 Column: a
Idle
Schedule Page: 422.8 Line No.: 17 Column: a
Bundle
Schedule Page: 422.8 Line No.: 18 Column: a
Bundle, Idle
Schedule Page: 422.8 Line No.: 19 Column: a
Bundle
Schedule Page: 422.8 Line No.: 20 Column: a
Bundle, Idle
Schedule Page: 422.8 Line No.: 23 Column: a
Bundle
Schedule Page: 422.9 Line No.: 3 Column: a
Idle
Schedule Page: 422.10 Line No.: 5 Column: a
Bundle
Schedule Page: 422.11 Line No.: 6 Column: a
Idle
Schedule Page: 422.11 Line No.: 8 Column: a
Idle
Schedule Page: 422.12 Line No.: 7 Column: a
Idle
Schedule Page: 422.12 Line No.: 9 Column: a
Bundle
Schedule Page: 422.12 Line No.: 24 Column: a
Idle
Schedule Page: 422.13 Line No.: 16 Column: a
Alum
Schedule Page: 422.13 Line No.: 18 Column: a
Bundle
Schedule Page: 422.13 Line No.: 19 Column: a
Bundle
Schedule Page: 422.13 Line No.: 27 Column: a
Idle
Schedule Page: 422.15 Line No.: 3 Column: a
Bundle
Schedule Page: 422.15 Line No.: 6 Column: a
Bundle
Schedule Page: 422.15 Line No.: 11 Column: a
Bundle

Schedule Page: 422.16 Line No.: 18 Column: a
Bundle
Schedule Page: 422.16 Line No.: 19 Column: a
Bundle
Schedule Page: 422.16 Line No.: 22 Column: a
Idle
Schedule Page: 422.17 Line No.: 26 Column: a
Idle
Schedule Page: 422.18 Line No.: 25 Column: a
Idle
Schedule Page: 422.18 Line No.: 26 Column: a
Bundle
Schedule Page: 422.18 Line No.: 27 Column: a
Bundle
Schedule Page: 422.18 Line No.: 28 Column: a
Bundle
Schedule Page: 422.18 Line No.: 32 Column: a
Bundle
Schedule Page: 422.18 Line No.: 33 Column: a
Bundle
Schedule Page: 422.20 Line No.: 9 Column: a
Idle
Schedule Page: 422.20 Line No.: 10 Column: a
Idle
Schedule Page: 422.20 Line No.: 17 Column: a
Bundle
Schedule Page: 422.21 Line No.: 1 Column: a
Idle
Schedule Page: 422.21 Line No.: 2 Column: a
Idle
Schedule Page: 422.21 Line No.: 30 Column: a
Bundle
Schedule Page: 422.22 Line No.: 1 Column: a
Idle
Schedule Page: 422.22 Line No.: 2 Column: a
Bundle
Schedule Page: 422.23 Line No.: 12 Column: a
Idle
Schedule Page: 422.23 Line No.: 15 Column: a
Bundle
Schedule Page: 422.24 Line No.: 10 Column: a
Alum
Schedule Page: 422.24 Line No.: 21 Column: a
Alum
Schedule Page: 422.24 Line No.: 26 Column: a
Alum
Schedule Page: 422.24 Line No.: 27 Column: a
Alum
Schedule Page: 422.24 Line No.: 28 Column: a
Alum
Schedule Page: 422.24 Line No.: 29 Column: a
Alum
Schedule Page: 422.24 Line No.: 30 Column: a
Alum

Schedule Page: 422.24 Line No.: 31 Column: a
Alum
Schedule Page: 422.25 Line No.: 7 Column: a
Alum
Schedule Page: 422.25 Line No.: 30 Column: a
Idle
Schedule Page: 422.26 Line No.: 12 Column: a
Idle
Schedule Page: 422.28 Line No.: 23 Column: a
Idle
Schedule Page: 422.28 Line No.: 24 Column: a
Idle
Schedule Page: 422.28 Line No.: 32 Column: a
Alum
Schedule Page: 422.28 Line No.: 33 Column: a
Alum
Schedule Page: 422.29 Line No.: 24 Column: a
Idle
Schedule Page: 422.29 Line No.: 35 Column: a
Alum
Schedule Page: 422.30 Line No.: 21 Column: a
Alum
Schedule Page: 422.30 Line No.: 31 Column: a
Idle
Schedule Page: 422.30 Line No.: 35 Column: a
Idle
Schedule Page: 422.31 Line No.: 3 Column: a
Idle
Schedule Page: 422.31 Line No.: 8 Column: a
Bundle
Schedule Page: 422.31 Line No.: 16 Column: a
Bundle
Schedule Page: 422.31 Line No.: 29 Column: a
Idle
Schedule Page: 422.31 Line No.: 30 Column: a
Idle
Schedule Page: 422.31 Line No.: 32 Column: a
Idle
Schedule Page: 422.31 Line No.: 34 Column: a
Bundle
Schedule Page: 422.31 Line No.: 35 Column: a
Bundle
Schedule Page: 422.32 Line No.: 16 Column: a
Bundle
Schedule Page: 422.33 Line No.: 25 Column: a
Idle
Schedule Page: 422.33 Line No.: 30 Column: a
Bundle
Schedule Page: 422.36 Line No.: 6 Column: a
Idle
Schedule Page: 422.36 Line No.: 15 Column: a
Alum
Schedule Page: 422.36 Line No.: 32 Column: a
Idle

Schedule Page: 422.37 Line No.: 2 Column: a
Idle

Schedule Page: 422.37 Line No.: 3 Column: a
Idle

Schedule Page: 422.37 Line No.: 10 Column: a
Alum

Schedule Page: 422.38 Line No.: 13 Column: a
Idle

Schedule Page: 422.38 Line No.: 16 Column: a
Idle

Schedule Page: 422.38 Line No.: 24 Column: a
Idle

Schedule Page: 422.39 Line No.: 12 Column: a
Idle

Schedule Page: 422.39 Line No.: 21 Column: a
Bundle

Schedule Page: 422.41 Line No.: 5 Column: a
Idle

Schedule Page: 422.41 Line No.: 7 Column: a
Alum

Schedule Page: 422.41 Line No.: 9 Column: a
Alum

Schedule Page: 422.41 Line No.: 10 Column: a
Idle

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Reconductoring Work						
2	Overhead						
3							
4	Fulton-Fitch MTN. Recond						
5	Fulton	Fitch	3.00	TSP, LDSP	5.00	1	1
6	Job Order # 74000600						
7							
8	NRS Scott Reconductoring						
9	NRS	Scott No. 1	4.20	TSP	5.00	1	1
10	Job Order # 74000711						
11							
12	Herndon-Kearney 230KV Line						
13	Herndon	Kearney	2.30	Lattice Tower	7.00	1	1
14	Job Order # 74000841						
15							
16	Wheeker Ridge-Weedpatch						
17	Wheeler Ridge	Weedpatch Substation	2.50	TSP	14.00	1	1
18	Job Order #74001001						
19							
20	Metcalf-Evergreen						
21	Metcalf	Evergreen Substation	16.30	TSP	7.73	1	1
22	Job Order # 74000846						
23							
24	Kearney-Caruthers 70KV Line						
25	Kearney	Caruthers	12.00	TSP, WP	17.00	1	1
26	Job Order # 74000546						
27							
28	Midway-Kern PP#2 230KV						
29	Midway	Kern	28.00	Tower, TSP	4.50	1	1
30	Job Order # 74001031						
31							
32	Smynra-Semitrop-Midway						
33	Smyrna-Semitrop	Midway	21.61	Steel Poles	7.45	1	1
34	Job Order # 74001389						
35							
36	Stockton A Weber						
37	Stockton A	Weber	7.30	TSP, WP	14.50	1	1
38	Job Order # 74004615						
39							
40	Eagle Rock-Fulton-Silverado						
41	Fulton	Pueblo	3.49	LSP, TSP	4.00	1	1
42	Job Order # 74004615						
43							
44	TOTAL		126.09		129.40	16	16

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	Centerville-Table MNT						
2	Centerville	Table Mountain	1.10	WP	13.63	1	1
3	Job Order # 74015724						
4							
5	Gates-Tulare Lake 70KV						
6	Gates	Tulare Lake Substation	7.00	WP	3.42	1	1
7	Job Order # 74018601						
8							
9	Fulton-Calistoga 60KV Line						
10	Fulton	Calistoga	4.00	LSP	11.00	1	1
11	Job Order # 74020222						
12							
13	Silverado-Fulton JCT 115KV						
14	Silverado	Fulton JCT	9.14	Lattice Tower	3.61	2	2
15	Job Order # 74004618						
16							
17	Arco-Twisselman 70KV						
18	Arco Substation	Twisselman JCT	4.15	WP	11.56	1	1
19	Job Order # 74019280						
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	TOTAL		126.09		129.40	16	16

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
477	ACSS	Various	60	1,346,931	11,629,244	12,443,443		25,419,618	5
									6
									7
									8
3M	ACCR	Various	115	123,700	16,316	6,262,808		6,402,824	9
									10
									11
									12
3M	ACCR	Various	230	536,774	2,403,194	11,005,458		13,945,426	13
									14
									15
									16
715	AAC	Various	70		1,996,246	1,411,652		3,407,898	17
									18
									19
									20
477	ACSS	Various	115	34,196	4,057,691	17,999,153		22,091,040	21
									22
									23
									24
715	AAC	Various	70		1,298,389	4,253,569		5,551,958	25
									26
									27
									28
1113	ACSS	Various	230	888,648	3,716,619	16,552,663		21,157,930	29
									30
									31
									32
1113	AAC	Various	115		11,661,035	8,853,278		20,514,313	33
									34
									35
									36
715	AAC	Various	60		4,026,604	3,839,972		7,866,576	37
									38
									39
									40
477	ACSS	Various	115		2,612,133	6,074,410		8,686,543	41
									42
									43
				2,930,249	49,234,197	116,533,395		168,697,841	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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 KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
397	ACSR	Various	60		1,031,750	701,768		1,733,518	2
									3
									4
									5
4/0	AAC	Various	70		483,626	3,964,778		4,448,404	6
									7
									8
									9
397	ACSR	Various	60			14,055,225		14,055,225	10
									11
									12
									13
477	ACSS	Various	115		1,728,452	8,640,782		10,369,234	14
									15
									16
									17
715	AAC	Various	70		2,572,898	474,436		3,047,334	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
				2,930,249	49,234,197	116,533,395		168,697,841	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ARCO SUB, Lost Hills	Transmission	230.00	70.00	13.20
2	ATLANTIC SUB, Roseville	Transmission	230.00	60.00	13.20
3	ATLANTIC SUB, Roseville	Transmission	230.00	115.00	13.20
4	BAIR SUB, Redwood City	Transmission	115.00	60.00	13.20
5	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
6	BORDEN SUB, Madera	Transmission	230.00	70.00	13.20
7	BRIDGEVILLE SUB, Bridgeville	Transmission	115.00	60.00	13.20
8	BRIGHTON SUB, Sacramento	Transmission	230.00	115.00	13.20
9	BUTTE SUB, Chico	Transmission	115.00	60.00	13.20
10	CASCADE SUB, Pine Grove	Transmission	115.00	60.00	13.20
11	CHRISTIE SUB, Hercules	Transmission	115.00	60.00	13.20
12	COBURN SUB, King City	Transmission	230.00	60.00	13.20
13	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	60.00	13.20
14	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	115.00	13.20
15	COOLEY LANDING SUB, Palo Alto	Transmission	115.00	60.00	13.80
16	CORCORAN SUB, Corcoran	Transmission	115.00	70.00	13.20
17	CORTINA SUB, Williams	Transmission	115.00	60.00	13.20
18	CORTINA SUB, Williams	Transmission	230.00	115.00	13.20
19	COTTONWOOD SUB, Cottonwood	Transmission	230.00	60.00	13.20
20	COTTONWOOD SUB, Cottonwood	Transmission	230.00	115.00	13.20
21	DEL MONTE SUB, Monterey	Transmission	115.00	60.00	13.20
22	DIVIDE SUB, Orcutt	Transmission	115.00	70.00	13.20
23	EAGLE ROCK SUB, Geysers	Transmission	115.00	60.00	
24	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	60.00	
25	EASTSHORE SUB, Hayward	Transmission	230.00	115.00	
26	EVERGREEN SUB, San Jose	Transmission	115.00	60.00	13.20
27	FULTON SUB, Fulton	Transmission	115.00	60.00	13.20
28	FULTON SUB, Fulton	Transmission	230.00	115.00	13.20
29	GATES SUB, Huron	Transmission	115.00	70.00	13.20
30	GATES SUB, Huron	Transmission	230.00	115.00	13.20
31	GATES SUB, Huron	Transmission	500.00	230.00	13.20
32	GLENN SUB, Orland	Transmission	230.00	60.00	13.20
33	GOLD HILL SUB, Folsom	Transmission	115.00	60.00	13.20
34	GOLD HILL SUB, Folsom	Transmission	230.00	115.00	13.20
35	GREEN VALLEY SUB, Watsonville	Transmission	115.00	60.00	
36	HELM SUB, San Joaquin	Transmission	230.00	70.00	13.20
37	HENRIETTA SUB, Lamoore	Transmission	230.00	70.00	13.20
38	HENRIETTA SUB, Lamoore	Transmission	230.00	115.00	2.40
39	HERDLYN SUB, Tracy	Transmission	70.00	60.00	2.40
40	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HOPLAND SUB, Hopland	Transmission	115.00	60.00	13.20
2	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
3	IGNACIO SUB, Ignacio	Transmission	115.00	60.00	13.20
4	IGNACIO SUB, Ignacio	Transmission	230.00	115.00	13.20
5	JEFFERSON SUB, Redwood City	Transmission	230.00	60.00	13.20
6	KASSON SUB, Tracy	Transmission	115.00	60.00	13.20
7	KERN PP SUB, Bakersfield	Transmission	115.00	70.00	13.20
8	KERN PP SUB, Bakersfield	Transmission	230.00	115.00	13.20
9	KINGSBURG SUB, Kingsburg	Transmission	115.00	70.00	13.80
10	LAKEVILLE SUB, Petaluma	Transmission	230.00	60.00	13.20
11	LAKEVILLE SUB, Petaluma	Transmission	230.00	115.00	13.20
12	LAS POSITAS SUB, Livermore	Transmission	230.00	60.00	13.20
13	LOCKEFORD SUB, Lockeford	Transmission	230.00	60.00	13.20
14	LOS BANOS SUB, Los Banos	Transmission	230.00	70.00	13.20
15	LOS BANOS SUB, Los Banos	Transmission	500.00	230.00	13.80
16	LOS ESTEROS SUB,	Transmission	230.00	115.00	12.00
17	MANTECA SUB, Manteca	Transmission	115.00	60.00	13.20
18	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
19	MENDOCINO SUB, Redwood Valley	Transmission	115.00	60.00	13.20
20	MENDOTA SUB, Mendota	Transmission	115.00	70.00	12.00
21	MERCED SUB, Merced	Transmission	115.00	70.00	6.60
22	MESA SUB, Nipomo	Transmission	230.00	115.00	13.20
23	METCALF SUB, San Jose	Transmission	500.00	230.00	13.80
24	METCALF SUB, San Jose	Transmission	230.00	115.00	13.20
25	MIDWAY SUB, Buttonwillow	Transmission	230.00	115.00	13.20
26	MIDWAY SUB, Buttonwillow	Transmission	500.00	230.00	13.80
27	MILLBRAE SUB, Millbrae	Transmission	115.00	60.00	13.80
28	MONTA VISTA SUB, Cupertino	Transmission	115.00	60.00	13.20
29	MONTA VISTA SUB, Cupertino	Transmission	230.00	115.00	13.20
30	MORAGA SUB, Orinda	Transmission	230.00	115.00	13.20
31	MORRO BAY PP SWYD, Morro Bay	Transmission	230.00	115.00	13.20
32	MOSS LANDING PP SUB, Moss Landing	Transmission	230.00	115.00	13.20
33	MOSS LANDING PP SUB, Moss Landing	Transmission	500.00	230.00	13.80
34	NEW KEARNEY SUB, FRESNO	Transmission	230.00	70.00	13.20
35	NEWARK SUB, Fremont	Transmission	115.00	60.00	13.20
36	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
37	ORO LOMA SUB, Dos Palos	Transmission	115.00	70.00	13.20
38	PALERMO SUB, Palermo	Transmission	230.00	60.00	
39	PALERMO SUB, Palermo	Transmission	230.00	115.00	13.20
40	PANOCHE SUB, Mendota	Transmission	230.00	115.00	13.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	PEASE SUB, Tierra Buena	Transmission	115.00	60.00	13.20
2	PITTSBURG PP SUB,	Transmission	230.00	115.00	13.20
3	PLACER SUB, Auburn	Transmission	115.00	60.00	
4	RAVENSWOOD SUB, Menlo Park	Transmission	230.00	115.00	13.20
5	REEDLEY SUB, Reedley	Transmission	115.00	70.00	13.20
6	RIO OSO SUB, Rio Oso	Transmission	230.00	115.00	13.20
7	ROUND MOUNTAIN SUB, Rd Mtn	Transmission	500.00	230.00	13.80
8	SALADO SUB, Patterson	Transmission	115.00	60.00	13.20
9	SALINAS SUB, Salinas	Transmission	115.00	60.00	13.20
10	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	230.00	115.00	13.20
11	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	60.00	
12	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	230.00	115.00	
13	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	70.00	13.20
14	SAN MATEO SUB, San Mateo	Transmission	115.00	60.00	
15	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
16	SAN RAMON SUB, San Ramon	Transmission	230.00	60.00	13.20
17	SANGER SUB, Fresno	Transmission	115.00	70.00	6.60
18	SCHINDLER SUB, Five Points	Transmission	115.00	70.00	13.20
19	SEMITROPIC SUB, Wasco	Transmission	115.00	70.00	13.80
20	SOBRANTE SUB, Orinda	Transmission	230.00	115.00	
21	SOLEDAD SUB, Soledad	Transmission	115.00	60.00	
22	STAGG SUB, Stockton	Transmission	230.00	60.00	13.20
23	TABLE MOUNTAIN SUB, Oroville	Transmission	230.00	115.00	
24	TABLE MOUNTAIN SUB, Oroville	Transmission	500.00	230.00	13.80
25	TAFT SUB, Taft	Transmission	115.00	70.00	13.20
26	TEMPLETON SUB, TEMPLETON	Transmission	230.00	70.00	13.20
27	TESLA SUB, Tracy	Transmission	230.00	115.00	13.20
28	TESLA SUB, Tracy	Transmission	500.00	230.00	13.20
29	TRINITY SUB, Weaverville	Transmission	115.00	60.00	13.20
30	TULUCAY SUB, Napa	Transmission	230.00	60.00	13.20
31	VACA DIXON SUB, Vacaville	Transmission	115.00	60.00	13.20
32	VACA DIXON SUB, Vacaville	Transmission	230.00	115.00	13.20
33	VACA DIXON SUB, Vacaville	Transmission	500.00	230.00	13.80
34	VALLEY SPRINGS SUB, Valley Springs	Transmission	230.00	60.00	13.20
35	WEBER SUB, Stockton	Transmission	230.00	60.00	13.20
36	WHEELER RIDGE SUB, Bakersfield	Transmission	115.00	70.00	13.20
37	WHEELER RIDGE SUB, Bakersfield	Transmission	230.00	70.00	13.20
38	WILSON SUB, Merced	Transmission	230.00	115.00	13.20
39	7th STANDARD SUB, Bakersfield	Distribution	115.00	21.00	
40	AIRWAYS SUB, Fresno, Ca.	Distribution	115.00	12.00	7.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	ALHAMBRA SUB, Martinez	Distribution	115.00	12.00	7.20
2	ALLEGHANY SUB, Alleghany	Distribution	60.00	12.00	7.20
3	ALMADEN SUB, San Jose	Distribution	60.00	12.00	7.20
4	ALPAUGH SUB, Tulare	Distribution	115.00	12.00	
5	ALTO SUB, Mill Valley	Distribution	60.00	12.00	2.40
6	AMES DISTRIBUTION SUB, Mountain View	Distribution	115.00	12.00	7.20
7	ANDERSON SUB, Anderson	Distribution	60.00	12.00	2.40
8	ANGIOLA SUB, Kings	Distribution	70.00	12.00	7.20
9	ANITA SUB, Chico	Distribution	60.00	12.00	2.40
10	ANTELOPE SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
11	ANTLER SUB, Lakehead	Distribution	60.00	12.00	2.40
12	APPLE HILL SUB, Camino	Distribution	115.00	12.00	7.20
13	APPLE HILL SUB, Camino	Distribution	115.00	21.00	7.20
14	ARBUCKLE SUB, ARBUCKLE	Distribution	60.00	12.00	7.20
15	ARCATA SUB, Arcata	Distribution	60.00	12.00	2.40
16	ARVIN SUB, Arvin	Distribution	70.00	12.00	2.40
17	ASHLAN AVENUE SUB, Fresno	Distribution	230.00	12.00	7.20
18	ATASCADERO SUB, Atascadero	Distribution	115.00	12.00	7.20
19	ATWATER SUB, Atwater	Distribution	115.00	12.00	7.20
20	AUBERRY SUB, Auberry	Distribution	70.00	12.00	7.20
21	AVENA SUB, Escalon	Distribution	115.00	12.00	
22	AVENAL SUB, Avenal	Distribution	70.00	12.00	
23	BAHIA SUB, Benicia	Distribution	230.00	12.00	7.20
24	BAIR SUB, Redwood City	Transmission	115.00	12.00	7.20
25	BAKERSFIELD SUB, Bakersfield	Distribution	230.00	21.00	7.20
26	BANGOR SUB, Bangor	Distribution	60.00	12.00	7.20
27	BARTON SUB, Fresno	Distribution	115.00	12.00	7.20
28	BASALT SUB, Napa	Distribution	60.00	12.00	2.40
29	BAY MEADOWS SUB, San Mateo	Distribution	115.00	21.00	7.20
30	BAY MEADOWS SUB, San Mateo	Distribution	115.00	12.00	7.20
31	BAYWOOD SUB, Morro Bay	Distribution	70.00	12.00	2.40
32	BEAR VALLEY SUB, Bear Valley	Distribution	70.00	21.00	7.20
33	BELL SUB, Auburn	Distribution	115.00	12.00	7.20
34	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	12.00	2.40
35	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	4.00	2.40
36	BELLEVUE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
37	BELMONT SUB, Belmont	Distribution	115.00	12.00	7.20
38	BERRENDA A SUB,	Distribution	70.00	4.00	2.40
39	BIG BASIN SUB, Santa Cruz	Distribution	60.00	12.00	
40	BIG MEADOWS SUB, Greenville	Distribution	60.00	44.00	2.40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	BIOLA SUB, Biola	Distribution	70.00	12.00	2.40
2	BLACKWELL SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
3	BLUE LAKE SUB, Blue Lake	Distribution	60.00	12.00	2.40
4	BOGUE SUB, Yuba City	Distribution	115.00	12.00	7.20
5	BOLINAS SUB, Boninas	Distribution	60.00	12.00	7.20
6	BONITA SUB, Madera	Distribution	70.00	12.00	7.20
7	BORDEN SUB, Madera	Transmission	230.00	12.00	7.20
8	BOWLES SUB, Bowles	Distribution	70.00	12.00	7.20
9	BRENTWOOD SUB, Brentwood	Distribution	230.00	21.00	7.20
10	BRITTON SUB, Sunnyvale	Distribution	115.00	12.00	
11	BRUNSWICK SUB, Grass Valley	Distribution	115.00	12.00	7.20
12	BUELLTON SUB, Buellton /93427	Distribution	115.00	12.00	7.20
13	BUENA VISTA SUB, Salinas	Distribution	60.00	12.00	7.20
14	BULLARD SUB, Fresno	Distribution	115.00	12.00	7.20
15	BULLARD SUB, Fresno	Distribution	115.00	21.00	7.20
16	BURLINGAME SUB, Burlingame	Distribution	115.00	21.00	7.20
17	BUTTE SUB, Chico	Transmission	115.00	12.00	7.20
18	CABRILLO SUB, LOMPOC	Distribution	115.00	12.00	7.20
19	CADET SUB, Maricopa	Distribution	70.00	12.00	
20	CAL WATER SUB,	Distribution	115.00	12.00	7.20
21	CALAVERAS CEMENT SUB, San Andreas	Distribution	60.00	12.00	7.20
22	CALFLAX SUB, Huron	Distribution	70.00	12.00	2.40
23	CALIFORNIA AVE SUB, Fresno	Distribution	115.00	12.00	7.20
24	CALISTOGA SUB, Calistoga	Distribution	60.00	12.00	7.20
25	CALPELLA SUB, Calpella	Distribution	115.00	12.00	7.20
26	CAMDEN SUB, Riverdale	Distribution	70.00	12.00	2.40
27	CAMP EVERS SUB, Santa Cruz	Distribution	115.00	21.00	7.20
28	CAMPHORA SUB, Monterey	Distribution	60.00	12.00	7.20
29	CAMPHORA SUB, Monterey	Distribution	60.00	4.00	
30	CANAL SUB, Los Banos	Distribution	70.00	12.00	7.20
31	CANTUA SUB, Cantua Creek	Distribution	115.00	12.00	
32	CAPAY SUB, Orland	Distribution	60.00	12.00	2.40
33	CARBONA SUB, Tracy	Distribution	60.00	12.00	7.20
34	CARNATION SUB, Bakersfield	Distribution	70.00	21.00	7.20
35	CARNERAS SUB, Blackwells Corner	Distribution	70.00	12.00	7.20
36	CAROLANDS SUB, Hillsborough	Distribution	60.00	4.00	
37	CARQUINEZ SUB, Vallejo	Distribution	115.00	12.00	2.40
38	CARUTHERS SUB, Fresno	Distribution	70.00	12.00	2.40
39	CASSIDY SUB, Madera	Distribution	70.00	12.00	2.40
40	CASTRO VALLEY SUB, Castro Valley	Distribution	230.00	12.00	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	CASTROVILLE SUB, Castroville	Distribution	115.00	21.00	7.20
2	CATLETT SUB, Pleasant Grove	Distribution	60.00	12.00	
3	CAWELO B SUB, Famosa	Distribution	70.00	4.00	
4	CAYETANO SUB, Danville	Distribution	230.00	21.00	7.20
5	CAYUCOS SUB, Cayucos	Distribution	70.00	12.00	7.20
6	CHANNEL SUB, Stockton	Distribution	60.00	12.00	
7	CHARCA SUB, Wasco	Distribution	115.00	12.00	7.20
8	CHEROKEE SUB, Stockton	Distribution	60.00	12.00	7.20
9	CHICO A SUB, Chico	Distribution	60.00	12.00	7.20
10	CHICO B SUB, Chico	Distribution	115.00	12.00	7.20
11	CHOLAME SUB, Cholame/93431	Distribution	70.00	12.00	2.40
12	CHOLAME SUB, Cholame/93431	Distribution	70.00	21.00	2.40
13	CHOWCHILLA SUB, Chowchilla	Distribution	115.00	12.00	7.20
14	CLARK ROAD SUB, Paradise	Distribution	60.00	12.00	2.40
15	CLARKSVILLE SUB, Clarksville	Distribution	115.00	21.00	7.20
16	CLAY SUB, Ione	Distribution	60.00	12.00	2.40
17	CLAYTON SUB, Concord	Distribution	115.00	21.00	7.20
18	CLAYTON SUB, Concord	Distribution	115.00	12.00	7.20
19	CLEAR LAKE SUB, Finley	Distribution	60.00	12.00	2.40
20	CLOVERDALE SUB, Cloverdale	Distribution	115.00	12.00	7.20
21	CLOVIS SUB, Clovis	Distribution	115.00	12.00	7.20
22	CLOVIS SUB, Clovis	Distribution	115.00	21.00	7.20
23	COALINGA #1 SUB, Coalinga	Distribution	70.00	12.00	7.20
24	COALINGA #2 SUB, Coalinga	Distribution	70.00	12.00	2.40
25	COARSEGOLD SUB, Coursegold	Distribution	115.00	21.00	7.20
26	COLUMBUS SUB, Bakersfield	Distribution	115.00	12.00	7.20
27	COLUSA JUNCT SUB, Colusa	Distribution	60.00	12.00	7.20
28	COLUSA SUB, Colusa	Distribution	60.00	12.00	
29	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	21.00	7.20
30	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	21.00	6.60
31	COPPERMINE SUB, Clovis	Distribution	70.00	12.00	2.40
32	COPUS SUB, Bakersfield	Distribution	70.00	12.00	
33	CORCORAN SUB, Corcoran	Transmission	115.00	12.00	7.20
34	CORDELIA SUB, Cordelia	Distribution	115.00	12.00	7.20
35	CORDELIA SUB, Cordelia	Distribution	60.00	12.00	2.40
36	CORNING SUB, Corning	Distribution	60.00	12.00	2.40
37	CORONA SUB,	Distribution	115.00	12.00	7.20
38	CORRAL SUB, Bellota	Distribution	60.00	12.00	7.20
39	CORTINA SUB, Williams	Transmission	115.00	12.00	7.20
40	COTATI SUB, Cotati	Distribution	60.00	12.00	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	COTTLE SUB, Oakdale	Distribution	230.00	17.00	
2	COTTONWOOD SUB, Cottonwood	Transmission	115.00	12.00	7.20
3	COUNTRY CLUB SUB, Stockton	Distribution	60.00	12.00	
4	COUNTRY CLUB SUB, Stockton	Distribution	60.00	4.00	
5	CRESSEY SUB, Merced	Distribution	115.00	21.00	
6	CURTIS SUB, Sonora	Distribution	115.00	18.00	
7	CUYAMA SUB, Cuyama	Distribution	70.00	12.00	
8	CUYAMA SUB, Cuyama	Distribution	70.00	21.00	7.20
9	CYMRIC SUB, McKitrick	Distribution	115.00	12.00	7.20
10	DAIRYLAND SUB, Chowchilla	Distribution	115.00	12.00	7.20
11	DALY CITY SUB, Daly City	Distribution	115.00	12.00	7.20
12	DAVIS SUB, Davis	Distribution	115.00	12.00	7.20
13	DEEPWATER SUB, W. Sactramento	Distribution	115.00	12.00	7.20
14	DEL MAR SUB, Rocklin	Distribution	60.00	21.00	7.20
15	DEL MAR SUB, Rocklin	Distribution	60.00	12.00	7.20
16	DEL MONTE SUB, Monterey	Transmission	115.00	21.00	7.20
17	DERRICK SUB, Kettleman	Distribution	70.00	12.00	2.40
18	DESCHUTES SUB, Palo Cedro	Distribution	60.00	12.00	7.20
19	DIAMOND SPRINGS SUB, Placerville	Distribution	115.00	12.00	7.20
20	DINUBA SUB, Dinuba	Distribution	70.00	12.00	7.20
21	DIVIDE SUB, Orcutt	Transmission	70.00	12.00	2.40
22	DIVIDE SUB, Orcutt	Transmission	115.00	12.00	7.20
23	DIXON LANDING SUB,	Distribution	115.00	21.00	7.20
24	DIXON SUB, Dixon	Distribution	60.00	12.00	
25	DOLAN ROAD SUB, Moss Landing	Distribution	115.00	12.00	
26	DOS PALOS SUB, Dos Palos	Distribution	70.00	12.00	7.20
27	DUMBARTON SUB, Fremont	Distribution	115.00	12.00	
28	DUNBAR SUB, Glen Ellen	Distribution	60.00	12.00	
29	EAST GRAND SUB, So San Fran.	Distribution	115.00	12.00	7.20
30	EAST MARYSVILLE SUB, Marysville,	Distribution	115.00	12.00	7.20
31	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	12.00	
32	EAST STOCKTON SUB, Stockton	Distribution	60.00	12.00	7.20
33	EAST STOCKTON SUB, Stockton	Distribution	60.00	4.00	
34	EDENVALE SUB, San Jose	Distribution	115.00	21.00	7.20
35	EDENVALE SUB, San Jose	Distribution	115.00	12.00	7.20
36	EDES SUB, Oakland	Distribution	115.00	12.00	7.20
37	EEL RIVER SUB, Ferndale	Distribution	60.00	12.00	7.20
38	EIGHT MILE SUB, Stockton	Distribution	230.00	21.00	7.20
39	EL CAPITAN SUB, Snelling	Distribution	115.00	12.00	
40	EL CAPITAN SUB, Snelling	Distribution	115.00	21.00	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	EL CERRITO G SUB, El Cerrito	Distribution	115.00	12.00	
2	EL NIDO SUB, Merced	Distribution	115.00	12.00	7.20
3	EL PATIO SUB, Campbell	Distribution	115.00	12.00	7.20
4	EL PECO SUB, Madera	Distribution	70.00	12.00	
5	ELECTRA SUB,	Distribution	60.00	12.00	
6	ELK HILLS SUB, Valley Acres	Distribution	70.00	12.00	
7	ELK SUB, Elk	Distribution	60.00	12.00	2.40
8	EUREKA A SUB, Eureka	Distribution	60.00	12.00	7.20
9	EUREKA E SUB, Eureka	Distribution	60.00	12.00	
10	EVERGREEN SUB, San Jose	Transmission	115.00	21.00	7.20
11	FAIRHAVEN SUB, Fairhaven	Distribution	60.00	12.00	7.20
12	FAIRVIEW SUB, Martinez	Distribution	115.00	21.00	12.00
13	FAIRWAY SUB, Santa Maria	Distribution	115.00	12.00	7.20
14	FAMOSO SUB, Famosa	Distribution	115.00	12.00	
15	FELLOWS SUB, Fellows	Distribution	115.00	21.00	
16	FIGARDEN SUB, Fresno	Distribution	230.00	21.00	7.20
17	FIREBAUGH SUB, Firebaugh	Distribution	70.00	12.00	7.20
18	FITCH MOUNTAIN SUB, Healdsburg	Distribution	60.00	12.00	7.20
19	FLINT SUB, Auburn	Distribution	115.00	12.00	7.20
20	FMC SUB, San Jose	Distribution	115.00	12.00	7.20
21	FOOTHILL SUB, SLO	Distribution	115.00	12.00	2.40
22	FORESTHILL SUB, Foresthill,	Distribution	60.00	12.00	7.20
23	FORT BRAGG A SUB, Fort Bragg	Distribution	60.00	12.00	
24	FORT ORD SUB, Fort Ord	Distribution	60.00	21.00	7.20
25	FORT ORD SUB, Fort Ord	Distribution	60.00	12.00	2.40
26	FRANKLIN SUB, Hercules	Distribution	60.00	12.00	7.20
27	FREMONT SUB, Fremont	Distribution	115.00	12.00	7.20
28	FRENCH CAMP SUB, Stockton	Distribution	60.00	12.00	
29	FROGTOWN SUB, Angels Camp	Distribution	115.00	17.00	
30	FRUITVALE SUB, Bakersfield	Distribution	70.00	12.00	2.40
31	FULTON SUB, Fulton	Transmission	230.00	12.00	7.20
32	GABILAN SUB, Salinas	Distribution	115.00	12.00	7.20
33	GALLO SUB, Livingston	Distribution	115.00	12.00	
34	GANSNER SUB, Quincy	Distribution	60.00	12.00	7.20
35	GANSO SUB, Buttonwillow	Distribution	115.00	12.00	7.20
36	GARBERVILLE SUB, Garberville	Distribution	60.00	12.00	7.20
37	GATES SUB, Huron	Transmission	230.00	12.00	7.20
38	GATES SUB, Huron	Transmission	115.00	12.00	
39	GEYSERVILLE SUB, Geyserville	Distribution	60.00	12.00	2.40
40	GIFFEN SUB, San Joaquin	Distribution	70.00	12.00	2.40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GIRVAN SUB, Redding	Distribution	60.00	12.00	7.20
2	GLENN SUB, Orland	Transmission	60.00	12.00	
3	GLENWOOD SUB, Menlo Park	Distribution	60.00	12.00	7.20
4	GLENWOOD SUB, Menlo Park	Distribution	60.00	4.00	
5	GOLDTREE SUB, SLO	Distribution	115.00	12.00	7.20
6	GONZALES SUB, Gonzales	Distribution	60.00	12.00	
7	GOOSE LAKE SUB, Wasco	Distribution	115.00	12.00	7.20
8	GRAND ISLAND SUB, Ryde	Distribution	115.00	21.00	7.20
9	GRANT SUB, San Lorenzo	Distribution	115.00	12.00	7.20
10	GRASS VALLEY SUB, Grass Valley	Distribution	60.00	12.00	
11	GREEN VALLEY SUB, Watsonville	Transmission	115.00	21.00	7.20
12	GREENBRAE SUB, Larkspur	Distribution	60.00	12.00	7.20
13	GUALALA SUB, Gualala	Distribution	60.00	12.00	2.40
14	GUERNSEY SUB, Hanford	Distribution	70.00	12.00	
15	GUSTINE SUB, Gustine	Distribution	60.00	12.00	7.20
16	HALF MOON BAY SUB, Half Moon Bay	Distribution	60.00	12.00	2.40
17	HAMMER SUB, Stockton	Distribution	60.00	12.00	7.20
18	HAMMONDS SUB, Fresno	Distribution	115.00	12.00	
19	HARDING SUB, Stockton	Distribution	60.00	4.00	
20	HARDWICK SUB, Layton	Distribution	70.00	12.00	7.20
21	HARRIS SUB, Eureka	Distribution	60.00	12.00	7.20
22	HARTER SUB, Yuba City	Distribution	60.00	12.00	7.20
23	HARTLEY SUB, Lakeport	Distribution	60.00	12.00	7.20
24	HATTON SUB, Carmel Valley	Distribution	60.00	12.00	2.40
25	HENRIETTA SUB, Lemoore	Transmission	70.00	12.00	2.40
26	HERDLYN SUB, Tracy	Transmission	60.00	12.00	2.40
27	HICKS SUB, San Jose	Distribution	230.00	21.00	7.20
28	HICKS SUB, San Jose	Distribution	230.00	12.00	7.20
29	HIGGINS SUB, Higgins Corner	Distribution	115.00	12.00	7.20
30	HIGHLANDS SUB, Clear Lake	Distribution	115.00	12.00	7.20
31	HIGHWAY SUB, Petaluma	Distribution	115.00	12.00	7.20
32	HOLLISTER SUB, Hollister	Distribution	115.00	21.00	7.20
33	HOLLISTER SUB, Hollister	Distribution	60.00	21.00	
34	HONCUT SUB, Honcut	Distribution	115.00	12.00	7.20
35	HOPLAND SUB, Hopland	Transmission	60.00	12.00	2.40
36	HORSESHOE SUB, Granite Bay	Distribution	115.00	12.00	7.20
37	HOWLAND ROAD SUB, Manteca	Distribution	115.00	12.00	7.20
38	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	13.80	
39	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	13.80	
40	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	12.00	7.20

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	2.00	
2	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	2.00	
3	HURON SUB, Huron	Distribution	70.00	12.00	2.40
4	IGNACIO SUB, Ignacio	Transmission	115.00	12.00	
5	IMHOFF SUB, Martinez	Distribution	115.00	12.00	7.20
6	IONE SUB, Ione	Distribution	60.00	12.00	7.20
7	JACINTO SUB, Willows	Distribution	60.00	12.00	7.20
8	JACOBS CORNER SUB, Lemoore	Distribution	70.00	12.00	2.40
9	JAMESON SUB, CORDELIA	Distribution	115.00	12.00	7.20
10	JANES CREEK SUB, Arcata	Distribution	60.00	12.00	7.20
11	JARVIS SUB, Union City	Distribution	115.00	12.00	7.20
12	JESSUP SUB, Anderson	Distribution	115.00	12.00	
13	JOLON SUB, King City	Distribution	60.00	12.00	
14	KELSO SUB, Tracy	Distribution	230.00	12.00	
15	KERMAN SUB, Kerman	Distribution	70.00	12.00	7.20
16	KERN OIL SUB, Bakersfield	Distribution	115.00	12.00	7.20
17	KERN PP DIST SUB, Bakersfield	Distribution	115.00	21.00	7.20
18	KESWICK SUB, Keswick	Distribution	60.00	12.00	2.40
19	KETTLEMAN HILLS SUB, Kettleman	Distribution	70.00	12.00	2.40
20	KING CITY SUB, King City	Distribution	60.00	12.00	
21	KINGSBURG SUB, Kingsburg	Transmission	115.00	12.00	7.20
22	KIRKER SUB, Pittsburg	Distribution	115.00	21.00	7.20
23	KONOCTI SUB, Clear Lake	Distribution	60.00	12.00	2.40
24	LAKEVIEW SUB, Bakersfield	Distribution	70.00	12.00	2.40
25	LAKEVILLE SUB, Petaluma	Transmission	115.00	12.00	7.20
26	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	21.00	7.20
27	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	12.00	7.20
28	LAMMERS SUB, TRACY	Distribution	115.00	12.00	7.20
29	LAMONT SUB, Bakersfield	Distribution	115.00	12.00	
30	LAS GALLINAS A SUB, Las Gallinas	Distribution	115.00	12.00	7.20
31	LAS PALMAS SUB, Fresno	Distribution	115.00	12.00	7.20
32	LAS POSITAS SUB, Livermore	Transmission	230.00	21.00	7.20
33	LAS PULGAS SUB, Redwood City	Distribution	60.00	4.00	2.40
34	LAWRENCE SUB, Sunnyvale	Distribution	115.00	12.00	7.20
35	LE GRAND SUB, Le Grand	Distribution	115.00	12.00	7.20
36	LEMOORE SUB, Armonia	Distribution	70.00	12.00	2.40
37	LERDO SUB, Bakersfield	Distribution	115.00	12.00	7.20
38	LINCOLN SUB, Lincoln	Distribution	115.00	12.00	7.20
39	LINDEN SUB, Linden	Distribution	60.00	12.00	2.40
40	LIVE OAK SUB, Live Oak	Distribution	60.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	LIVERMORE SUB, Livermore	Distribution	60.00	12.00	2.40
2	LIVINGSTON SUB, Livingston	Distribution	115.00	12.00	7.20
3	LIVINGSTON SUB, Livingston	Distribution	70.00	12.00	
4	LLAGAS SUB, Gilroy	Distribution	115.00	21.00	12.00
5	LOCKEFORD SUB, Lockeford	Transmission	115.00	21.00	7.20
6	LOCKHEED #1 SUB, Sunnyvale	Distribution	115.00	12.00	7.20
7	LOCKHEED #2 SUB, Sunnyvale	Distribution	115.00	12.00	
8	LODI SUB, Lodi	Distribution	60.00	12.00	2.40
9	LODI SUB, Lodi	Distribution	60.00	4.00	
10	LOGAN CREEK SUB, Willows	Distribution	230.00	21.00	
11	LONETREE SUB, Antioch	Distribution	230.00	21.00	7.20
12	LOS ALTOS SUB, Los Altos	Distribution	60.00	12.00	
13	LOS COCHES SUB, Greenfield	Distribution	60.00	12.00	
14	LOS GATOS SUB, Los Gatos	Distribution	60.00	12.00	7.20
15	LOS MOLINOS SUB, Los Molinos	Distribution	60.00	12.00	7.20
16	LOS OSITOS SUB, Monterey	Distribution	60.00	21.00	7.20
17	LOYOLA SUB, Loyola	Distribution	60.00	12.00	7.20
18	LOYOLA SUB, Loyola	Distribution	60.00	4.00	2.40
19	LUCERNE SUB, Lucerne	Distribution	115.00	12.00	7.20
20	MABURY SUB, San Jose	Distribution	60.00	12.00	2.40
21	MABURY SUB, San Jose	Distribution	60.00	12.00	7.20
22	MADERA SUB, Madera	Distribution	70.00	12.00	
23	MADISON SUB, Madison	Distribution	60.00	12.00	7.20
24	MADISON SUB, Madison	Distribution	115.00	12.00	
25	MAGUNDEN SUB, Bakersfield	Distribution	115.00	12.00	7.20
26	MAGUNDEN SUB, Bakersfield	Distribution	115.00	21.00	7.20
27	MALAGA SUB, Fresno	Distribution	115.00	12.00	7.20
28	MANCHESTER SUB, Fresno	Distribution	115.00	12.00	7.20
29	MANTECA SUB, Manteca	Transmission	115.00	17.00	
30	MARICOPA SUB, Maricopa	Distribution	70.00	12.00	2.40
31	MARIPOSA SUB, Mariposa	Distribution	70.00	21.00	
32	MARTELL SUB, Martell	Distribution	60.00	12.00	2.40
33	MARYSVILLE SUB, Marysville	Distribution	60.00	12.00	
34	MAXWELL SUB, Maxwell	Distribution	60.00	12.00	
35	MCARTHUR SUB, McArthur	Distribution	60.00	12.00	2.40
36	MCCALL SUB, Selma	Transmission	115.00	12.00	7.20
37	MCDONALD-MCDONALDISLAND SUB, Stockton	Distribution	60.00	4.00	2.40
38	MCFARLAND SUB, McFarland	Distribution	70.00	12.00	7.20
39	MCKEE SUB, San Jose	Distribution	115.00	12.00	7.20
40	MCKITTRICK SUB, MCKITTRICK	Distribution	70.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	MCMULLIN SUB, Fresno	Distribution	230.00	12.00	7.20
2	MEADOW LANE SUB, Concord	Distribution	115.00	21.00	7.20
3	MENDOCINO SUB, Redwood Valley	Transmission	60.00	12.00	2.40
4	MENDOTA SUB, Mendota	Transmission	115.00	12.00	7.20
5	MENLO SUB, Menlo Park	Distribution	60.00	12.00	7.20
6	MENLO SUB, Menlo Park	Distribution	60.00	4.00	
7	MERCED SUB, Merced	Transmission	115.00	12.00	7.20
8	MERCED SUB, Merced	Transmission	115.00	21.00	7.20
9	MERIDIAN SUB, Meridian	Distribution	60.00	12.00	
10	MESA SUB, Nipomo	Transmission	230.00	12.00	
11	METTLER SUB, Stockton	Distribution	60.00	12.00	
12	MIDDLETOWN SUB, Middletown	Distribution	60.00	12.00	7.20
13	MIDWAY SUB, Buttonwillow	Transmission	115.00	12.00	7.20
14	MILLBRAE SUB, Millbrae	Transmission	115.00	12.00	
15	MILLBRAE SUB, Millbrae	Transmission	60.00	4.00	
16	MILPITAS SUB, Milpitas	Distribution	115.00	21.00	7.20
17	MILPITAS SUB, Milpitas	Distribution	115.00	12.00	7.20
18	MIRABEL SUB, Forestville	Distribution	60.00	12.00	
19	MI-WUK SUB, Sugarpine	Distribution	115.00	17.00	
20	MOLINO SUB, Sebastopol	Distribution	60.00	12.00	7.20
21	MONROE SUB, Santa Rosa	Distribution	115.00	21.00	7.20
22	MONROE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
23	MONTAGUE SUB, San Jose	Distribution	115.00	21.00	7.20
24	MONTE RIO SUB, Monte Rio	Distribution	60.00	12.00	7.20
25	MONTEREY SUB, Monterey	Distribution	60.00	4.00	
26	MORAGA SUB, Orinda	Transmission	115.00	12.00	
27	MORGAN HILL SUB, Morgan Hill	Distribution	115.00	21.00	7.20
28	MORMON SUB, Stockton	Distribution	60.00	12.00	7.20
29	MORRO BAY PP SWYD, Morro Bay	Transmission	115.00	12.00	7.20
30	MOSHER SUB, Stockton	Distribution	60.00	21.00	7.20
31	MOUNTAIN VIEW SUB, Mt. View	Distribution	115.00	12.00	7.20
32	MT. EDEN SUB, Hayward	Distribution	115.00	12.00	7.20
33	MT. QUARRIES SUB, Cool	Distribution	60.00	12.00	7.20
34	NAPA SUB, Napa	Distribution	60.00	12.00	
35	NARROWS SUB,	Distribution	60.00	21.00	7.20
36	NEWARK DIST SUB, Fremont	Distribution	230.00	21.00	7.20
37	NEWARK SUB, Fremont	Transmission	115.00	12.00	7.20
38	NEWBURG SUB, Fortuna	Distribution	60.00	12.00	2.40
39	NEWHALL SUB, Firebaugh	Distribution	115.00	12.00	7.20
40	NEWMAN SUB, Newman	Distribution	60.00	12.00	7.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	NORCO SUB, Bakersfield	Distribution	115.00	12.00	7.20
2	NORD SUB, Chico	Distribution	115.00	12.00	7.20
3	NORTECH SUB, San Jose	Distribution	115.00	21.00	7.20
4	NORTH DUBLIN SUB, Pleasanton	Distribution	230.00	21.00	12.00
5	NORTH TOWER SUB, Vallejo	Distribution	115.00	12.00	7.20
6	NOTRE DAME SUB, Chico	Distribution	115.00	12.00	7.20
7	NOVATO SUB, Novato	Distribution	60.00	12.00	7.20
8	OAKHURST SUB, Oakhurst	Distribution	115.00	12.00	2.40
9	OAKLAND C (OAKLAND PP) SUB, Oakland	Distribution	115.00	12.00	7.20
10	OAKLAND D SUB, Oakland	Distribution	115.00	12.00	7.20
11	OAKLAND J SUB, Oakland	Distribution	115.00	12.00	7.20
12	OAKLAND K (CLAREMONT) SUB, Oakland	Distribution	115.00	12.00	6.60
13	OAKLAND L SUB, Oakland	Distribution	115.00	12.00	7.20
14	OAKLAND X SUB, Oakland	Distribution	115.00	12.00	7.20
15	OCEANO SUB, Oceano	Distribution	115.00	12.00	7.20
16	OILFIELDS SUB, San Ardo	Distribution	60.00	12.00	
17	OLD KEARNEY SUB, Fresno	Distribution	70.00	12.00	13.20
18	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	2.40
19	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	7.20
20	OLETA SUB, Plymouth	Distribution	60.00	12.00	2.40
21	OLIVEHURST SUB, Olivehurst	Distribution	115.00	12.00	7.20
22	OREGON TRAIL SUB, Redding	Distribution	115.00	12.00	7.20
23	OREGON TRAIL SUB, Redding	Distribution	60.00	12.00	2.40
24	ORLAND B SUB, Orland	Distribution	60.00	12.00	2.40
25	ORO FINO SUB, Magalia	Distribution	60.00	12.00	2.40
26	ORO LOMA SUB, Dos Palos	Transmission	70.00	12.00	2.40
27	ORO LOMA SUB, Dos Palos	Transmission	115.00	12.00	
28	OROSI SUB, Orosi	Distribution	70.00	12.00	7.20
29	OROVILLE SUB, Oroville	Distribution	60.00	12.00	7.20
30	OROVILLE SUB, Oroville	Distribution	60.00	4.00	2.40
31	ORTIGA SUB, Los Banos	Distribution	70.00	12.00	2.40
32	PACIFICA SUB, Pacifica	Distribution	60.00	12.00	
33	PALMER SUB, Sisquat	Distribution	115.00	12.00	7.20
34	PANAMA SUB, Bakersfield	Distribution	70.00	21.00	7.20
35	PANOCHE SUB, Mendota	Transmission	230.00	12.00	7.20
36	PANORAMA SUB, Anderson	Distribution	115.00	12.00	
37	PARADISE SUB, Paradise	Distribution	60.00	12.00	7.20
38	PARADISE SUB, Paradise	Distribution	115.00	12.00	
39	PARKWAY SUB, Vallejo	Distribution	230.00	12.00	7.20
40	PARLIER SUB, Parlier	Distribution	115.00	12.00	7.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	PASO ROBLES SUB, Paso Robles	Distribution	70.00	12.00	2.40
2	PAUL SWEET SUB, Santa Cruz	Distribution	115.00	21.00	7.20
3	PEABODY SUB, Fairfield	Distribution	230.00	21.00	7.20
4	PEACHTON SUB, Gridley	Distribution	60.00	12.00	2.40
5	PEASE SUB, Tierra Buena	Transmission	115.00	12.00	
6	PENNGROVE SUB, Penngrove	Distribution	115.00	12.00	
7	PENRYN SUB, Penryn	Distribution	60.00	12.00	7.20
8	PEORIA SUB, Jamestown	Distribution	115.00	18.00	
9	PETALUMA C SUB, Petaluma	Distribution	60.00	12.00	
10	PIERCY SUB, San Jose	Distribution	115.00	21.00	7.20
11	PINE GROVE SUB, Pine Grove	Distribution	60.00	12.00	2.40
12	PINEDALE SUB, FRESNO	Distribution	115.00	21.00	7.20
13	PLACER SUB, Auburn	Transmission	115.00	12.00	
14	PLACERVILLE SUB, Placerville	Distribution	115.00	12.00	7.20
15	PLACERVILLE SUB, Placerville	Distribution	115.00	21.00	
16	PLAINFIELD SUB, Davis	Distribution	60.00	12.00	2.40
17	PLEASANT GROVE SUB, Pleasant Grove	Distribution	60.00	21.00	7.20
18	PLUMAS SUB, Wheatland	Distribution	60.00	21.00	7.20
19	PLUMAS SUB, Wheatland	Distribution	60.00	12.00	7.20
20	POINT MORETTI SUB, Davenport	Distribution	60.00	12.00	2.40
21	POINT PINOLE SUB, Richmond	Distribution	115.00	12.00	6.60
22	POSO MOUNTAIN SUB, Kern	Distribution	115.00	21.00	
23	PRUNEDALE SUB, Prunedale	Distribution	115.00	12.00	7.20
24	PUEBLO SUB, Napa	Distribution	115.00	12.00	
25	PUEBLO SUB, Napa	Distribution	115.00	21.00	
26	PURISIMA SUB, Lompoc	Distribution	115.00	12.00	7.20
27	PUTAH CREEK SUB, Winters	Distribution	115.00	12.00	
28	RACE TRACK SUB, Jamestown	Distribution	115.00	17.00	
29	RADUM SUB, Pleasanton	Distribution	60.00	12.00	
30	RAINBOW SUB, Sanger	Distribution	115.00	12.00	7.20
31	RALSTON SUB, Belmont	Distribution	60.00	12.00	
32	RANCHERS COTTON SUB, Fresno	Distribution	115.00	12.00	7.20
33	RAWSON SUB, Red Bluff	Distribution	60.00	12.00	2.40
34	RED BLUFF SUB, Red Bluff	Distribution	60.00	12.00	2.40
35	REDBUD SUB, Clearlake Oaks	Distribution	115.00	12.00	7.20
36	REDWOOD CITY SUB, Redwood City	Distribution	60.00	12.00	7.20
37	REEDLEY SUB, Reedley	Transmission	115.00	12.00	7.20
38	REEDLEY SUB, Reedley	Transmission	70.00	12.00	2.40
39	RENFRO SUB, BAKERSFIELD	Distribution	115.00	12.00	7.20
40	RESEARCH SUB, San Ramon	Distribution	230.00	21.00	7.20

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	RESERVATION ROAD SUB, Salinas	Distribution	60.00	12.00	2.40
2	RICE SUB, Princeton	Distribution	60.00	12.00	4.16
3	RICHMOND R SUB, Richmond	Distribution	115.00	12.00	7.20
4	RINCON SUB, Santa Rosa	Distribution	115.00	12.00	
5	RIO BRAVO SUB, Shafter	Distribution	115.00	12.00	7.20
6	RIO DELL SUB, Rio Dell	Distribution	60.00	12.00	
7	RIPON SUB, Ripon	Distribution	115.00	17.00	
8	RISING RIVER SUB, Cassell,	Distribution	60.00	12.00	2.40
9	RIVER OAKS SUB, San Jose	Distribution	115.00	21.00	7.20
10	RIVERBANK SUB, Escalon	Distribution	115.00	12.00	
11	ROB ROY SUB, Watsonville	Distribution	115.00	21.00	7.20
12	ROCKLIN SUB, Rocklin	Distribution	60.00	12.00	7.20
13	ROSEDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
14	ROSSMOOR SUB, Walnut Creek	Distribution	230.00	12.00	
15	ROUGH & READY ISLAND SUB, Stockton	Distribution	60.00	12.00	7.20
16	SALINAS SUB, Salinas	Transmission	115.00	12.00	7.20
17	SALMON CREEK SUB, Bodega Bay	Distribution	60.00	12.00	2.40
18	SAN ARDO SUB, San Ardo	Distribution	60.00	12.00	
19	SAN BENITO SUB, San Benito	Distribution	115.00	21.00	7.20
20	SAN BERNARD SUB, Lamont	Distribution	70.00	12.00	2.40
21	SAN CARLOS SUB, San Carlos	Distribution	60.00	12.00	7.20
22	SAN CARLOS SUB, San Carlos	Distribution	60.00	4.00	2.40
23	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	115.00	12.00	7.20
24	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	12.00	
25	SAN FRAN P-HUNTERS POINT SUB, San Francisco	Distribution	115.00	12.00	
26	SAN FRAN X (MISSION) SUB, San Francisco	Distribution	115.00	12.00	7.20
27	SAN FRAN Y (LARKIN) SUB, San Francisco	Distribution	115.00	12.00	7.20
28	SAN FRAN Z (Embarcadero), San Francisco	Distribution	230.00	34.50	7.20
29	SAN JOAQUIN SUB, San Joaquin	Distribution	70.00	12.00	7.20
30	SAN JOSE A SUB, San Jose	Distribution	115.00	4.00	7.20
31	SAN JOSE A SUB, San Jose	Distribution	115.00	12.00	
32	SAN JOSE B SUB, San Jose	Distribution	115.00	12.00	7.20
33	SAN LEANDRO U SUB, San Leandro	Distribution	115.00	12.00	
34	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	12.00	7.20
35	SAN MATEO SUB, San Mateo	Transmission	115.00	21.00	
36	SAN MATEO SUB, San Mateo	Transmission	60.00	4.00	
37	SAN MIGUEL SUB, San Miguel	Distribution	70.00	12.00	7.20
38	SAN PABLO SUB, Richmond	Distribution	115.00	12.00	7.20
39	SAN RAFAEL SUB, San Rafael	Distribution	115.00	12.00	
40	SAN RAMON SUB, San Ramon	Transmission	230.00	21.00	12.00

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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	SANGER SUB, Fresno	Transmission	115.00	12.00	7.20
2	SANTA MARIA SUB, Santa Maria	Distribution	115.00	12.00	7.20
3	SANTA NELLA SUB, Santa Nella	Distribution	70.00	12.00	2.40
4	SANTA RITA SUB, Dos Palos	Distribution	70.00	12.00	2.40
5	SANTA ROSA A SUB, Santa Rosa	Distribution	115.00	12.00	7.20
6	SANTA YNEZ SUB, Santa Maria	Distribution	115.00	12.00	7.20
7	SARATOGA SUB, Saratoga	Distribution	230.00	12.00	7.20
8	SAUSALITO SUB, Sausalito	Distribution	60.00	12.00	2.40
9	SAUSALITO SUB, Sausalito	Distribution	60.00	4.00	
10	SCHINDLER SUB, Five Points	Transmission	115.00	12.00	7.20
11	SEMITROPIC SUB, Wasco	Transmission	115.00	12.00	7.20
12	SERRAMONTE SUB, Daly City	Distribution	115.00	12.00	
13	SHAFTER SUB, Shafter	Distribution	115.00	12.00	7.20
14	SHARON SUB, Chowchilla	Distribution	115.00	12.00	
15	SHEPARD SUB, Clovis	Distribution	115.00	21.00	7.20
16	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	21.00	7.20
17	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	12.00	7.20
18	SHREDDER SUB, Redwood City	Distribution	115.00	4.00	6.60
19	SILVERADO SUB, St. Helena	Distribution	115.00	21.00	
20	SISQUOC SUB, Orcutt	Distribution	115.00	12.00	7.20
21	SMYRNA SUB, Wasco	Distribution	115.00	12.00	7.20
22	SNEATH LANE SUB, San Bruno	Distribution	60.00	12.00	2.40
23	SOBRANTE SUB, Orinda	Transmission	115.00	12.00	7.20
24	SOLEDAD SUB, Soledad	Transmission	60.00	12.00	
25	SONOMA A SUB, Sonoma	Distribution	115.00	12.00	
26	SOUTH BAY #1 & #2 SUB, Tracy	Distribution	60.00	4.00	
27	SPANISH CREEK SUB,	Distribution	60.00	44.00	
28	SPENCE SUB, Salinas	Distribution	60.00	12.00	
29	SRI SUB, Menlo Park	Distribution	60.00	12.00	
30	STAFFORD SUB, Novato	Distribution	60.00	12.00	
31	STAGG SUB, Stockton	Transmission	230.00	21.00	7.20
32	STAGG SUB, Stockton	Transmission	60.00	12.00	2.40
33	STELLING SUB, Cupertino	Distribution	115.00	12.00	7.20
34	STILLWATER STA SUB, Project City	Distribution	60.00	12.00	2.40
35	STOCKDALE SUB, Bakersfield	Distribution	230.00	21.00	7.20
36	STOCKDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
37	STOCKTON A SUB, Stockton	Distribution	115.00	12.00	
38	STOCKTON A SUB, Stockton	Distribution	60.00	4.00	
39	STONE CORRAL SUB, Woodlake	Distribution	70.00	12.00	2.40
40	STONE SUB, San Jose	Distribution	115.00	12.00	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	STOREY SUB, Madera	Distribution	230.00	12.00	7.20
2	STROUD SUB, Helm	Distribution	70.00	12.00	2.40
3	SUISUN SUB, Fairfield	Distribution	115.00	12.00	7.20
4	SUNOL SUB, Sunol	Distribution	60.00	12.00	7.20
5	SWIFT SUB, San Jose	Distribution	115.00	21.00	7.20
6	SYCAMORE CREEK SUB, Chico	Distribution	115.00	12.00	
7	TAFT SUB, Taft	Transmission	115.00	12.00	7.20
8	TAMARACK SUB, Soda Springs	Distribution	60.00	12.00	7.20
9	TASSAJARA SUB, Danville	Distribution	230.00	21.00	7.20
10	TEJON SUB, Leboc	Distribution	70.00	12.00	2.40
11	TEMBLOR SUB, McKittrick	Distribution	115.00	12.00	2.40
12	TEMPLETON SUB, TEMPLETON	Transmission	230.00	21.00	7.20
13	TEVIS SUB, Oildale	Distribution	115.00	21.00	7.20
14	TIDEWATER SUB, Martinez	Distribution	230.00	21.00	
15	TIVY VALLEY SUB, Fresno	Distribution	70.00	12.00	7.20
16	TRACY SUB, Tracy	Distribution	115.00	12.00	7.20
17	TRES VIAS SUB, Oroville	Distribution	60.00	12.00	7.20
18	TRIMBLE SUB, San Jose	Distribution	115.00	12.00	7.20
19	TRIMBLE SUB, San Jose	Distribution	115.00	21.00	7.20
20	TULARE LAKE SUB, Kettleman	Distribution	70.00	12.00	2.40
21	TULUCAY SUB, Napa	Transmission	60.00	12.00	7.20
22	TUPMAN SUB, Tupman	Distribution	115.00	12.00	7.20
23	TWISSELMAN SUB, Blackwell Corners	Distribution	70.00	12.00	7.20
24	TYLER SUB, Red Bluff	Distribution	60.00	12.00	2.40
25	UKIAH SUB, Ukiah	Distribution	115.00	12.00	7.20
26	URICH SUB, Martinez	Distribution	60.00	4.00	
27	VACA DIXON SUB, Vacaville	Transmission	115.00	12.00	7.20
28	VACAVILLE SUB, Vacaville	Distribution	115.00	12.00	7.20
29	VALLEY HOME SUB, Valley Home	Distribution	60.00	17.00	
30	VALLEY HOME SUB, Valley Home	Distribution	115.00	17.00	
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

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	60.00	12.00	7.20
5	WEBER SUB, Stockton	Transmission	230.00	12.00	7.20
6	WEEDPATCH SUB, Weedpatch	Distribution	70.00	12.00	7.20
7	WELLFIELD SUB, Lamont	Distribution	70.00	12.00	2.40
8	WEST FRESNO SUB, Fresno	Distribution	115.00	12.00	7.20
9	WEST LANE SUB, Stockton	Distribution	60.00	12.00	7.20
10	WEST SACRAMENTO SUB, WEST SACRAMENTO	Distribution	115.00	12.00	7.20
11	WESTLEY SUB, Westley	Distribution	60.00	12.00	2.40
12	WESTPARK SUB, Bakersfield	Distribution	115.00	12.00	7.20
13	WHEATLAND SUB, Wheatland	Distribution	60.00	12.00	7.20
14	WHEELER RIDGE SUB, Bakersfield	Transmission	70.00	12.00	7.20
15	WHISMAN SUB, Mt. View	Distribution	115.00	12.00	7.20
16	WILLIAMS SUB, Williams	Distribution	60.00	12.00	7.20
17	WILLITS A SUB, Willits	Distribution	60.00	12.00	2.40
18	WILLOW CREEK SUB, Willow Creek	Distribution	60.00	12.00	2.40
19	WILLOW PASS SUB, Pittsburg	Distribution	115.00	21.00	7.20
20	WILLOW PASS SUB, Pittsburg	Distribution	60.00	12.00	2.40
21	WILLOWS A SUB, Willows	Distribution	60.00	12.00	
22	WILSON SUB, Merced	Transmission	115.00	12.00	
23	WINDSOR SUB, Windsor	Distribution	60.00	12.00	
24	WINTERS SUB, Winters	Distribution	60.00	12.00	
25	WOLFE SUB, Cupertino	Distribution	115.00	12.00	
26	WOODCHUCK SUB, Wilson Village	Distribution	70.00	21.00	
27	WOODLAND SUB, Woodland	Distribution	115.00	12.00	7.20
28	WOODSIDE SUB, Woodside	Distribution	60.00	12.00	
29	WOODWARD SUB, Fresno	Distribution	115.00	21.00	7.20
30	WRIGHT SUB, Los Banos	Distribution	70.00	12.00	2.40
31	WYANDOTTE SUB, Oroville	Distribution	115.00	12.00	7.20
32	ZACA SUB, Santa Maria	Distribution	115.00	12.00	7.20
33	ZAMORA SUB, Zamora	Distribution	115.00	12.00	
34	Rounding issues in column f		-130.00		-37.20
35	Total Distribution and Transmission Substations		82020.00	18808.10	4052.36
36	Transmission only Substations		23890.00	10930.00	1342.20
37					
38	Combined Dist Subs < 10MVA (129 substations)				
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
360	6	1	2.00000			1
334	4	1	2.00000			2
840	2		2.00000			3
80	3		1.00000			4
400	2		Sync Cond	1	40	5
400	2		2.00000			6
90	3	1	1.00000			7
840	2		2.00000			8
90	3	1	1.00000			9
76	3		1.00000			10
190	4	1	2.00000			11
214	6	1	2.00000			12
120	6	2	2.00000			13
180	3	1	1.00000			14
400	2		2.00000			15
90	3	1	1.00000			16
200	1		1.00000			17
588	4	2	2.00000			18
400	2		2.00000			19
240	6	1	2.00000			20
400	2		2.00000			21
170	6	1	2.00000			22
68	3	1	1.00000			23
400	2		2.00000			24
840	2		2.00000			25
80	3	1	1.00000			26
600	2		2.00000			27
823	4	1	2.00000			28
117	3	1	1.00000			29
120	3		1.00000			30
1122	3	1	2.00000			31
255	4	1	2.00000			32
80	3		1.00000			33
840	2		2.00000			34
38	3		1.00000			35
134	3		1.00000			36
400	2		2.00000			37
180	3	1	1.00000			38
50	3	1	1.00000			39
1260	3		Sync Cond	2	80	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
40	1		1.00000			1
400	2		SVC	1	50	2
400	2		2.00000			3
823	4	1	2.00000			4
400	2		2.00000			5
90	3	1	1.00000			6
400	2		2.00000			7
1260	3		3.00000			8
90	3	1	1.00000			9
400	2		2.00000			10
840	2		2.00000			11
90	3		1.00000			12
400	2		2.00000			13
334	4		2.00000			14
840	3	1	1.00000			15
840	2		2.00000			16
100	1	1	2.00000			17
1243	5	1	Sync Cond	2	80	18
280	4	1	2.00000			19
90	3	1	1.00000			20
50	3		1.00000			21
840	2		2.00000			22
3366	9	2	3.00000			23
1630	10	1	4.00000			24
1260	3		3.00000			25
3364	9	2	3.00000			26
90	3		1.00000			27
400	2		2.00000			28
1260	3		1.00000			29
1243	5	1	3.00000			30
269	3	1	1.00000			31
1680	4		2.00000			32
1122	3	1	1.00000			33
200	4	1	1.00000			34
80	3		1.00000			35
1646	8	1	SVC	1	220	36
200	2		2.00000			37
168	3	1	1.00000			38
420	1		1.00000			39
840	2		2.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
80	3	1	1.00000			1
840	2		2.00000			2
95	3		1.00000			3
823	4	1	2.00000			4
190	4	1	2.00000			5
254	6		2.00000			6
1122	3	1	1.00000			7
200	2		2.00000			8
400	2		2.00000			9
420	1		1.00000			10
100	1		1.00000			11
823	4	1	2.00000			12
200	1		1.00000			13
200	2		2.00000			14
1260	3		Sync Cond	2	88	15
90	3	1	1.00000			16
30	3	1	1.00000			17
90	3	1	1.00000			18
90	3	1	1.00000			19
823	4	1	2.00000			20
75	6		2.00000			21
600	2		2.00000			22
1008	5	1	3.00000			23
1122	3	1	1.00000			24
162	4		2.00000			25
175	1		1.00000			26
806	6	1	2.00000			27
3366	9	2	3.00000			28
90	3	1	1.00000			29
400	2		2.00000			30
290	4	1	2.00000			31
1094	8		3.00000			32
2244	6	1	2.00000			33
334	4	1	2.00000			34
600	2		2.00000			35
60	3	1	1.00000			36
400	2		2.00000			37
689	4	1	2.00000			38
45	1		1.00000			39
90	2		2.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	
27	2		2.00000			1
13	1		1.00000			2
60	2		2.00000			3
41	2		2.00000			4
49	4	1	2.00000			5
30	1		1.00000			6
19	3	1	1.00000			7
16	1		1.00000			8
38	2		2.00000			9
16	1		1.00000			10
11	3	1	1.00000			11
16	1		1.00000			12
16	1		1.00000			13
27	4	1	2.00000			14
60	2		2.00000			15
13	3	1	1.00000			16
210	3		3.00000			17
30	1		1.00000			18
90	2		2.00000			19
25	2		2.00000			20
16	3	1	1.00000			21
16	1		1.00000			22
112	2		2.00000			23
45	1		1.00000			24
225	3		3.00000			25
13	1		1.00000			26
120	3		3.00000			27
39	4		2.00000			28
90	2		2.00000			29
75	2		2.00000			30
16	1		1.00000			31
13	1		1.00000			32
57	2		2.00000			33
57	3		3.00000			34
16	6	1	2.00000			35
70	3		3.00000			36
135	3		3.00000			37
16	2		2.00000			38
11	3	1	1.00000			39
15	3		1.00000			40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	3		1.00000			1
13	1		1.00000			2
13	3	1	1.00000			3
90	2		2.00000			4
13	1		1.00000			5
16	1		1.00000			6
30	1		1.00000			7
30	1		1.00000			8
225	3		3.00000			9
120	3		3.00000			10
90	3		3.00000			11
21	2		2.00000			12
76	3		3.00000			13
90	2		2.00000			14
45	1		1.00000			15
30	1		1.00000			16
46	2		2.00000			17
11	1		1.00000			18
20	3		1.00000			19
30	1		1.00000			20
15	3		1.00000			21
19	3		1.00000			22
135	3		3.00000			23
21	3	1	1.00000			24
16	1		1.00000			25
41	2		2.00000			26
90	2		2.00000			27
11	1		1.00000			28
6	3	1	1.00000			29
60	2		2.00000			30
24	1		1.00000			31
11	6		1.00000			32
37	3		2.00000			33
16	1		1.00000			34
16	1		1.00000			35
14	2		2.00000			36
25	2		2.00000			37
50	4		2.00000			38
45	1		1.00000			39
90	2		2.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
30	3	1	1.00000			1
39	4	1	2.00000			2
11	1		1.00000			3
45	1		1.00000			4
25	2		2.00000			5
13	1		1.00000			6
41	2		2.00000			7
16	1		1.00000			8
21	3	1	1.00000			9
32	2		2.00000			10
13	1		1.00000			11
13	1		1.00000			12
61	2		2.00000			13
11	3	1	1.00000			14
135	3		3.00000			15
29	2		2.00000			16
135	3		3.00000			17
16	1		1.00000			18
20	6	1	2.00000			19
19	3	1	1.00000			20
90	2		2.00000			21
45	1		1.00000			22
27	2		2.00000			23
21	3		1.00000			24
61	2		2.00000			25
59	3		3.00000			26
12	1		1.00000			27
21	6	1	2.00000			28
225	3		3.00000			29
42	3	1	1.00000			30
20	3	1	1.00000			31
28	4		2.00000			32
46	2		2.00000			33
45	1		1.00000			34
13	3	2	1.00000			35
58	10	3	2.00000			36
30	1		1.00000			37
43	2		2.00000			38
7	1		1.00000			39
29	6	1	2.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
130	3		3.00000			1
75	2		2.00000			2
35	3		3.00000			3
7	1		1.00000			4
30	1		1.00000			5
90	2		2.00000			6
19	3	1	1.00000			7
16	3		1.00000			8
16	1		1.00000			9
60	2		2.00000			10
135	3		3.00000			11
135	3		3.00000			12
90	2		2.00000			13
75	2		2.00000			14
16	1		1.00000			15
75	2		2.00000			16
14	1		1.00000			17
43	2		2.00000			18
61	2		2.00000			19
60	2		2.00000			20
11	3	1	1.00000			21
30	1		1.00000			22
135	3		3.00000			23
75	2		2.00000			24
11	1		1.00000			25
13	1		1.00000			26
105	3		3.00000			27
32	6	1	2.00000			28
180	4		4.00000			29
25	2	1	2.00000			30
16	1		1.00000			31
16	1		1.00000			32
8	1		1.00000			33
135	3		3.00000			34
45	1		1.00000			35
90	2		2.00000			36
25	4		2.00000			37
90	2		2.00000			38
63	2		2.00000			39
45	1		1.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
127	3		3.00000			1
32	2		2.00000			2
180	4		4.00000			3
23	2		2.00000			4
11	1		1.00000			5
13	1		1.00000			6
11	3	1	1.00000			7
13	1		1.00000			8
21	3	1	1.00000			9
90	2	1	2.00000			10
13	1		1.00000			11
50	3		1.00000			12
60	2		2.00000			13
30	1		1.00000			14
60	2		2.00000			15
225	3		3.00000			16
30	1		1.00000			17
22	2		2.00000			18
30	3		1.00000			19
50	2		2.00000			20
11	1		1.00000			21
21	3	1	1.00000			22
60	2		2.00000			23
45	1		1.00000			24
19	3	1	1.00000			25
60	2		2.00000			26
105	3		3.00000			27
32	2		2.00000			28
25	4		2.00000			29
49	4	1	2.00000			30
60	2		2.00000			31
16	1		1.00000			32
25	1		1.00000			33
13	1		1.00000			34
16	1		1.00000			35
21	3	1	SVC	1	15	36
45	1		1.00000			37
19	3		1.00000			38
22	4		2.00000			39
19	3		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
16	1		1.00000			1
30	1		1.00000			2
32	2		2.00000			3
7	1		1.00000			4
16	1		1.00000			5
22	2		2.00000			6
27	2		2.00000			7
81	3		3.00000			8
90	2		2.00000			9
19	3	1	1.00000			10
60	2		2.00000			11
32	2		2.00000			12
12	7	1	2.00000			13
60	2		2.00000			14
21	3		3.00000			15
50	5		3.00000			16
90	3		3.00000			17
16	1		1.00000			18
13	2		2.00000			19
12	1		1.00000			20
29	2		2.00000			21
60	2		2.00000			22
19	2		2.00000			23
16	3		1.00000			24
46	2		2.00000			25
13	1		1.00000			26
150	2		2.00000			27
90	2		2.00000			28
77	3		3.00000			29
60	2		2.00000			30
90	2		2.00000			31
70	2		2.00000			32
25	1		1.00000			33
16	1		1.00000			34
13	3	1	1.00000			35
90	2		2.00000			36
16	1		1.00000			37
133	6		2.00000			38
77	3		2.00000			39
11	1		1.00000			40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
4	1		1.00000			1
4	1		1.00000			2
20	3		1.00000			3
46	2		2.00000			4
16	1		1.00000			5
13	1		1.00000			6
16	1		1.00000			7
29	2		2.00000			8
90	2		2.00000			9
39	2		2.00000			10
105	3		3.00000			11
22	1		1.00000			12
27	2		2.00000			13
30	1		1.00000			14
60	2		2.00000			15
135	3		3.00000			16
90	2		2.00000			17
11	3	1	1.00000			18
11	3		1.00000			19
47	3		3.00000			20
90	2		2.00000			21
135	3		3.00000			22
23	2		2.00000			23
49	4		2.00000			24
75	2		2.00000			25
215	4		4.00000			26
25	3	1	1.00000			27
90	2		2.00000			28
75	2		2.00000			29
76	3		3.00000			30
30	1		1.00000			31
165	3		3.00000			32
14	2		2.00000			33
145	5	1	3.00000			34
45	1		1.00000			35
75	2		2.00000			36
90	2		2.00000			37
91	3		3.00000			38
21	3	1	1.00000			39
27	2		2.00000			40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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)	
25	6		2.00000			1
45	1		1.00000			2
11	3		1.00000			3
100	3		3.00000			4
30	1	1	1.00000			5
90	2		2.00000			6
46	2		2.00000			7
21	3	1	1.00000			8
5	3	1	1.00000			9
45	1		1.00000			10
45	1		1.00000			11
51	3		3.00000			12
13	3	1	1.00000			13
32	2		2.00000			14
13	3	1	1.00000			15
43	2		2.00000			16
21	3	1	1.00000			17
5	3	1	1.00000			18
29	2		2.00000			19
19	3		1.00000			20
45	1		1.00000			21
71	7		3.00000			22
30	1		1.00000			23
21	2		2.00000			24
45	1		1.00000			25
45	1		1.00000			26
105	3		3.00000			27
135	3		3.00000			28
135	8	1	4.00000			29
11	3		1.00000			30
32	2		2.00000			31
13	3	1	1.00000			32
49	4	1	2.00000			33
43	4	1	2.00000			34
11	3	1	1.00000			35
90	2		2.00000			36
21	2		2.00000			37
32	2		2.00000			38
105	3		3.00000			39
13	4	1	1.00000			40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	1		1.00000			1
170	3		3.00000			2
5	3	1	1.00000			3
30	1		1.00000			4
32	2		2.00000			5
18	2		2.00000			6
45	1		1.00000			7
45	1		1.00000			8
21	3	1	1.00000			9
45	1		1.00000			10
11	1		1.00000			11
34	4	1	2.00000			12
43	2		2.00000			13
60	2		2.00000			14
6	3	1	1.00000			15
90	2		2.00000			16
75	2		2.00000			17
11	1		1.00000			18
14	3	1	1.00000			19
43	2		2.00000			20
90	2		2.00000			21
45	1		1.00000			22
135	3		3.00000			23
29	2		2.00000			24
11	3	1	1.00000			25
45	1		1.00000			26
120	3		3.00000			27
30	1		1.00000			28
16	1		1.00000			29
105	3		3.00000			30
115	3		2.00000			31
135	3		2.00000			32
16	1		1.00000			33
79	5		3.00000			34
30	1		1.00000			35
150	2		2.00000			36
90	2		2.00000			37
20	4	1	2.00000			38
29	2		2.00000			39
41	4		2.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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.
16	1		1.00000			1
32	2		2.00000			2
90	2		2.00000			3
45	1		1.00000			4
90	2		2.00000			5
45	1		1.00000			6
23	2		2.00000			7
43	3		2.00000			8
195	4		4.00000			9
175	4		4.00000			10
120	3		3.00000			11
38	3	1	1.00000			12
135	3		3.00000			13
90	3		3.00000			14
90	2		2.00000			15
42	6	1	2.00000			16
31	4		2.00000			17
16	1		1.00000			18
45	1		1.00000			19
18	4		2.00000			20
60	2		2.00000			21
16	1		1.00000			22
6	3		1.00000			23
25	7		2.00000			24
11	1		1.00000			25
22	3		1.00000			26
45	1		1.00000			27
41	2		2.00000			28
25	2		2.00000			29
5	3	1	1.00000			30
16	1		1.00000			31
23	2		2.00000			32
11	1		1.00000			33
45	1		1.00000			34
30	1		1.00000			35
30	1		1.00000			36
45	1		1.00000			37
45	1		1.00000			38
30	1		1.00000			39
45	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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	3		3.00000			1
135	3		SVC	1	60	2
195	3		3.00000			3
14	6	1	2.00000			4
50	2		2.00000			5
13	1		1.00000			6
61	2		2.00000			7
58	4		2.00000			8
57	5	1	3.00000			9
45	1		1.00000			10
22	4		2.00000			11
135	3		3.00000			12
41	4	1	2.00000			13
30	1		1.00000			14
30	1		1.00000			15
39	2		2.00000			16
135	3		3.00000			17
45	1		1.00000			18
13	1		1.00000			19
11	1		1.00000			20
16	1		1.00000			21
65	2		1.00000			22
32	2		2.00000			23
45	1		StatCom	2	8	24
45	1		1.00000			25
11	1		1.00000			26
32	2		2.00000			27
16	1		1.00000			28
25	6		2.00000			29
30	1		1.00000			30
16	4		2.00000			31
16	1		1.00000			32
19	3		1.00000			33
50	5		3.00000			34
23	3		2.00000			35
70	5		3.00000			36
30	1		1.00000			37
30	1		1.00000			38
90	2		2.00000			39
45	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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)	
11	1		1.00000			1
14	2		2.00000			2
90	2		2.00000			3
32	2		2.00000			4
64	4		2.00000			5
11	3		1.00000			6
73	2		2.00000			7
11	3	1	1.00000			8
90	2		2.00000			9
73	4	1	2.00000			10
23	1		1.00000			11
27	4	1	2.00000			12
30	1		1.00000			13
90	2		2.00000			14
16	1		1.00000			15
90	2		2.00000			16
11	3	1	1.00000			17
11	3	1	1.00000			18
30	1		1.00000			19
19	3		1.00000			20
29	2		2.00000			21
12	3	1	1.00000			22
186	3		3.00000			23
180	4		4.00000			24
98	2		2.00000			25
375	5		5.00000			26
450	6		6.00000			27
565	4		4.00000			28
18	2		2.00000			29
40	2		3.00000			30
30	1		1.00000			31
180	4		2.00000			32
160	4		4.00000			33
135	3		3.00000			34
45	1		1.00000			35
13	3	1	1.00000			36
16	1		1.00000			37
45	1		1.00000			38
120	3		3.00000			39
300	4		4.00000			40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/25/2020	Year/Period of Report End of 2019/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.
60	2		2.00000			1
90	2		2.00000			2
27	2		2.00000			3
12	3		1.00000			4
135	3		3.00000			5
41	2		2.00000			6
157	3		3.00000			7
21	3	1	1.00000			8
5	3	1	1.00000			9
60	2		2.00000			10
30	1		1.00000			11
13	1		1.00000			12
90	2		2.00000			13
11	1		1.00000			14
45	1		1.00000			15
61	2		2.00000			16
16	1		1.00000			17
15	3	1	1.00000			18
60	2		2.00000			19
32	2		2.00000			20
49	4		2.00000			21
19	6		2.00000			22
30	1		1.00000			23
11	1		1.00000			24
60	2		2.00000			25
25	3		3.00000			26
19	1		1.00000			27
40	4	1	2.00000			28
13	1		1.00000			29
25	2		2.00000			30
150	2		2.00000			31
51	4	1	2.00000			32
105	3		2.00000			33
11	3	1	1.00000			34
225	3		3.00000			35
75	2		2.00000			36
105	3		3.00000			37
22	6		1.00000			38
17	2		2.00000			39
45	1		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
90	2		2.00000			1
21	3	1	1.00000			2
120	3		3.00000			3
13	1		1.00000			4
135	3		3.00000			5
90	3		3.00000			6
27	2		2.00000			7
13	1		1.00000			8
225	3		3.00000			9
49	4		2.00000			10
21	3	1	1.00000			11
90	2		2.00000			12
90	2		2.00000			13
150	2		2.00000			14
13	1		1.00000			15
121	4		4.00000			16
16	1		1.00000			17
90	2		2.00000			18
90	2		2.00000			19
24	4	2	2.00000			20
30	1		1.00000			21
61	2		2.00000			22
32	2		2.00000			23
19	4		2.00000			24
29	2		2.00000			25
10	3	1	1.00000			26
105	3		3.00000			27
120	3		3.00000			28
6	3	1	1.00000			29
30	1		1.00000			30
29	2		2.00000			31
17	6		2.00000			32
90	2		4.00000			33
30	1		1.00000			34
60	2		2.00000			35
90	2		2.00000			36
150	2	1	2.00000			37
21	3	1	1.00000			38
60	2		2.00000			39
20	3		1.00000			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/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		1.00000			1
16	1		1.00000			2
8	1		1.00000			3
50	2		2.00000			4
90	2		2.00000			5
30	1		1.00000			6
24	4		2.00000			7
135	3		3.00000			8
30	1		1.00000			9
105	3		3.00000			10
29	2		2.00000			11
105	3		3.00000			12
44	4	1	2.00000			13
30	1		1.00000			14
105	3		3.00000			15
27	2		2.00000			16
19	3	1	1.00000			17
13	3	1	1.00000			18
30	1		1.00000			19
11	3	1	1.00000			20
14	3	1	1.00000			21
14	1		1.00000			22
30	1		1.00000			23
13	1		1.00000			24
120	3		3.00000			25
23	3		1.00000			26
135	3		3.00000			27
60	2		2.00000			28
135	3		3.00000			29
13	1		1.00000			30
120	3		3.00000			31
11	1		1.00000			32
27	2		2.00000			33
-53						34
96800	1770	158		13	641	35
65245	392	62				36
						37
675	331	53				38
						39
						40

Schedule Page: 426.3 Line No.: 28 Column: e

Note (1):

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.

Schedule Page: 426.3 Line No.: 34 Column: e

Note (1):

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.

Schedule Page: 426.4 Line No.: 26 Column: e

Note (1):

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.

Schedule Page: 426.5 Line No.: 16 Column: e

Note (1):

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.

Schedule Page: 426.8 Line No.: 16 Column: e

Note (1):

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.

Schedule Page: 426.9 Line No.: 8 Column: e

Note (1):

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.

Schedule Page: 426.9 Line No.: 24 Column: e

Note (1):

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.

Schedule Page: 426.10 Line No.: 21 Column: c

Note (3):

Any substation that has a transmission-to-transmission transformation (Primary voltage >=60kV and secondary voltage >= 60kV) is defined as a transmission station, regardless of the number of distribution assets in the station. Hence, substations with both transmission and distribution (secondary voltage <60 kV) transformers are characterized as Transmission in the list. There are 59 Transmission Substations with both transmission and distribution transformers; one of them <10MVA. There are 664 substations with distribution transformer banks. (605+59 = 664)

Schedule Page: 426.12 Line No.: 19 Column: c

Note (3):

Any substation that has a transmission-to-transmission transformation (Primary voltage >=60kV and secondary voltage >= 60kV) is defined as a transmission station, regardless of the number of distribution assets in the station. Hence, substations with both transmission and distribution (secondary voltage <60 kV) transformers are characterized as Transmission in the list. There are 59 Transmission Substations with both transmission and distribution transformers; one of them <10MVA. There are 664 substations with distribution transformer banks. (605+59 = 664)

Schedule Page: 426.13 Line No.: 1 Column: e

Note (1):

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.

Schedule Page: 426.13 Line No.: 16 Column: e

Note (1):

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.

Schedule Page: 426.16 Line No.: 10 Column: e

Note (1):

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.

Schedule Page: 426.17 Line No.: 34 Column: a

Schedule Page: 426.17 Line No.: 36 Column: 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	03/25/2020	End of 2019/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	Wildfire Compliance Advice		426.5	2,818
4	Corporate A&G Allocations		923.0, 426.5	106,754,795
5	Total - Administrative & General Expenses			106,757,613
6				
7		Eureka Energy Company		
8	Rent Expense		532.0	321,288
9				
10	Total Non-power Goods/Srv.provided by Affiliats			107,078,901
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			568,728
23	ADMINISTRATION			467,206
24	AFFILIATE RULES COMPLIANCE SUPPORT			25,738
25	BANKING SERVICES			36,027
26	BOD EXPENSES			126
27	BUSINESS PLANNING SERVICES			28,029
28	COMPLIANCE & ETHICS SUPPORT			8,443
29	CONSULTING SERVICES			5,997
30	CORPORATE SECRETARY SUPPORT			1,999
31	CORPORATE SUSTAINABILITY SUPPORT			258,285
32	FINANCIAL FORECASTING AND ANALYSIS			60,363
33	FLEET SERVICES			6,765
34	HUMAN RESOURCES SUPPORT			76,744
35	INFORMATION TECHNOLOGY			471,412
36	INSURANCE SUPPORT			9,729
37	INTERNAL AUDIT SERVICES			6,362
38	INVESTOR RELATIONS SUPPORT			10,393
39	LEGAL			62,478
40	MISC EXPENSE			3,767
41	REAL ESTATE AND FACILITY			493,004
42	SECURITY SUPPORT			347,316
1	**Non-power Goods or Services Provided by Affiliated**			
2				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	03/25/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	SOURCING SUPPORT			129,925
23	STRATEGY SUPPORT			200
24	STRATEGIC ANALYSIS SUPPORT			50,315
25	TAX SERVICES			94,853
26	INTEREST			337,504
27	EMPLOYEE TRANSFER FEE			276,450
28				
29	Total - A&G Direct Charges to PG&E Corp			3,838,158
30				
31		FUELCO	930.2	
32	ACCOUNTING			19,088
33	CFO SUPPORT			6,362
34	FUEL PURCHASING SUPPORT			465,068
35	SUPPLY CHAIN SUPPORT			9,581
36				
37	Total - A&G Direct Charges to FUELCO			500,099
38				
39				
40				
41				
42	TOTAL NON-POWER GOODS/SRV PROVIDED FOR			4,338,257

Schedule Page: 429 Line No.: 4 Column: a

NOTE:

The 2019 Corporation's A&G Allocation Rate is calculated below and will be rounded up to 99% (Three-Factor Methodology and Headcount).

(A) 3-Factor Method, 99.98%

Simple Average of the following ratios:

(a) Affiliate Assets/Total Consolidated Assets

(b) Affiliate Operating Expenses less Fuel purchase costs/Total Consolidated Operating Expenses less Fuel Purchase Costs

(c) Affiliate Headcount/Total Consolidated Headcount

(B) Capitalization, 100%

Affiliate Capitalization/Total Consolidated Capitalization

(C) Headcount, 99.98%

It is the ratio of affiliate's headcount over total headcount for all entities.

All Corporation's cost centers allocate its charges based on Three Factor Methodology, except for the following cost centers.

COST CENTER	Description	Allocation Approach
PCC 20036	HOLD-Banking & Money Management	Capitalization
PCC 20039	HOLD-Investments & Benefits	Headcount
PCC 20041	HOLD- Investor Relations	Capitalization
PCC 20050	HOLD - Senior VP Human Resource	Headcount

SELECTED FINANCIAL DATA - CLASS A, B, C, AND D ELECTRIC UTILITIES
PACIFIC GAS AND ELECTRIC COMPANY
PERSON RESPONSIBLE FOR THIS REPORT: David Thomason, Vice President, CFO and Controller
(PREPARED FROM INFORMATION IN THE 2019 FERC ANNUAL REPORTS)

	December 31		
	2018	2019	Annual Average
NET ELECTRIC PLANT INVESTMENT (a)			
Electric Utility Plant (California Only)			
1. Intangible Plant	$ 1,175,290,465	$ 1,180,995,855	$ 1,178,143,160
2. Land and Land Rights	619,118,606	624,175,634	621,647,120
3. Depreciable Plant	63,715,146,687	67,239,111,217	65,477,128,952
4. Nuclear Fuel	3,021,329,381	3,099,071,385	3,060,200,383
5. Gross Electric Utility Plant	68,530,885,139	72,143,354,091	70,337,119,615
6. Electric Plant Held for Future Use - Net	0	0	0
7. Construction Work in Progress - Electric	2,036,528,656	2,278,121,533	2,157,325,095
8. Accumulated Deferred Income Taxes	3,071,841,583	7,445,591,597	5,258,716,590
9. Less: Reserves for Depreciation - Electric Utility Plant	28,007,928,482	29,566,029,119	28,786,978,801
10. Less: Amortization and Depletion Reserves	3,310,263,101	3,471,973,667	3,391,118,384
11. Less: Customer Advances and Contribution in Aid of Construction	232,497,053	229,861,025	231,179,039
12. Less: Accumulated Deferred Income and Investment Tax Credits	5,415,765,761	6,953,898,868	6,184,832,314
13. Material and Supplies - Electric Only	287,755,886	356,607,340	322,181,613
14. Net Electric Plant Investment	$ 36,960,556,867	$ 42,001,911,882	$ 39,481,234,375
CAPITALIZATION (Total Company)			
15. Common Stock	$ 1,321,874,045	$ 1,321,874,045	$ 1,321,874,045
16. Capital Stock (Premium, Discount and Expense)-Net	1,769,325,445	1,769,325,445	1,769,325,445
17. Other Paid in Capital	6,780,547,928	6,780,547,928	6,780,547,928
18. Retained Earnings	2,825,438,368	(4,794,324,809)	(984,443,221)
19. Other Miscellaneous Capital Accounts	0	0	0
20. Common Stock and Equity (Lines 15 through 19)	12,697,185,786	5,077,422,609	8,887,304,197
21. Preferred Stock	257,994,575	257,994,575	257,994,575
22. Long-Term Debt	18,323,995,622	19,887,100,000	19,105,547,811
23. Notes Payable and Current Portion of Long-Term Debt	3,135,000,001	3,138,570,758	3,136,785,380
24. Total Capitalization (Lines 20 through 23)	$ 34,414,175,984	$ 28,361,087,942	$ 31,387,631,963

-

(a) Includes Common Plant Allocations.

PACIFIC GAS AND ELECTRIC COMPANY
INCOME STATEMENT DATA
FOR CALIFORNIA INTRASTATE ELECTRIC OPERATIONS ONLY (b)

	Annual Amount
25. Operating Revenues	12,776,870,034
26. Operating and Maintenance Expense	19,053,771,334
27. Depreciation	2,007,521,729
28. Depreciation for Asset Retirement Costs	-
29. Amortization and Depletion Expenses and Property Losses	197,916,043
30. Regulatory Debits	2,344
31. Regulatory Credits	-
32. Property Taxes (Ad Valorem)	320,765,747
33. Taxes Other than Income and Property Taxes	126,433,536
34. Operating Revenue Deductions (Before Federal and California Income Taxes)	21,706,410,733
35. Federal and California Income Taxes - Net	(3,345,991,761)
36. Gains and Losses from Disposition of Electric Plant - Net	(5,958,154)
37. Accretion Expense	-
38. Total Utility Operating Expenses	18,354,460,818
39. Net Operating Income (California Intrastate Electric Operations Only)	(5,577,590,784)
OTHER INCOME AND EXPENSE (Total Company)	
40. Net Operating Income from Other Utility Operations (Total)	(735,549,903)
41. Net Other Income and Deductions	(302,929,380)
42. Income Before Interest Charges	(6,616,070,067)
43. Interest Charges	1,005,697,606
44. Income Before Extraordinary Items	(7,621,767,673)
45. Extraordinary Items - Net of Income Tax	-
46. Net Income	(7,621,767,673)
47. Preferred Stock Dividends and Redemption Premium	-
48. Income Available for Common Stock	$ (7,621,767,673)
49. Common Stock Dividends	-
OTHER DATA (CALIFORNIA INTRASTATE ELECTRIC OPERATIONS ONLY) (b) Items (48-50)	
50. Payroll Charged to Operating and Maintenance Expense	$ 1,359,642,693
51. Payroll Capitalized to Utility Plant - Electric	872,097,528
52.Total Payroll	$ 2,231,740,221
53. Purchased Power	$ 4,058,377,103
54. Allowance for Funds Used During Construction	$ 114,331,019
55. Interdepartmental Revenues	$ 48,794,887
56. Interdepartmental Expenses	$ 76,101,792
57. Revenue from Sales to Residential Customers	$ 4,846,946,484
58. Residential Sales in Kwhs	27,513,436,000
59. Total Revenue Sales to Ultimate Customers	$ 12,319,651,940
60. Kwhs Sold to Ultimate Customers	78,372,216,000
61. Average Number of Residential Customers	4,845,484
62. Average Number of Ultimate Customers	5,524,081

(b) Assumes CPUC Jurisdictional Portion of Electric Operations.