



PG&E Corporation
Pacific Gas and Electric Company

2019 Joint Annual Report to Shareholders

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Notice: This 2019 Joint Annual Report to Shareholders (this “Annual Report”) includes PG&E Corporation and Pacific Gas and Electric Company’s joint Annual Report on Form 10-K for the year ended December 31, 2019 that was filed with the Securities and Exchange Commission on February 18, 2020 (the “Form 10-K”).

Financial Highlights⁽¹⁾

PG&E Corporation

| <i>(unaudited, in millions, except share and per share amounts)</i> | | 2019 | 2018 |
|--|----|--------------------|--------------------|
| Operating Revenues | \$ | 17,129 | \$ 16,759 |
| Income (Loss) Available for Common Shareholders | | | |
| PG&E Corporation's Loss on a GAAP basis | | (7,656) | (6,851) |
| Non-core items: ⁽²⁾ | | | |
| Wildfire-related costs ⁽³⁾ | | 8,761 | 8,914 |
| Electric asset inspections costs ⁽⁴⁾ | | 557 | — |
| Locate and mark penalty ⁽⁵⁾ | | 39 | — |
| Chapter 11-related costs ⁽⁶⁾ | | 180 | — |
| 2019 GT&S capital disallowance ⁽⁷⁾ | | 193 | — |
| Pipeline-related expenses ⁽⁸⁾ | | — | 33 |
| Reduction in gas-related capital disallowances ⁽⁹⁾ | | — | (27) |
| PG&E Corporation's Non-GAAP Core Earnings⁽¹⁰⁾ | | 2,074 | 2,069 |
| Income (Loss) Per Common Share, diluted | | | |
| PG&E Corporation's Loss per Common Share on a GAAP basis | | (14.50) | (13.25) |
| Non-core items: ⁽²⁾ | | | |
| Wildfire-related costs ⁽³⁾ | | 16.59 | 17.24 |
| Electric asset inspections costs ⁽⁴⁾ | | 1.05 | — |
| Locate and mark penalty ⁽⁵⁾ | | 0.07 | — |
| Chapter 11-related costs ⁽⁶⁾ | | 0.34 | — |
| 2019 GT&S capital disallowance ⁽⁷⁾ | | 0.37 | — |
| Pipeline-related expenses ⁽⁸⁾ | | — | 0.06 |
| Reduction in gas-related capital disallowances ⁽⁹⁾ | | — | (0.05) |
| PG&E Corporation's Non-GAAP Core Earnings per Common Share⁽¹⁰⁾ | | 3.93 | 4.00 |
| Dividends Declared Per Common Share | | — | — |
| Total Assets at December 31 | \$ | 85,196 | \$ 76,995 |
| Number of common shares outstanding at December 31 | | 529,236,741 | 520,338,710 |

(1) This is a combined annual report of PG&E Corporation and Pacific Gas and Electric Company (the "Utility"). PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and subsidiaries, and have been prepared in accordance with Generally Accepted Accounting Principles ("GAAP"). All amounts presented in the table above are tax-adjusted at PG&E Corporation's statutory tax rate of 27.98%, except for certain Wildfire-related, Chapter 11-related, and 2019 GT&S capital disallowance costs, which are not tax deductible. Amounts may not sum due to rounding.

(2) "Non-core Items" include items that management does not consider representative of ongoing earnings and affect comparability of financial results between periods, consisting of the items listed in the table above.

(3) The Utility incurred costs of \$12.2 billion (before the tax impact of \$3.4 billion) during the year ended December 31, 2019, associated with wildfire-related costs. This includes accrued charges of \$11.4 billion (before the tax impact of \$3.2 billion) during the year ended December 31, 2019, related to increases in the recorded liability for third-party claims related to the 2018 Camp Fire, the 2017 Northern California wildfires, and the 2015 Butte fire. The Utility incurred costs of \$278 million (before the tax impact of \$78 million) during the year ended December 31, 2019, for clean-up and repair costs. The Utility also incurred costs of \$152 million (before the tax impact of \$43 million) during the year ended December 31, 2019, for legal and other costs. In addition, the Utility incurred costs of \$398 million (before the tax impact of \$108 million) during the year ended December 31, 2019 related to the Wildfire Order Instituting Investigation ("OII") settlement. The Utility also recorded a charge of \$86 million (before the tax impact of \$24 million) during the year ended December 31, 2019 related to a one-time bill credit for customers impacted by the October 9, 2019 Public Safety Power Shutoff (PSPS) event. These costs were partially offset by \$189 million (before the tax impact of \$53 million) recorded during the year ended December 31, 2019 for probable cost recoveries of insurance premiums incurred in 2018 above amounts included in authorized revenue requirements.

(4) The Utility incurred costs of \$773 million (before the tax impact of \$216 million) during the year ended December 31, 2019, for incremental operating expenses related to enhanced and accelerated inspections of electric transmission and distribution assets, and resulting repairs that are not probable of recovery.

(5) The Utility recorded costs of \$39 million (not tax deductible) during the year ended December 31, 2019 associated with an incremental fine payable to the State General Fund resulting from a presiding officer's decision in the Locate and Mark OII.

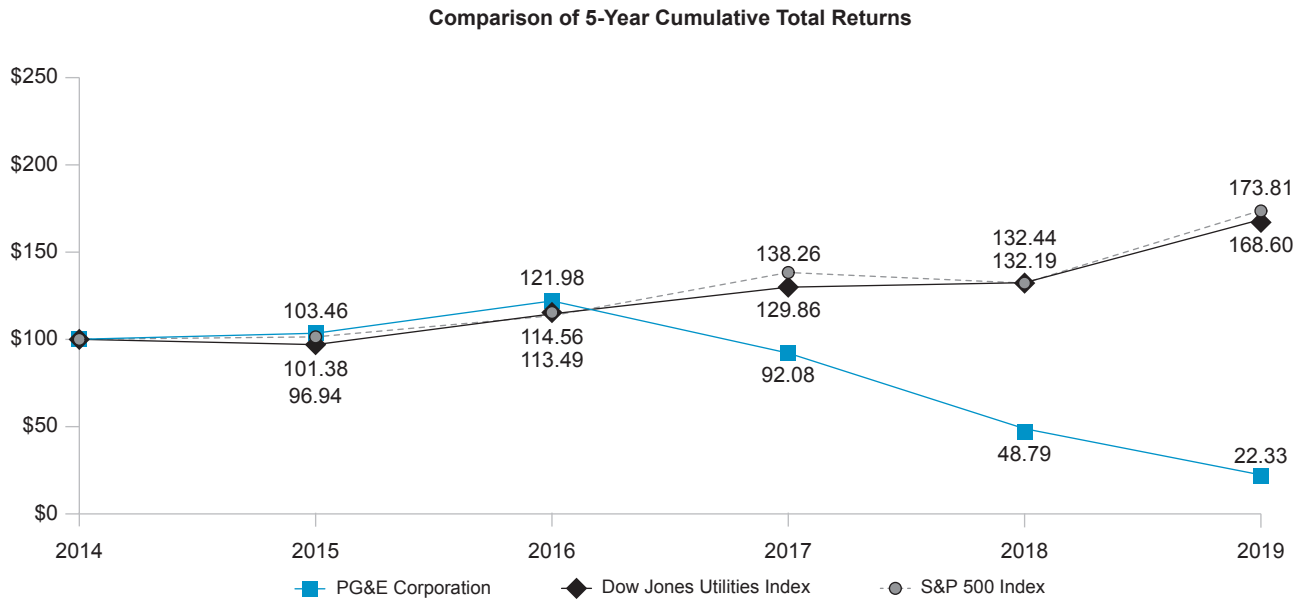
- (6) PG&E Corporation and the Utility incurred costs of \$199 million (before the tax impact of \$19 million) during the year ended December 31, 2019, directly associated with their Chapter 11 Cases. This includes legal and other costs of \$292 million (before the tax impact of \$45 million) during the year ended December 31, 2019, (\$129 million of legal and other costs during the year ended December 31, 2019, are not tax deductible). The Utility also incurred \$114 million (before the tax impact of \$32 million) during the year ended December 31, 2019 for debtor-in-possession (“DIP”) financing costs. These costs were partially offset by a reduction to interest expense on pre-petition debt of \$146 million (before the tax impact of \$41 million) during the year ended December 31, 2019, and interest income of \$60 million (before the tax impact of \$17 million) recorded during the year months ended December 31, 2019.
- (7) The Utility recorded costs of \$237 million (before the tax impact of \$44 million) during the year ended December 31, 2019 for pipeline-replacement costs disallowed in the 2019 GT&S rate case as a result of spending above amounts authorized in the 2015-2018 rate case period. Due to flow-through treatment related to deductible repairs, \$80 million of the loss does not generate a net tax benefit.
- (8) The Utility incurred costs of \$46 million (before the tax impact of \$13 million) during the year ended December 31, 2018, for pipeline-related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.
- (9) The Utility reduced the estimated disallowance for gas-related capital costs that were expected to exceed authorized amounts by \$38 million (before the tax impact of \$11 million) during the year ended December 31, 2018. The Utility had previously recorded \$85 million (before the tax impact of \$35 million) in 2016 for probable capital disallowances in the 2015 GT&S rate case. From 2012 through 2014, the Utility had recorded cumulative charges of \$665 million (before the tax impact of \$271 million) for disallowed Pipeline Safety Enhancement Plan-related capital expenditures.
- (10) “Non-GAAP core earnings” is a non-GAAP financial measure and is calculated as income available for common shareholders less items non-core items. “Non-core items” include items that management does not consider representative of ongoing earnings and affect comparability of financial results between periods, consisting of the items listed in the table above. “Non-GAAP core EPS”, also referred to as “non-GAAP core earnings per share”, is a non-GAAP financial measure and is calculated as non-GAAP core earnings divided by common shares outstanding (diluted). PG&E Corporation and the Utility use non-GAAP core earnings and non-GAAP core EPS to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating planning, and employee incentive compensation. PG&E Corporation and the Utility believe that non-GAAP core earnings and non-GAAP core EPS provide additional insight into the underlying trends of the business, allowing for a better comparison against historical results and expectations for future performance.

Non-GAAP core earnings and non-GAAP core EPS are not substitutes or alternatives for GAAP measures such as consolidated income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

Comparison of Five-Year Cumulative Total Shareholder Return⁽¹⁾

PG&E Corporation common stock is traded on the New York Stock Exchange under the symbol "PCG."

This graph compares the cumulative total return on PG&E Corporation common stock (equal to dividends plus stock price appreciation) during the past five fiscal years with that of the Standard & Poor's 500 Stock Index and the Dow Jones Utilities Index.



(1) Assumes \$100 invested on December 31, 2014 in PG&E Corporation common stock, the Standard & Poor's 500 Stock Index, and the Dow Jones Utilities Index, and assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2019

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from **to**

| Commission File Number | Exact Name of Registrant as Specified In Its Charter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|-----------------------------------|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |



PG&E Corporation

**77 Beale Street
P.O. Box 770000**

San Francisco, California 94117
(Address of principal executive offices) (Zip Code)
415 973-1000
(Registrant's telephone number, including area code)



***Pacific Gas and
Electric Company***

**77 Beale Street
P.O. Box 770000**

San Francisco, California 94117
(Address of principal executive offices) (Zip Code)
415 973-1000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

| Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|--|-------------------|---|
| Common stock, no par value | PCG | The New York Stock Exchange |
| First preferred stock, cumulative, par value \$25 per share, 5% series A redeemable | PCG-PE | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 5% redeemable | PCG-PD | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 4.80% redeemable | PCG-PG | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 4.50% redeemable | PCG-PH | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 4.36% series A redeemable | PCG-PI | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 6% nonredeemable | PCG-PA | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 5.50% nonredeemable | PCG-PB | NYSE American LLC |
| First preferred stock, cumulative, par value \$25 per share, 5% nonredeemable | PCG-PC | NYSE American LLC |

Securities registered pursuant to Section 12(g) of the Act: none

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

PG&E Corporation: ☐ Yes ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

PG&E Corporation: ☐ Yes ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PG&E Corporation: ☒ Yes ☐ No

Pacific Gas and Electric Company: ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation: ☒ Yes ☐ No

Pacific Gas and Electric Company: ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

PG&E Corporation

☒ Large accelerated filer

☐ Non-accelerated filer

☐ Smaller reporting company

☐ Accelerated filer

Pacific Gas and Electric Company

☐ Large accelerated filer

☒ Non-accelerated filer

☐ Smaller reporting company

☐ Accelerated filer

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

PG&E Corporation: ☐

Pacific Gas and Electric Company: ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PG&E Corporation: ☐ Yes ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ No

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.

PG&E Corporation: ☐ Yes ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ No

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2019, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock \$12,130 million

Pacific Gas and Electric Company common stock Wholly owned by PG&E Corporation

Common Stock outstanding as of February 13, 2020:

PG&E Corporation: 529,254,082 shares

Pacific Gas and Electric Company: 264,374,809 shares (wholly owned by PG&E Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

Designated portions of the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders

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UNITS OF MEASUREMENT

| | | |
|-----------------------|---|--|
| 1 Kilowatt (kW) | = | One thousand watts |
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt (GW) | = | One million kilowatts |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |
| 1 Bcf | = | One billion cubic feet |
| 1 MDth | = | One thousand decatherms |

GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

| | |
|-------------------------------|--|
| 2019 Form 10-K | PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2019 |
| 2019 Wildfire Mitigation Plan | the wildfire mitigation plan for 2019 submitted by the Utility to the CPUC pursuant to SB 901, previously also referred to as the "2019 Wildfire Safety Plan" |
| AB | Assembly Bill |
| ALJ | administrative law judge |
| ARAM | average rate assumption method |
| ARO | asset retirement obligation |
| ASU | accounting standard update issued by the FASB (see below) |
| Backstop Party | a third-party investor party to a Backstop Commitment Letter |
| Bankruptcy Code | the United States Bankruptcy Code |
| Bankruptcy Court | the U.S. Bankruptcy Court for the Northern District of California |
| BPP | bundled procurement plan |
| CAISO | California Independent System Operator |
| Cal Fire | California Department of Forestry and Fire Protection |
| CARB | California Air Resources Board |
| CCA | Community Choice Aggregator |
| CCPA | California Consumer Privacy Act of 2018 |
| CEC | California Energy Resources Conservation and Development Commission |
| CEMA | Catastrophic Event Memorandum Account |
| Chapter 11 | chapter 11 of title 11 of the U.S. Code |
| Chapter 11 Cases | the voluntary cases commenced by each of PG&E Corporation and the Utility under Chapter 11 on January 29, 2019 |
| CHT | Customer Harm Threshold |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| CUE | Coalition of California Utility Employees |
| CWSP | Community Wildfire Safety Program |
| DA | Direct Access |
| DER | distributed energy resources |
| Diablo Canyon | Diablo Canyon nuclear power plant |
| DIP Credit Agreement | Senior Secured Superpriority Debtor in Possession Credit, Guaranty and Security Agreement, dated as of February 1, 2019, among the Utility, as borrower, PG&E Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent, and Citibank, N.A., as collateral agent |
| DOE | U.S. Department of Energy |
| DRP | Distribution Resource Plan |
| DTSC | Department of Toxic Substances Control |
| EIM | Energy Imbalance Market |
| Effective Date | the effective date of the Proposed Plan |
| EPA | U.S. Environmental Protection Agency |
| EPS | earnings per common share |
| EV | electric vehicle |
| EVM | enhanced vegetation management |
| FASB | Financial Accounting Standards Board |
| FEMA | Federal Emergency Management Agency |
| FERC | Federal Energy Regulatory Commission |
| FHPMA | Fire Hazard Prevention Memorandum Account |

| | |
|-------------------|---|
| Fire Victim Trust | A trust to be established pursuant to the Proposed Plan for the benefit of holders of the fire victim claims, as defined in Note 14 of the Notes to the Consolidated Financial Statements in Item 8 |
| FRMMA | Fire Risk Mitigation Memorandum Account |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| HSM | hazardous substance memorandum account |
| IOUs | investor-owned utility(ies) |
| LCC | Land Conservation Commitment |
| LIBOR | London Interbank Offered Rate |
| LSTC | liabilities subject to compromise |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K |
| MGP(s) | manufactured gas plants |
| the Monitor | third-party monitor retained as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction |
| NAV | net asset value |
| NDCTP | Nuclear Decommissioning Cost Triennial Proceedings |
| NDT | Diablo Canyon Nuclear Decommissioning Trust |
| NEIL | Nuclear Electric Insurance Limited |
| NEM | net energy metering |
| Noteholder RSA | Restructuring Support Agreement dated as of January 22, 2020 with certain holders of indebtedness of the Utility, among others |
| NRC | Nuclear Regulatory Commission |
| OES | State of California Office of Emergency Services |
| OII | order instituting investigation |
| OIR | order instituting rulemaking |
| OSA | Office of the Safety Advocate, a division of the CPUC |
| PAO | Public Advocates Office of the California Public Utilities Commission (formerly known as Office of Ratepayer Advocates or ORA) |
| PCIA | Power Charge Indifference Adjustment |
| PD | proposed decision |
| Petition Date | January 29, 2019 |
| PFM | petition for modification |
| Proposed Plan | Plan of Reorganization, as defined in Note 2 of the Notes to the Consolidated Financial Statements in Item 8 |
| PSA | plan support agreement |
| PSPS | Public Safety Power Shutoff |
| RAMP | Risk Assessment Mitigation Phase |
| ROE | return on equity |
| ROU asset | right-of-use asset |
| RPS | renewable portfolio standard |
| RSA | restructuring support agreement |
| SB | Senate Bill |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC |
| Subrogation RSA | Restructuring Support Agreement dated September 22, 2019 with certain holders of insurance subrogation claims, as amended |

| | |
|--------------------------|---|
| Tax Act | Tax Cuts and Jobs Act of 2017 |
| TCC | Official Committee of Tort Claimants |
| TCC RSA | Restructuring Support Agreement dated December 6, 2019 with the TCC and attorneys and other advisors and agents for certain holders of Fire Victim Claims (as defined therein), as amended |
| TE | transportation electrification |
| TO | transmission owner |
| TURN | The Utility Reform Network |
| UCC | Official Committee of Unsecured Creditors |
| USAO | United States Attorney's Office for the Northern District of California |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |
| VM | vegetation management |
| WEMA | Wildfire Expense Memorandum Account |
| Wildfire Assistance Fund | program designed to assist those displaced by the 2018 Camp fire and 2017 Northern California wildfires with the costs of temporary housing and other urgent needs |
| Wildfire Fund | statewide fund established by AB 1054 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 |
| Wildfires OII | Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire |
| WMP | wildfire mitigation plan |
| WMPMA | Wildfire Mitigation Plan Memorandum Account |

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to liabilities subject to compromise, insurance receivable, regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the risks and uncertainties associated with the Chapter 11 Cases, including, but not limited to, the ability to develop, consummate, and implement a plan of reorganization with respect to PG&E Corporation and the Utility that satisfies all applicable legal requirements; the ability to obtain applicable Bankruptcy Court, creditor or state or federal regulatory approvals; the effect of any alternative proposals, views or objections related to the plan of reorganization; potential complexities that may arise in connection with concurrent proceedings involving the Bankruptcy Court, the CPUC, and the FERC; increased costs related to the Chapter 11 Cases; the ability to obtain sufficient financing sources for ongoing and future operations and investment; the ability to satisfy the conditions precedent to financing under the Backstop Commitment Letters and the Debt Commitment Letters and the risk that such agreements may be terminated; the risk that the Noteholder RSA, the Subrogation RSA, the TCC RSA or the PSAs could be terminated; disruptions to PG&E Corporation's and the Utility's business and operations and the potential impact on regulatory compliance;
- whether, PG&E Corporation and the Utility will be able to emerge from Chapter 11 by June 30, 2020 with a plan of reorganization that is deemed to meet the requirements of AB 1054, and whether PG&E Corporation and the Utility will need to undertake significant changes in ownership, management and governance in connection therewith;

- if the Proposed Plan is determined not to meet the requirements of AB 1054 or the Utility does not otherwise participate in the Wildfire Fund under AB 1054, it could result in a significant delay in emergence from bankruptcy, as PG&E Corporation and the Utility may be required to make material modifications or amendments to their Proposed Plan, to develop and consummate a new consensual plan of reorganization or engage in a contested proceeding;
- restrictions on PG&E Corporation's and the Utility's ability to pursue strategic and operational initiatives for the duration of the Chapter 11 Cases;
- PG&E Corporation's and the Utility's historical financial information not being indicative of future financial performance as a result of the Chapter 11 Cases and the potential financial and other restructuring currently contemplated by the Proposed Plan;
- the possibility that PG&E Corporation and the Utility will not be able to meet the conditions precedent to funding under the Backstop Commitment Letters and the Debt Commitment Letters, or that events or circumstances will occur that give rise to termination rights of the Backstop Parties or Commitment Parties under the Backstop Commitment Letters or Debt Commitment Letters, respectively, which could make raising funds to pay claims and exit Chapter 11 difficult or uneconomic;
- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner and on acceptable terms in order to exit Chapter 11 and to raise financing for operations and investment after emergence;
- the impact of AB 1054 on potential losses in connection with future wildfires, including the CPUC's implementation of the procedures for recovering such losses;
- whether, in light of the CPUC's July 8, 2019 final decision in the CHT OIR that excludes companies in Chapter 11 from accessing the CHT, the Utility will be able to obtain substantial recovery of costs related to the 2017 Northern California wildfires;
- the impact of the 2018 Camp fire and the 2017 Northern California wildfires, including whether the Utility will be able to timely recover costs incurred in connection with the wildfires through rates; the timing and outcome of the remaining wildfire investigations and the extent to which the Utility will have liability associated with these fires; the timing and amount of insurance recoveries; and potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency were to bring an enforcement action, including a criminal proceeding, and determined that the Utility failed to comply with applicable laws and regulations (which actions could also adversely impact a timely emergence from Chapter 11);
- the ability of PG&E Corporation and the Utility to finance costs, expenses and other possible losses with respect to claims related to the 2018 Camp fire and the 2017 Northern California wildfires, through securitization mechanisms or otherwise, which potential financings are not addressed by AB 1054 as it only applies to wildfires occurring after July 12, 2019;
- the timing and outcome of any proceeding to recover 2015 Butte fire-related costs in excess of insurance through rates;
- the risks and uncertainties associated with the 2019 Kincadee fire;
- the timing and outcome of future regulatory and legislative developments in connection with SB 901, including future wildfire reforms, inverse condemnation reform, and other wildfire mitigation measures or other reforms targeted at the Utility or its industry;
- the outcome of the Utility's CWSP that the Utility has developed in coordination with first responders, civic and community leaders, and customers, to help reduce wildfire threats and improve safety as a result of climate-driven wildfires and extreme weather, including the Utility's ability to comply with the targets and metrics set forth in the 2020-2022 Wildfire Mitigation Plan; and the cost of the program and the timing and outcome of any proceeding to recover such cost through rates;
- whether the Utility will be able to obtain full recovery of its significantly increased insurance premiums, and the timing of any such recovery;

- whether the Utility can obtain wildfire insurance at a reasonable cost in the future, or at all, and whether insurance coverage is adequate for future losses or claims;
- increased employee attrition as a result of the filing of the Chapter 11 Cases and the challenging political and operating environment facing the company;
- the impact of the Utility's implementation of its PSPS program, including the timing and outcome of the PSPS OII and order to show cause, and whether any fines or penalties or civil liability for damages will be imposed on the Utility as a result; the costs in connection with PSPS events, and the effects on PG&E Corporation's and the Utility's reputations caused by implementation of the PSPS program;
- the timing and outcomes of the 2020 GRC, FERC TO18, TO19, and TO20 rate cases, 2018 and 2019 CEMA applications, WEMA application, future applications for FHPMA, FRMMA, and WMPMA, future cost of capital proceedings, and other ratemaking and regulatory proceedings;
- the outcome of the probation and the monitorship imposed by the federal court after the Utility's conviction in the federal criminal trial in 2017, the timing and outcomes of the debarment proceeding, potential reliability penalties or sanctions from the North American Electric Reliability Corporation, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility's compliance with natural gas- and electric- related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes including the costs of complying with any additional conditions of probation imposed in connection with the Utility's federal criminal proceeding, such as expenses associated with any material expansion of the Utility's vegetation management program following the entry on January 16, 2020 of an order to show cause by the United States District Court for the Northern District of California, as well as the impact of additional conditions of probation on PG&E Corporation's and the Utility's ability to make distributions to shareholders;
- the effects on PG&E Corporation's and the Utility's reputations caused by matters such as the CPUC's investigations and enforcement proceedings;
- the outcome of the Safety Culture OII proceeding, and future legislative or regulatory actions that may be taken, such as requiring the Utility to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or transfer ownership of the Utility's assets to municipalities or other public entities, or implement corporate governance changes;
- whether the Utility can control its operating costs within the authorized levels of spending, and timely recover its costs through rates; whether the Utility can continue implementing a streamlined organizational structure and achieve project savings, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs; and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;
- whether the Utility and its third-party vendors and contractors are able to protect the Utility's operational networks and information technology systems from cyber- and physical attacks, or other internal or external hazards;
- the timing and outcome in the Court of Appeals of the appeal of FERC's order denying rehearing on September 19, 2019 of the complaint filed by the CPUC and certain other parties that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the CAISO's Transmission Planning Process to allow for greater participation and input from interested parties; and the timing and outcome of FERC's Order on Remand on July 18, 2019 granting the Utility a 50 basis point ROE incentive adder for continued participation in the CAISO;
- the outcome of current and future self-reports, investigations, or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion, or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cybersecurity, environmental laws and regulations; and the outcome of existing and future SED notices of violations;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;
- the impact of SB 100, which was signed into law on September 10, 2018, that increases the percentage from 50% to 60% of California's electricity portfolio that must come from renewables by 2030; and establishes state policy that 100% of all retail electricity sales must come from renewable portfolio standard-eligible or carbon-free resources by 2045;
- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, EVs, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;
- the impact of the California governor's executive order issued on January 26, 2018, to implement a new target of five million zero-emission vehicles on the road in California by 2030;
- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California and the Utility's fossil fuel-fired generation sites;
- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of potential actions, such as legislation, taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon until its planned retirement;
- the impact of wildfires, droughts, floods, or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and the reparation and other costs that the Utility may incur in connection with such conditions or events; the impact of the adequacy of the Utility's emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and sufficient to cover the Utility's liability;
- whether the Utility's climate change adaptation strategies are successful;
- the breakdown or failure of equipment that can cause damages, including fires, and unplanned outages; and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;
- the impact that reductions in Utility customer demand for electricity and natural gas, driven by customer departures to CCAs and DA providers, have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, and changing customer demand for its natural gas and electric services;
- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;
- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- the impact of the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the uncertainty in connection with the 2018 Camp fire and the 2017 Northern California wildfires, the ultimate outcomes of the CPUC's pending investigations, and other enforcement matters will impact the Utility's ability to make distributions to PG&E Corporation;
- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;
- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the current federal administration; and
- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors below and a detailed discussion of these matters contained in Item 7. MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

PART I

ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found below in Item 6. Selected Financial Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. Each of PG&E Corporation and the Utility is a separate entity, with distinct creditors and claimants, and is subject to separate laws, rules, and regulations.

At December 31, 2019, PG&E Corporation and the Utility had approximately 23,000 regular employees, approximately 12 of which were employees of PG&E Corporation. Of the Utility's regular employees, approximately 15,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers (IBEW) Local 1245; the Engineers and Scientists of California (ESC) IFPTE 20; and the Service Employees International Union. The collective bargaining agreements currently in effect will expire on December 31, 2021. As part of the bankruptcy plan of reorganization, the IBEW Local 1245, and the Utility reached a tentative agreement to extend the current collective bargaining agreement that is set to expire on December 31, 2021 through December 31, 2025. The tentative agreement increases wages annually by 3.75% from 2022 through 2025 and maintains current contributions to specified benefits. The IBEW represents approximately 50% of the Utility's employee workforce, and supports several areas of the Utility's business, including gas and electric operations. The Utility plans to work with its other unions, the Engineers and Scientists of California, Local 20, and Service Employees International Union, Local 24/7 to negotiate potential contract extensions.

PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, www.pgecorp.com, and the Utility's website, www.pge.com, as promptly as practicable after they are filed with, or furnished to, the SEC. Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings before the CPUC and the FERC at <http://investor.pgecorp.com>, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at <http://investor.pgecorp.com>, under the "Chapter 11," "Wildfire Updates" and "News & Events: Events & Presentations" tabs, respectively, in order to publicly disseminate such information. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on such websites are not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to such websites solely for the information of investors and do not intend the addresses to be an active link.

In 2019, 2018 and 2017, Northern California experienced major wildfires. For more information about the 2019 Kincadee fire, the 2018 Camp fire and the 2017 Northern California wildfires, see Item 3. Legal Proceedings, Item 7. MD&A, and Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

This 2019 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors and the section entitled "Forward-Looking Statements" above.

Chapter 11 Proceedings

On January 29, 2019, PG&E Corporation and the Utility filed for Chapter 11 protection. For more information about the Chapter 11 bankruptcy filings see Item 7. MD&A and Note 2 of the Notes to the Consolidated Financial Statements in Item 8.

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. Management has concluded that these circumstances raise substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns, and their independent registered public accountants have included an explanatory paragraph in their auditors' report which states certain conditions exist which raise substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns in relation to the foregoing. For more information about these matters, see Item 7. MD&A and Note 1 of the Notes to the Consolidated Financial Statements in Item 8.

Regulatory Environment

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is subject to the jurisdiction of the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies, including with respect to safety, the environment, and health. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility.

PG&E Corporation is a "public utility holding company" as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

The California Public Utilities Commission

The CPUC is a regulatory agency that regulates privately owned public utilities in California. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electric and natural gas distribution operations, electric generation, and natural gas transmission and storage services. The CPUC also has exercised jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electric and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to \$100,000 per day, per violation. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under the current gas and electric citation programs adopted by the CPUC in September 2016, the SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it has the authority to impose the maximum statutory penalty of \$100,000, with an administrative limit of \$8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED has the discretion to either address each violation in a distinct citation or to include multiple violations in a single citation regardless of whether the violations occurred in the same incident or are of a similar nature. Penalty payments for citations issued pursuant to the gas and electric safety citation programs are the responsibility of shareholders of an issuer and must not be recovered in rates or otherwise directly or indirectly charged to customers.

The California State Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to wildfires and wildfire cost recovery, increasing renewable energy resources, the development and widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, the establishment of energy storage procurement targets, and the development of a state-wide electric vehicle charging infrastructure. The CPUC is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs. The CPUC also conducts audits and reviews of the Utility's accounting, performance, and compliance with regulatory guidelines.

The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation's Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see "Liquidity and Financial Resources" in Item 7. MD&A and Item 1A. Risk Factors.)

The Federal Energy Regulatory Commission and the California Independent System Operator

The FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility's transmission systems with other electric system and generation facilities, the tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation's electric transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. FERC approval is also required under Federal Power Act Section 203 before undertaking certain transactions, including most mergers and consolidations, certain transactions that result in a change in control of a utility, purchases of utility securities and dispositions of utility property. The FERC has authority to impose fines of up to \$1 million per day for violations of certain federal statutes and regulations.

The CAISO is the FERC-approved regional transmission organization for the Utility's service territory. The CAISO controls the operation of the electric transmission system in California and provides open access transmission service on a non-discriminatory basis. The CAISO is also responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generating capacity, ensuring that the reliability of the transmission system is maintained, and operating an interstate EIM.

The Nuclear Regulatory Commission

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electricity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. (For more information about Diablo Canyon, see Item 3. Legal Proceedings below.)

Third-party Monitor

On April 12, 2017, the Utility retained a third-party monitor at the Utility's expense as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction, which sentenced the Utility to, among other things, a five-year corporate probation period and oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years. The goal of the third-party monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations and maintains effective ethics, compliance, and safety related incentive programs on a Utility-wide basis. (For more information see Item 1A. Risk Factors and in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

Other Regulators

The CEC is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans and for adopting building and appliance energy efficiency requirements.

The CARB is the state agency responsible for setting and monitoring GHG and other emission limits. The CARB is also responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California. (See "Environmental Regulation - Air Quality and Climate Change" below.)

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and highways. In exchange for the right to use public streets and highways, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. (For more information see Item 1A. Risk Factors.)

Ratemaking Mechanisms

The Utility's rates for electric and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service and a return on invested capital ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administration and general expenses) and capital costs (e.g., depreciation, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Item 7. MD&A), including its costs to procure electricity, natural gas and nuclear fuel, to administer public purpose and customer programs, and to decommission its nuclear facilities.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. Similarly, the authorized rate of return on all other Utility assets is set in the CPUC's cost of capital proceeding. Other than certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume through certain regulatory balancing accounts, or revenue adjustment mechanisms, that are designed to allow the Utility to fully collect its authorized base revenue requirements. As a result, the Utility's base revenues are not impacted by fluctuations in sales resulting from, for example, weather or economic conditions. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

Due to the seasonal nature of the Utility's business and rate design, customer electric bills are generally higher during summer months (May - October) because of higher demand, driven by air conditioning loads. Customer bills related to gas service generally increase during the winter months (November - March) to account for the gas peak due to heating.

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn some additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs.

See "Regulatory Matters" in Item 7. MD&A for more information on specific CPUC proceedings.

Base Revenues

General Rate Cases

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs, including return on rate base, related to its electric distribution, natural gas distribution, and Utility-owned electric generation operations. The CPUC generally conducts a GRC every three or four years. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). Attrition year rate adjustments are generally provided for cost increases related to increases in invested capital and inflation. Parties in the Utility's GRC include the PAO and TURN, which generally represent the overall interests of residential customers, as well as numerous intervenors that represent other business, community, customer, environmental, and union interests.

On January 16, 2020, the CPUC approved a final decision in its OIR to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the GRC Plan, as a result of which the Utility will combine its GRC and GT&S rate cases starting with the 2023 GRC and 2023 GT&S rate case. (For more information about the Utility's GRC, see "Regulatory Matters 2017 General Rate Case" and "Regulatory Matters 2020 General Rate Case" in Item 7. MD&A.)

Natural Gas Transmission and Storage Rate Cases

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in the GT&S rate case. The CPUC generally conducts a GT&S rate case every three or four years. Similar to the GRC, the CPUC approves the annual revenue requirements for the first year (or "test year") of the GT&S rate case period and typically determines annual increases in revenue requirements for attrition years of the GT&S rate case period. Parties in the Utility's GT&S rate case include the PAO and TURN, who generally represent the overall interests of residential customers, as well as other intervenors who represent other business, community, customer, environmental, and union interests.

As previously mentioned, on January 16, 2020, the CPUC approved a final decision that requires the Utility to combine its GRC and GT&S rate cases starting with the 2023 GRC and 2023 GT&S rate case. (For more information, see "Regulatory Matters - 2015 Gas Transmission and Storage Rate Case" and "Regulatory Matters - 2019 Gas Transmission and Storage Rate Case" in Item 7. MD&A.)

Cost of Capital Proceedings

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. On December 19, 2019, the CPUC issued a final decision that authorizes the Utility's capital structure through 2023, consisting of 52% common equity, 47.5% long-term debt, and 0.5% preferred stock. The CPUC also set the authorized ROE through 2023 at 10.25% and reset the cost of debt to 5.16%. The CPUC also authorized the continuation of an adjustment mechanism to allow the Utility's cost of debt and ROE to be adjusted if the utility bond index changes by certain thresholds, which are reviewed annually. The CPUC has indicated it will determine in the OII to Consider PG&E Corporation's and the Utility's Proposed Plan of Reorganization if the Utility needs to submit a cost of capital application after it emerges from Chapter 11.

Electricity Transmission Owner Rate Cases

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 Utility has historically filed a TO rate case every year. 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. In 2018, the Utility filed a formula rate at FERC, which would be updated annually according to the formula. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and by the CAISO in its Transmission Access Charges to wholesale customers. (For more information, see "Regulatory Matters - Transmission Owner Rate Cases" in Item 7. MD&A.) The Utility also recovers a portion of its revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are charged individualized rates based on the terms of their contracts.

Memorandum Account Costs

Periodically, costs arise which could not be anticipated by the Utility during CPUC GRC rate requests or which are deliberately excluded therefrom. These costs may result from catastrophic events, changes in regulation, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. These accounts allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. While the Utility believes such costs are recoverable, rate recovery requires CPUC authorization in separate proceedings or through a GRC. (For more information, see "Regulatory Matters - Wildfire Expense Memorandum Account," "Regulatory Matters - Catastrophic Expense Memorandum Account," and "Regulatory Matters - Fire Hazard Prevention Memorandum Account" in Item 7. MD&A.)

Revenues to Recover Energy Procurement and Other Pass-Through Costs

Electricity Procurement Costs

California investor-owned electric utilities are responsible for procuring electrical capacity required to meet bundled customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electric contracts. The utilities are responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their BPPs based on long-term demand forecasts. In October 2015, the CPUC approved the Utility's most recent comprehensive BPP. It was revised since its initial approval and will remain in effect as revised until superseded by a subsequent CPUC-approved plan. On February 8, 2019, the CPUC approved the Utility's filing that permitted the Utility to temporarily manage certain elements of its current BPP as a result of its financial condition, effective as of January 16, 2019. Additionally, on January 25, 2019, the Utility filed with the CPUC an update to its BPP to further refine how it manages certain elements of its procurement activity and provide detail of its sales framework. The updated BPP was effective upon CPUC approval on May 30, 2019.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved BPPs without further after-the-fact reasonableness review by the CPUC. The CPUC may disallow costs associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to follow the principles of least-cost dispatch. Additionally, the CPUC may disallow the cost of replacement power procured due to unplanned outages at utility-owned generation facilities.

The Utility recovers its electric procurement costs annually primarily through balancing accounts. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.) Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electric rates more frequently if the forecasted aggregate over-collections or under-collections in the energy resource recovery account exceed 5% of its prior year electric procurement and Utility-owned generation revenues. The CPUC performs an annual compliance review of the transactions recorded in the energy resource recovery account.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, to meet mandatory renewable energy targets, and to comply with resource adequacy requirements. (For more information, see "Electric Utility Operations - Electricity Resources" below as well as Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

Natural Gas Procurement, Storage, and Transportation Costs

The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electric rates.

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as "core" customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments for its core gas portfolio, through its retail gas rates, subject to limits as set forth in its core procurement incentive mechanism described below. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rate changes.

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs for its core gas portfolio. Under the core procurement incentive mechanism, the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of these savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by FERC-approved tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. The FERC approves the United States tariffs that shippers, including the Utility, pay for pipeline service, and the applicable Canadian tariffs are approved by the National Energy Board, a Canadian regulatory agency. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as a cost of electricity.

Costs Associated with Public Purpose and Customer Programs

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide discounted rates for specified types of customers, such as for low-income customers under the California Alternate Rates for Energy (“CARE”) program, which is paid for by the Utility’s other customers.

Nuclear Decommissioning Costs

The Utility’s nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities 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. Nuclear decommissioning costs are generally collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approval of the Utility’s updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility’s nuclear plants.

For costs related to Asset Retirement Obligations see “Nuclear Decommissioning Obligation” in Note 3 of the Notes to the Consolidated Financial Statements in item 8.

Electric Utility Operations

The Utility generates electricity and provides electric transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides “bundled” services (i.e., electricity, transmission and distribution services) to customers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations. (For more information, see “Regulatory Matters” in Item 7. MD&A.)

Electricity Resources

The Utility is required to maintain capacity adequate to meet its customers’ demand for electricity (“load”), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule all of the electric resources within its portfolio using least-cost dispatch.

The following table shows the percentage of the Utility’s total deliveries of electricity to customers in 2019 represented by each major electric resource, and further discussed below.

Total 2019 actual electricity generated and procured (net) - 35,956 GWh ⁽¹⁾:

| | Percent of Bundled Retail Sales (actual procurement) | Percent of Bundled Retail Sales (Power Content Label) ⁽²⁾ |
|--|--|--|
| Owned Generation Facilities | | |
| Nuclear | 45.0 % | 41.7 % |
| Small Hydroelectric | 2.4 % | 2.2 % |
| Large Hydroelectric | 28.3 % | 26.3 % |
| Fossil fuel-fired | 17.6 % | — % |
| Solar | 0.8 % | 0.7 % |
| Total | 94.1 % | 70.9 % |
| Qualifying Facilities | | |
| Renewable | 0.6 % | 0.6 % |
| Non-Renewable | 6.4 % | — % |
| Total | 7.0 % | 0.6 % |
| Irrigation Districts and Water Agencies | | |
| Small Hydroelectric | 0.1 % | 0.1 % |
| Large Hydroelectric | — % | — % |
| Total | 0.1 % | 0.1 % |
| Other Third-Party Purchase Agreements | | |
| Renewable | 25.8 % | 23.8 % |
| Large Hydroelectric | 5.0 % | 4.6 % |
| Non-Renewable | 12.6 % | — % |
| Total | 43.4 % | 28.4 % |
| Others, Net ⁽²⁾⁽³⁾ | (44.6)% | — % |
| Total | 100.0 % | 100.0 % |

⁽¹⁾ This amount excludes electricity provided by direct access providers and CCAs that procure their own supplies of electricity for their respective customers.

⁽²⁾ The allocation of bundled retail sale amounts and “Others, Net” in the “Power Content Label” column is consistent with current CEC guidelines, applied to specified electric generation and procurement volumes (i.e., fossil fuel-fired, nuclear, large hydroelectric, and renewable). Total reported generation and procurement volumes equate to actual electric retail sales.

⁽³⁾ Amount is mainly comprised of net CAISO open market (sales)/purchases.

Renewable Energy Resources

California law established an RPS that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers. In October 2015, the California Governor signed SB 350, the Clean Energy and Pollution Reduction Act of 2015 into law. SB 350 became effective January 1, 2016, and increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period, and in each three-year compliance period thereafter, unless changed by legislative action. SB 350 provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. In September 2018, the California Governor signed SB 100 into law, increasing from 50% to 60% of California’s electricity portfolio that must come from renewables by 2030; and established state policy that 100 percent of all retail electricity sales must come from RPS-eligible or carbon-free resources by 2045. The Utility may incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable from customers as “pass-through” costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher renewable targets.

Renewable generation resources, for purposes of the RPS requirements, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. RPS requirements are based on actual procurement, which aligns with the methodology presented in the first column of the table above. Actual procurement from renewable energy sources was 29.7% in 2019. Per the Power Content Label methodology presented in the table above, 27.4% of the Utility’s energy deliveries were from renewable energy sources.

The total 2019 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales |
|----------------------------|---------------|---------------------------------|
| Biopower | 1,322 | 3.7 % |
| Geothermal | 539 | 1.5 % |
| Wind | 3,412 | 9.5 % |
| RPS-Eligible Hydroelectric | 827 | 2.3 % |
| Solar | 4,574 | 12.7 % |
| Total | 10,674 | 29.7 % |

Energy Storage

As required by California law, the CPUC established a multi-year energy storage procurement framework, including energy storage procurement targets to be achieved by each load-serving entity under the CPUC jurisdiction, including the Utility. Under the adopted energy storage procurement framework, the Utility is required to procure 580 MW of qualifying storage capacity by the end of 2021, with all energy storage projects required to be operational by the end of 2024.

The CPUC also adopted biennial interim storage targets for the Utility, beginning in 2014 and ending in 2020. Under the adopted framework, the Utility is required to submit biennial energy storage procurement plans to describe its strategy to meet its interim and total energy storage targets.

Through its procurements to date, the Utility has largely met its storage targets. The Utility expects to meet its remaining target through existing customer programs. This outcome may change in the future if projects under contract are terminated or if projects fail to be developed.

Owned Generation Facilities

At December 31, 2019, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---------------------------------|--|-----------------|-----------------------------|
| Nuclear ⁽¹⁾ : | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric ⁽²⁾ : | | | |
| Conventional | 16 counties in northern and central California | 102 | 2,679 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| Fuel Cell: | | | |
| CSU East Bay Fuel Cell | Alameda | 1 | 1 |
| SF State Fuel Cell | San Francisco | 2 | 2 |
| Photovoltaic ⁽³⁾ : | Various | 13 | 152 |
| Total | | 135 | 7,686 |

- ⁽¹⁾ The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses expire in 2024 and 2025, respectively. On January 11, 2018, the CPUC approved the Utility's application to retire Unit 1 by 2024 and Unit 2 by 2025. (See "Diablo Canyon Nuclear Power Plant" in Item 7. MD&A and Item 3. Legal Proceedings.)
- ⁽²⁾ The Utility's hydroelectric system consists of 105 generating units at 66 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years.
- ⁽³⁾ The Utility's large photovoltaic facilities are Cantua solar station (20 MW), Five Points solar station (15 MW), Gates solar station (20 MW), Giffen solar station (10 MW), Guernsey solar station (20 MW), Huron solar station (20 MW), Stroud solar station (20 MW), West Gates solar station (10 MW), and Westside solar station (15 MW). All of these facilities are located in Fresno County, except for Guernsey solar station, which is located in Kings County.

Generation Resources from Third Parties

The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. (See "Ratemaking Mechanisms" above.) For more information regarding the Utility's power purchase agreements, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

At December 31, 2019, the Utility owned approximately 18,000 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 33 electric transmission substations with a capacity of approximately 65,000 MVA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes many western states, the Canadian provinces of Alberta and British Columbia, and parts of Mexico.

Decisions about expansions and maintenance of the transmission system can be influenced by decisions of the Utility's regulators and the CAISO.

Electricity Distribution

The Utility's electric distribution network consists of approximately 107,000 circuit miles of distribution lines (of which, as of December 31, 2019, approximately 25% are underground and approximately 75% are overhead), 68 transmission switching substations, and 760 distribution substations, with a capacity of approximately 32,000 MVA. The Utility's distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

These distribution substations serve as the central hubs for the Utility's electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. The Utility operates electric distribution control center facilities in Concord, Rocklin, and Fresno, California; these control centers form a key part of the Utility's efforts to create a smarter, more resilient grid.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2017 to 2019 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 2019, 2018 or 2017.

| | 2019 | 2018 | 2017 |
|--|------------------|------------------|------------------|
| Customers (average for the year) | 5,457,101 | 5,428,318 | 5,384,525 |
| Deliveries (in GWh) ⁽¹⁾ | 78,070 | 79,774 | 82,226 |
| Revenues (in millions): | | | |
| Residential | \$ 4,847 | \$ 5,051 | \$ 5,693 |
| Commercial | 4,756 | 4,908 | 5,431 |
| Industrial | 1,493 | 1,532 | 1,603 |
| Agricultural | 1,106 | 1,234 | 1,069 |
| Public street and highway lighting | 67 | 72 | 79 |
| Other ⁽²⁾ | 168 | (720) | (294) |
| Subtotal | 12,437 | 12,077 | 13,581 |
| Regulatory balancing accounts ⁽³⁾ | 303 | 636 | (344) |
| Total operating revenues | \$ 12,740 | \$ 12,713 | \$ 13,237 |
| Selected Statistics: | | | |
| Average annual residential usage (kWh) | 5,750 | 5,772 | 6,231 |
| Average billed revenues per kWh: | | | |
| Residential | \$ 0.1762 | \$ 0.1838 | \$ 0.1936 |
| Commercial | 0.1585 | 0.1627 | 0.1716 |
| Industrial | 0.1015 | 0.1010 | 0.1055 |
| Agricultural | 0.2172 | 0.1968 | 0.2041 |
| Net plant investment per customer | \$ 8,375 | \$ 7,950 | \$ 7,486 |

⁽¹⁾ These amounts include electricity provided by direct access providers and CCAs that procure their own supplies of electricity for their respective customers.

⁽²⁾ This activity is primarily related to provisions for rate refunds and unbilled electric revenue, partially offset by other miscellaneous revenue items.

⁽³⁾ These amounts represent revenues authorized to be billed.

Natural Gas Utility Operations

The Utility provides natural gas transportation services to “core” customers (i.e., small commercial and residential customers) and to “non-core” customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e., natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as “core transport agents”). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as “bundled” natural gas service. Currently, more than 97% of core customers, representing approximately 82% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility generally does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers, unless the customer is a natural gas-fired generation facility with which the Utility has a power purchase agreement that includes its generation fuel expense. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers (i.e., outside of the Utility's service territory) and to third-party natural gas storage customers.

Natural Gas Supplies

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility can also receive natural gas from fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have varied generally based on market conditions. During 2019, the Utility purchased approximately 282,000 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all of this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 20% of the total natural gas volume the Utility purchased during 2019.

Natural Gas System Assets

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 2019, the Utility's natural gas system consisted of approximately 43,300 miles of distribution pipelines, over 6,300 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. interconnecting downstream with TransCanada Foothills Pipe Lines Ltd., B.C. System. The Foothills system interconnects at the border to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport natural gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border. Similarly, the Utility has a firm transportation agreement with Transwestern Pipeline Company, LLC to transport natural gas from supply points in the Southwestern United States to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. (For more information regarding the Utility's natural gas transportation agreements, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's transmission system. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later withdrawal. In addition, four independent storage operators are interconnected to the Utility's northern California transmission system. In 2019, the CPUC approved the discontinuation (through closure or sale) of operations at two gas storage fields. (For more information, see "Regulatory Matters - 2019 Gas Transmission and Storage Rate Case" in Item 7. MD&A.)

In 2019, the Utility continued upgrading transmission pipeline to allow for the use of in-line inspection tools and continued its work on the final NTSB recommendation from its San Bruno investigation to hydrostatically test all high consequence pipeline mileage. The Utility currently plans to complete this NTSB recommendation by 2022 for remaining short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2017 through 2019 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 2019, 2018 or 2017.

| | 2019 | 2018 | 2017 |
|--|-----------------|-----------------|-----------------|
| Customers (average for the year) ⁽¹⁾ | 4,518,209 | 4,495,279 | 4,467,657 |
| Gas purchased (MMcf) | 227,621 | 219,061 | 234,181 |
| Average price of natural gas purchased | \$ 2.08 | \$ 2.02 | \$ 2.3 |
| Bundled gas sales (MMcf): | | | |
| Residential | 162,876 | 156,917 | 160,969 |
| Commercial | 54,479 | 51,357 | 50,329 |
| Total Bundled Gas Sales | 217,355 | 208,274 | 211,298 |
| Revenues (in millions): | | | |
| Bundled gas sales: | | | |
| Residential | \$ 2,325 | \$ 2,042 | \$ 2,298 |
| Commercial | 605 | 537 | 541 |
| Other | 123 | 75 | (25) |
| Bundled gas revenues | 3,053 | 2,654 | 2,814 |
| Transportation service only revenue | 1,249 | 1,151 | 976 |
| Subtotal | 4,302 | 3,805 | 3,790 |
| Regulatory balancing accounts ⁽²⁾ | 87 | 242 | 221 |
| Total operating revenues | \$ 4,389 | \$ 4,047 | \$ 4,011 |
| Selected Statistics: | | | |
| Average annual residential usage (Mcf) | 38 | 38 | 38 |
| Average billed bundled gas sales revenues per Mcf: | | | |
| Residential | \$ 13.88 | \$ 12.67 | \$ 14.27 |
| Commercial | 9.72 | 9.04 | 11.36 |
| Net plant investment per customer | \$ 3,522 | \$ 3,417 | \$ 3,093 |

⁽¹⁾ These amounts include natural gas provided by core transport agents and CCAs that procure their own supplies of natural gas for their respective customers.

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

Competition

Competition in the Electricity Industry

California law allows qualifying non-residential electric customers of investor-owned electric utilities to purchase electricity from energy service providers rather than from the utilities up to certain annual and overall GWh limits that have been specified for each utility. This arrangement is known as “direct access,” or DA. In 2018, the California legislature passed a bill to expand the statewide DA cap by 4,000 GWh, and directed the CPUC to consider whether DA should be further expanded, and to present a report on this matter to the legislature by June 30, 2020. In addition, California law permits cities, counties, and certain other public agencies that have qualified to become a CCA to generate and/or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents and businesses that do not affirmatively elect to continue to receive electricity generated or procured by a utility. On June 3, 2019, the CPUC issued an order implementing the 4,000 GWh increase for DA transactions, including an apportionment to the Utility’s service area of approximately 1,873 GWh. The CPUC is currently conducting a study to inform its recommendations to the legislature on implementing a further direct transaction reopening schedule and plans to issue a proposed decision on these issues on May 22, 2020.

The Utility continues to provide transmission, distribution, metering, and billing services to direct access customers, although these customers can choose to obtain metering and billing services from their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Utility is able to collect charges intended to recover the generation-related costs that the Utility incurred on behalf of direct access and CCA customers while they were the Utility’s customers. The Utility remains the electricity provider of last resort for these customers. SB 520 (codified at Section 387 of the Public Utilities Code), which was signed by the governor and became law on October 2, 2019, allows for a request to transfer the responsibilities of the provider of last resort obligation from investor-owned utilities to other entities.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering (“NEM”), which allows self-generating customers employing qualifying renewable resources to receive bill credits at the full retail rate, are increasing, putting upward rate pressure on remaining customers. New NEM customers are required to pay an interconnection fee, utilize time of use rates, and are required to pay certain non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. Significantly higher bills for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers or adopt self-generation technologies. The CPUC has indicated that it intends to commence a new proceeding to revisit its rules related to NEM customers in 2020.

Further, in some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, may seek to acquire the Utility’s distribution facilities, through eminent domain (although eminent domain is stayed while the Utility is in Chapter 11, unless the Bankruptcy Judge lifts the stay). In 2019, three entities communicated an interest in acquiring certain Utility assets through a voluntary sale during the bankruptcy. It is also possible that some of the governmental entities interested in acquiring the Utility’s assets will construct duplicate distribution facilities to serve existing or potential new Utility customers.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission facilities within, or interconnected to, its service territory through a competitive bidding process managed by the CAISO.

The effect of such types of retail competition generally is to reduce the number of utility customers, leading to a reduction in the amount of electricity purchased from the Utility.

(For risks in connection with increasing competition, see Item 1A. Risk Factors.)

Competition in the Natural Gas Industry

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

Environmental Regulation

The Utility's operations are subject to extensive federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of CO₂ and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. (See Item 1A. Risk Factors.) Generally, the Utility recovers most of the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a ratemaking mechanism described in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to various regulations adopted by the U.S. Environmental Protection Agency (EPA), including the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended. The Utility is also subject to the regulations adopted by other federal agencies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act, these persons (known as "potentially responsible parties") may be jointly and severally liable for the costs of cleaning up the hazardous substances, monitoring and paying for the harm caused to natural resources, and paying for the costs of health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the California DTSC, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Air Quality and Climate Change

The Utility's electric generation plants, natural gas pipeline operations, vehicle fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, CO₂, sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulate matter, and other emissions.

Federal Regulation

At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

The federal administration of President Donald Trump has generated significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. In the absence of policy at the federal level, the State of California has indicated that it intends to continue and enhance its leadership on climate change nationally and globally.

California's AB 32, the Global Warming Solutions Act of 2006, provides for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target, including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy.

The cap-and-trade program's first compliance period, which began on January 1, 2013, applied to the electric generation and large industrial sectors. In the subsequent compliance period, which began on January 1, 2015, the scope of the regulation was expanded to include the natural gas and transportation sectors, effectively covering all of the state economy's major sectors through 2020. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than large natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. In 2017, AB 398 extended the program through January 1, 2031. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Entities with a compliance obligation can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Complying entities may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owners, and farmers) that occur outside of the entities' facilities through CARB-qualified offset projects such as reforestation or biomass projects.

SB 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. In 2017, AB 398 extended the cap-and-trade program through 2030. The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers. The California RPS program that requires the utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California. In September 2018, SB 100 was signed into law, which accelerated the state's 50% RPS target to December 31, 2026, increased the RPS target to 60% by December 31, 2030, and further amended the RPS statute to set a policy of meeting 100% of retail sales from eligible renewables and zero-carbon resources by December 31, 2045.

Climate Change Resilience Strategies

During 2019, the Utility continued its programs to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to plan for the actions that it will need to take to increase its resilience in light of the impacts of climate change on the Utility's operations. The Utility regularly reviews the most relevant scientific literature on climate change such as rising sea levels, major storm events, increasing temperatures and heatwaves, wildfires, drought and land subsidence, to help the Utility identify and evaluate climate change-related risks and develop the necessary resilience strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including wildfires, extreme storms, and heat waves and uses its risk-assessment process to prioritize infrastructure investments for longer-term risks associated with climate change. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

The Utility is working to better understand the current and future impacts of climate change. In 2017, the Utility filed its first RAMP submittal with the CPUC, which examined Utility safety risks. The Climate Resilience RAMP model indicated potential additional Utility safety consequences due to climate change, including in the near term. The Utility is conducting foundational work to help anticipate and plan for evolving conditions in terms of weather and climate-change related events. This work is guiding efforts to design a Utility-wide climate change risk integration strategy. This strategy will inform resource planning and investment, operational decisions, and potential additional programs to identify and pursue mitigations that will incorporate the resilience and safety of the Utility's assets, infrastructure, operations, employees, and customers.

With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more extreme, persistent, and frequent hot weather. The Utility believes its strategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage are effective strategies for adapting to the expected changes in demand for electricity. The Utility is making substantial investments to build a more modern and resilient system that can better withstand extreme weather and related emergencies. Over the long term, the Utility also faces the risk of higher flooding and inundation potential at coastal and low elevation facilities due to projected sea level rise combined with high tides, storm runoff and storm surges. As the state continues to face increased risk of wildfires, the Utility's activities, including vegetation management, will continue to play an important role to help reduce the risk of wildfire and its impact on electric and gas facilities.

Climate scientists predict that climate change will result in varying temperatures and levels of precipitation in the Utility's service territory. This could, in turn, affect the Utility's hydroelectric generation. To plan for this potential change, the Utility is engaging with state and local stakeholders and is also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and collaborating on research and new modeling tools.

With respect to natural gas operations, both safety-related pipeline strength testing and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and volume of natural gas within pipelines prior to venting. In addition, the Utility continues to achieve reductions in methane emissions by implementing improvements in leak detection and repair, upgrades at metering and regulating stations, and maintenance and replacement of other pipeline materials.

Emissions Data

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2018, which is the most recent data available, totaled about 47 million metric tonnes of CO₂ equivalent, more than three-quarters of which came from customer natural gas use. The following table shows the 2018 GHG emissions data the Utility reported to the CARB under AB 32, which is the most recent data available. PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| Source | Amount (metric tonnes CO₂ equivalent) |
|---|---|
| Fossil Fuel-Fired Plants ⁽¹⁾ | 2,512,130 |
| Natural Gas Compressor Stations and Storage Facilities ⁽²⁾ | 299,256 |
| Distribution Fugitive Natural Gas Emissions | 497,299 |
| Customer Natural Gas Use ⁽³⁾ | 41,664,525 |

⁽¹⁾ Includes nitrous oxide and methane emissions from the Utility's generating stations.

⁽²⁾ Includes emissions from compressor stations and storage facilities that are reportable to CARB.

⁽³⁾ Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural gas local distribution companies.

The following table shows the Utility's third-party-verified CO₂ emissions rate associated with the electricity delivered to customers in 2018, which is the most recent data available, as compared to the national average for electric utilities:

| | Amount (pounds of CO₂ per MWh) |
|---|--|
| U.S. Average ⁽¹⁾ | 998 |
| Pacific Gas and Electric Company ⁽²⁾ | 206 |

⁽¹⁾ Source: EPA eGRID.

⁽²⁾ Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's estimated emissions rate.

Air Emissions Data for Utility-Owned Generation

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised more than one-half of the Utility's delivered electricity in 2018. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | 2018 | 2017 |
|---|-------------|-------------|
| Total NOx Emissions (tons) | 134 | 155 |
| NOx Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total SO ₂ Emissions (tons) | 15 | 14 |
| SO ₂ Emissions Rate (pounds/MWh) | 0.001 | 0.001 |

Water Quality

In 2014, the EPA issued final regulations to implement the requirements of the federal Clean Water Act that require cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best technology available to minimize adverse environmental impacts. Various industry and environmental groups challenged the federal regulations and they were upheld by the U.S. Court of Appeals for the Second Circuit. California's once-through cooling policy adopted by the California Water Board in 2010 is considered to be at least as stringent as the new federal regulations and therefore governs implementation in California.

The California Water Board's policy generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The policy also provided for an alternative compliance approach for nuclear plants if certain criteria were met. As required by the policy, the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014. The report addressed feasibility, costs and timeframes to install alternative technologies at Diablo Canyon, such as cooling towers.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon's two nuclear power reactor units at the expiration of their current operating licenses in 2024 and 2025. The CPUC approved the retirement in January 2018. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. As required under the policy, the Utility will continue to pay an annual interim mitigation fee until operations cease in 2025.

Additionally, the Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Regional Water Quality Control Board and the California Attorney General's Office regarding the thermal component of the plant's once-through cooling discharge. (For more information, see "Diablo Canyon Nuclear Power Plant" in Item 3. Legal Proceedings below.)

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. The claim for the period June 1, 2018 through May 31, 2019, totaled approximately \$19 million and is currently under review by the DOE. Amounts reimbursed by DOE are refunded to customers through rates. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results can be affected by many factors, including estimates and assumptions used in the critical accounting policies described in MD&A, that can cause their actual financial results to differ materially from historical results or from anticipated future financial results. The following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with MD&A and the Consolidated Financial Statements and related notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this 2019 Form 10-K. Any of these factors, in whole or in part, could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Risks Related to Chapter 11 Proceedings and Liquidity

PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 and are subject to the risks and uncertainties associated with their bankruptcy cases.

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. For the duration of the Chapter 11 Cases, the financial condition, results of operations, liquidity, and cash flows of PG&E Corporation and the Utility will be subject to various risks, including but not limited to the following:

- the ability to develop, consummate, and implement a plan of reorganization with respect to PG&E Corporation and the Utility during the Chapter 11 Cases that satisfies all applicable legal requirements, including the requirements of AB 1054;
- the ability to develop and obtain applicable Bankruptcy Court, creditor, and regulatory approval of a successful plan of reorganization and the effect of any alternative proposals, views, and objections of official committees, creditors, state and federal regulators, and other stakeholders, which may make it difficult to develop and consummate a successful plan of reorganization in a timely manner and by June 30, 2020;
- the risk that the Noteholder RSA, the Subrogation RSA, the TCC RSA or the PSAs could be terminated;
- the risk that the Backstop Commitment Letters or Debt Commitment Letters could be terminated or that the conditions precedent to funding thereunder are not satisfied or waived;
- the risk that, if the CPUC fails to approve any settlements between PG&E Corporation and the Utility and the CPUC, PG&E Corporation's and the Utility's exit financing may be terminated, making it more difficult for PG&E Corporation and the Utility to emerge from Chapter 11 in a timely manner;
- the ability to obtain Bankruptcy Court approval with respect to certain pending and future motions in the Chapter 11 Cases and the outcomes of Bankruptcy Court rulings and of the Chapter 11 Cases in general;
- risks associated with third-party motions or adversary proceedings in the Chapter 11 Cases, which may interfere with business operations, including additional collateral requirements, or the ability to formulate and implement a plan of reorganization;
- increased costs related to the Chapter 11 Cases and related litigation;
- the ability to maintain or obtain sufficient financing sources for ongoing operations during the pendency of the Chapter 11 Cases or thereafter or to fund a plan of reorganization and meet future obligations, including the initial and annual contributions to the Wildfire Fund and commitments outlined in the Utility's 2020 GRC, 2020-2022 WMP, and other regulatory proceedings;
- the potential for a material decrease in the number of counterparties that are willing to engage in transactions, including commodity-related transactions, with PG&E Corporation or the Utility and a significant increase in the amount of collateral required to engage in any such transactions;
- the potential for a loss of, or a disruption in the materials or services received from, suppliers, contractors or service providers with whom the Utility has commercial relationships or adverse developments in the commercial and financial terms on which such providers engage in such relationships with PG&E Corporation and the Utility;
- risks associated with the potential liability arising from the 2019 Kincadee fire and any other future post-petition wildfires or catastrophic events during the pendency of the Chapter 11 Cases;
- risks associated with claims filed in the Chapter 11 Cases, including claims that have not yet been asserted, that do not specify an amount or in which the asserted amount exceeds the actual value of the claim, which present the potential for delays in the Chapter 11 Cases and which may make it difficult to assess the actual amount of the liability of PG&E Corporation or the Utility;

- risks associated with the potential that the Utility will not be able to comply with the capital structure requirements authorized by the CPUC, to the extent applicable, during the pendency of the Chapter 11 Cases or thereafter;
- potential increased difficulty in retaining and motivating key employees and potential increased difficulty in attracting new employees during the pendency of the Chapter 11 Cases and thereafter, including as a result of the challenging political and operating environment facing the company;
- the significant time and effort required to be spent by senior management in dealing with the Chapter 11 Cases and restructuring activities rather than focusing exclusively on business operations; and
- the ability to continue as a going concern.

PG&E Corporation and the Utility currently are and will continue to be subject to risks and uncertainties with respect to the actions and decisions of creditors and other third parties who have claims or interests in the Chapter 11 Cases that may be inconsistent with PG&E Corporation's and the Utility's plans. These risks and uncertainties could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows in various ways that cannot be predicted and may significantly increase the time PG&E Corporation and the Utility have to operate in Chapter 11. Because of the risks and uncertainties associated with the Chapter 11 Cases, it is not possible to predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases may have on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, nor is it possible to predict the ultimate impact that events occurring during the Chapter 11 Cases may have on PG&E Corporation's and the Utility's corporate and capital structure.

PG&E Corporation and the Utility currently are and will continue to be required to seek approvals of the Bankruptcy Court and certain regulators in connection with the Chapter 11 Cases, and certain parties may object, intervene and protest approval, absent the imposition of terms or conditions to resolve their concerns. Such approvals may be denied, conditioned or delayed.

Operating under Chapter 11 may continue to restrict the ability of PG&E Corporation and the Utility to pursue strategic and operational initiatives.

Under Chapter 11, transactions outside the ordinary course of business are subject to the prior approval of the Bankruptcy Court, which may limit PG&E Corporation's and the Utility's ability to respond in a timely manner to certain events or take advantage of certain opportunities or to adapt to changing market or industry conditions. These limitations include, among other things, PG&E Corporation's and the Utility's ability to:

- make capital investments outside the normal course of business;
- consolidate, merge, sell, or otherwise dispose of assets outside the normal course of business;
- grant liens; and
- finance operations, investments or other capital needs or engage in other business activities, including the ability to achieve California's renewable energy goals.

PG&E Corporation and the Utility may continue to experience increased levels of employee attrition as a result of the filing of the Chapter 11 Cases.

As a result of the filing of the Chapter 11 Cases, PG&E Corporation and the Utility have experienced and may continue to experience increased levels of employee attrition, and their employees will continue to face considerable distraction and uncertainty. A loss of key personnel or material erosion of employee morale could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. PG&E Corporation's and the Utility's ability to engage, motivate and retain key employees or take other measures intended to motivate and incentivize key employees to remain with PG&E Corporation or the Utility, as applicable, through the pendency of the Chapter 11 Cases is limited by restrictions on implementation of retention and incentive programs under the Bankruptcy Code. The loss of members of senior management could impair PG&E Corporation's and the Utility's ability to execute their strategies and implement operational initiatives, which would likely have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

As a result of the Chapter 11 Cases, PG&E Corporation's and the Utility's historical financial information may not be indicative of future financial performance.

PG&E Corporation's and the Utility's capital structure will likely be significantly altered under any plan of reorganization confirmed by the Bankruptcy Court. Under fresh-start accounting rules that may apply to PG&E Corporation and the Utility upon the effective date of a plan of reorganization, their assets and liabilities would be adjusted to fair value. Accordingly, if fresh-start accounting rules apply, PG&E Corporation's and the Utility's financial condition and results of operations following emergence from Chapter 11 would not be comparable to the financial condition and results of operations reflected in their historical financial statements. In connection with the Chapter 11 Cases and the development of a plan of reorganization, it is also possible that additional restructuring and related charges may be identified and recorded in future periods. Such charges could be material to PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

If PG&E Corporation and the Utility are not able to consummate a consensual plan of reorganization, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by a protracted restructuring.

PG&E Corporation and the Utility commenced the Chapter 11 Cases without the benefit of a restructuring support agreement or agreed consensual plan of reorganization with any of its creditors or other key constituents. On October 17, 2019, the TCC and the Ad Hoc Noteholder Committee filed their competing Ad Hoc Noteholder Plan. In connection with the Noteholder RSA (as defined below), the competing Ad Hoc Noteholder Plan was withdrawn on February 5, 2020. If the Noteholder RSA were to be terminated, or if a new competing plan of reorganization were filed by any constituents, the resulting competing plan process could reduce the likelihood that the plan of reorganization that is ultimately confirmed by the Bankruptcy Court is the Proposed Plan and, in any event, could have a material effect on PG&E Corporation's and the Utility's ability to achieve confirmation of a plan of reorganization that would enable PG&E Corporation and the Utility to reach their stated goals. Additionally, any RSAs entered into in connection with the Chapter 11 Cases are likely to be highly conditional on circumstances outside the control of PG&E Corporation and the Utility.

Accordingly, no assurance can be provided as to the length of time during which the Chapter 11 Cases will be pending, whether the Proposed Plan can be successfully consummated, how the terms of the Proposed Plan may change, whether the Proposed Plan will be the plan of reorganization that is ultimately consummated, how the proposed post-emergence capital structure may change, and what the effect of the Proposed Plan or any other plan of reorganization that is confirmed would have on PG&E Corporation and the Utility or on any of their respective equity, debt and other stakeholders, including as to matters of taxation and recovery or distributions upon consummation of any plan of reorganization.

Even if PG&E Corporation and the Utility are successful in obtaining confirmation of the Proposed Plan, the process has been, and will continue to be lengthy, costly and disruptive. A contested plan of reorganization proceeding would likely have a more pronounced material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows than a consensual plan of reorganization. Even if PG&E Corporation and the Utility are able to obtain requisite stakeholder approval, the Bankruptcy Court may not confirm a plan of reorganization.

The uncertainty surrounding the prolonged restructuring may also have other material effects on PG&E Corporation and the Utility including, but not limited to:

- the ability of PG&E Corporation and the Utility to raise additional capital;
- PG&E Corporation's and the Utility's liquidity;
- how PG&E Corporation's and the Utility's business is viewed by regulators, investors, lenders and credit ratings agencies;
- the ability of PG&E Corporation and the Utility to make capital expenditures, including to invest in initiatives necessary to ensure the continued safe operation of the business;
- whether the Utility can qualify for the benefits under AB 1054, including obtaining the required state approvals by the statutory deadline;
- whether PG&E Corporation is required to transfer control or ownership of the Utility or its business to a third party, such as the State of California or a third party monitor or receiver that is not accountable to PG&E Corporation's board of directors or shareholders;

- PG&E Corporation's and the Utility's enterprise value; and
- PG&E Corporation's and the Utility's ability to continue as a going concern.

PG&E Corporation and the Utility may be subject to claims that will not be discharged in their Chapter 11 Cases, which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all claims arising prior to its filing under Chapter 11. With few exceptions, all claims that arose prior to PG&E Corporation's and the Utility's Chapter 11 Cases: (i) would be subject to compromise and/or treatment under the plan of reorganization and (ii) would be discharged in accordance with the Bankruptcy Code and the terms of the plan of reorganization. PG&E Corporation and the Utility face several significant potential liabilities that arose after the start of the Chapter 11 Cases, including potential liabilities associated with the 2019 Kincadee fire and the PSPS Program. Any claims not ultimately discharged through a plan of reorganization could be asserted against the reorganized entities and may have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows on a post-reorganization basis and may cast substantial doubt on PG&E Corporation's and the Utility's ability to continue as a going concern.

The DIP Facilities may be insufficient to fund PG&E Corporation's and the Utility's cash requirements through their emergence from bankruptcy.

PG&E Corporation's and the Utility's liquidity, including PG&E Corporation's and the Utility's ability to meet their ongoing operational obligations, is dependent upon, among other things: (i) PG&E Corporation's and the Utility's ability to comply with the terms and conditions of any post-petition financing and cash collateral order entered by the Bankruptcy Court in connection with the Chapter 11 Cases, including the financing orders entered with respect to the DIP Credit Agreement, (ii) PG&E Corporation's and the Utility's ability to maintain adequate cash on hand, (iii) PG&E Corporation's and the Utility's ability to generate cash flow from operations, (iv) PG&E Corporation's and the Utility's ability to develop, confirm and consummate a plan of reorganization or other alternative restructuring transaction and (v) the cost, duration and outcome of the Chapter 11 Cases. For the duration of the Chapter 11 Cases, PG&E Corporation and the Utility will be subject to various risks, including but not limited to (i) the inability to maintain or obtain sufficient financing sources for operations or to fund any plan of reorganization and meet future obligations, and (ii) increased legal and other professional costs associated with the Chapter 11 Cases and the reorganization.

PG&E Corporation and the Utility have entered into the DIP Credit Agreement. On March 27, 2019, the Bankruptcy Court approved the DIP Facilities (as defined below) on a final basis, authorizing the Utility to borrow up to the full amount of the DIP Revolving Facility (including the full amount of the \$1.5 billion letter of credit subfacility), the DIP Initial Term Loan Facility and the DIP Delayed Draw Term Loan Facility (as defined below), in each case subject to the terms and conditions of the DIP Credit Agreement. For the duration of the Chapter 11 Cases, PG&E Corporation and the Utility expect that the DIP Credit Agreement, together with cash on hand and cash flow from operations, will be the Utility's primary source of capital to fund ongoing operations and other capital needs and that they will have limited, if any, access to additional financing. For more information on the DIP Credit Agreement, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

The DIP Credit Agreement will mature on December 31, 2020, subject to the Utility's option to extend the maturity to December 31, 2021 if certain terms and conditions are satisfied, including the payment of an extension fee.

PG&E Corporation and the Utility have faced and will continue to face uncertainty regarding the adequacy of their liquidity and capital resources during the pendency of the Chapter 11 Cases, and have limited, if any, access to additional financing. PG&E Corporation and the Utility cannot provide assurance that cash on hand, cash flow from operations, distributions received from their subsidiaries and borrowings available under the DIP Credit Agreement will be sufficient to continue to fund operations during the pendency of the Chapter 11 Cases. Although the DIP Credit Agreement is expected to be sufficient to address liquidity needs for the expected duration of the Chapter 11 Cases, if the Chapter 11 Cases last longer than expected (particularly if the Proposed Plan is not confirmed by June 30, 2020) there can be no assurance that the DIP Credit Agreement will provide adequate liquidity for such scenario. The ability of PG&E Corporation and the Utility to maintain adequate liquidity depends in part upon industry conditions and general economic, financial, competitive, regulatory and other factors beyond their control. In the event that cash on hand, cash flow from operations, distributions received from subsidiaries and availability under the DIP Credit Agreement are not sufficient to meet these liquidity needs, PG&E Corporation and the Utility may be required to seek additional financing, and can provide no assurance that additional financing would be available or, if available, offered on acceptable terms.

The DIP Credit Agreement imposes a number of restrictions on PG&E Corporation and the Utility that may, among other things, limit their ability to conduct their business, or pursue new business opportunities and strategies. Additionally, PG&E Corporation and the Utility may be unable to comply with the covenants imposed by the DIP Credit Agreement. Such non-compliance could result in an event of default under the DIP Credit Agreement that, if not cured or waived, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The DIP Credit Agreement imposes a number of restrictions on PG&E Corporation and the Utility, including, among other things, affirmative covenants requiring PG&E Corporation and the Utility to provide financial information, cash flow forecasts, variance reports and other information to the administrative agent. The DIP Credit Agreement also contains general affirmative covenants such as compliance with all applicable laws, maintenance of licenses from necessary governmental authorities, maintenance of property and preservation of corporate existence. Negative covenants contained in the DIP Credit Agreement include restrictions on 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. The Utility's ability to borrow under the DIP Credit Agreement is subject to the satisfaction of certain customary conditions precedent set forth therein. For more information on the DIP Credit Agreement, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

As a result of these covenants and restrictions, PG&E Corporation and the Utility may be limited in their ability to conduct their business, and respond to changing business, market, and economic conditions. These provisions may also limit PG&E Corporation's and the Utility's ability to pursue new business opportunities and strategies.

PG&E Corporation's and the Utility's ability to comply with these provisions may be affected by events beyond their control and their failure to comply, or obtain a waiver in the event PG&E Corporation or the Utility cannot comply with a covenant, could result in an event of default under the agreements governing the DIP Credit Agreement that, if not cured or waived, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Backstop Commitment Letters and the Debt Commitment Letters provide a number of conditions precedent to the obligations of the Backstop Parties and the Commitment Parties to fund the Proposed Plan as well as a number of termination rights for the Backstop Parties and the Commitment Parties. There can be no assurance that the conditions precedent will be satisfied or waived, or that events or circumstances will not occur that give rise to the termination rights. If the conditions precedent to funding cannot be satisfied or waived, or if the Backstop Commitment Letters or the Debt Commitment Letters are terminated, it could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Backstop Commitment Letters impose a number of conditions that must be satisfied before the Backstop Parties are obligated to fund the Proposed Plan. In addition, the Backstop Parties have certain termination rights under the Backstop Commitment Letters, which may be triggered by events beyond the control of PG&E Corporation and the Utility. The Debt Commitment Letters are also subject to numerous conditions precedent and termination rights, including certain conditions precedent and termination rights similar to those included in the Backstop Commitment Letters, as well as certain other conditions precedent, including that the Utility shall have received investment grade senior secured debt ratings. For more information on the Backstop Commitment Letters and the Debt Commitment Letters, including a summary of conditions precedent and termination rights, see "Plan of Reorganization, RSAs, Equity Backstop Commitments and Debt Commitment Letters" in Note 2 of the Notes to the Consolidated Financial Statements.

If PG&E Corporation and the Utility fail to complete a monetization transaction utilizing any net operating losses or tax deductions resulting from the payment of pre-petition wildfire-related claims as contemplated in the Backstop Commitment Letters, 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, and PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

There can be no assurance that the conditions precedent set forth in the Backstop Commitment Letters or the Debt Commitment Letters will be satisfied or waived, or that events or circumstances will not occur that give rise to termination rights of the Backstop Parties or the Commitment Parties, which may be beyond the control of PG&E Corporation and the Utility.

If the conditions precedent to funding under the Backstop Commitment Letters or the Debt Commitment Letters cannot be satisfied or waived, or if the Backstop Commitment Letters or Debt Commitment Letters are terminated, PG&E Corporation's and the Utility's ability to finance the Proposed Plan could be jeopardized, which could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Additionally, there can be no assurance that PG&E Corporation and the Utility would be able to obtain alternative financing to the transactions contemplated by the Backstop Commitment Letters and the Debt Commitment Letters.

PG&E Corporation's and the Utility's Consolidated Financial Statements have been prepared assuming that PG&E Corporation and the Utility will continue as going concerns. PG&E Corporation and the Utility are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred during the past several years. Uncertainty regarding these matters raises substantial doubt about PG&E Corporation's and the Utility's abilities to continue as going concerns. In addition, there is inherent uncertainty regarding the outcome of the Chapter 11 Cases. PG&E Corporation and the Utility have not included any financial statement adjustments that might result from the outcome of these uncertainties.

The accompanying Consolidated Financial Statements to this Annual Report on Form 10-K have been prepared assuming that PG&E Corporation and the Utility will continue as going concerns. 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. Management has concluded that these circumstances raise substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns, and their independent registered public accountants have included an explanatory paragraph in their auditors' report which states certain conditions exist that raise substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns in relation to the foregoing. In addition, there is inherent uncertainty regarding the outcome of the Chapter 11 Cases. For further discussion of such uncertainty, see the risk factors above in "Risks Related to Chapter 11 Proceedings and Liquidity" in this Item 1A. PG&E Corporation's and the Utility's plans in regard to these matters are described in Note 2 of the Notes to the Consolidated Financial Statements in Item 8. The Consolidated Financial Statements do not include any adjustments that might result from the outcome of these uncertainties. See "Report of Independent Registered Public Accounting Firm" in Item 8.

Trading in PG&E Corporation's and the Utility's securities during the pendency of the Chapter 11 Cases is highly speculative and poses substantial risks.

Trading in PG&E Corporation's and the Utility's securities during the pendency of the Chapter 11 Cases is highly speculative and poses substantial risks. The ultimate recovery, if any, by holders of PG&E Corporation's or the Utility's securities in the Chapter 11 Cases could differ substantially from any value that may be implied by the trading prices of such securities at any particular time during the pendency of the Chapter 11 Cases.

Risks Related to Wildfires

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the 2018 Camp fire, the 2017 Northern California wildfires and other pre-petition fires (including the 2015 Butte fire), notwithstanding the commencement of the Chapter 11 Cases.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the 2018 Camp fire, the 2017 Northern California wildfires and other pre-petition fires (including the 2015 Butte fire), notwithstanding the commencement of the Chapter 11 Cases. As disclosed below in Note 14 of the Notes to Consolidated Financial Statements in Item 8, PG&E Corporation and the Utility are subject to numerous lawsuits in connection with the 2018 Camp fire, the 2017 Northern California wildfires and other pre-petition fires by various plaintiffs, including wildfire victims, insurance carriers, and various government entities, under multiple theories of liability. These lawsuits generally assert that the Utility's alleged failure to maintain and repair its distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the 2018 Camp fire and 2017 Northern California wildfires.

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. PG&E Corporation's and the Utility's obligations with respect to such claims are expected to be determined through the Chapter 11 process. If the Subrogation RSA, TCC RSA or PSAs were to be terminated and litigation relating to the 2018 Camp fire, the 2017 Northern California wildfires and other pre-petition wildfires were to recommence, and the Utility's facilities, such as its electric distribution and transmission lines, were 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, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility, including on PG&E Corporation's and the Utility's ability to develop and consummate a successful plan of reorganization. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows" below.) In addition to such 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, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility, including on PG&E Corporation's and the Utility's ability to develop and consummate a successful plan of reorganization.

Although PG&E Corporation and the Utility have entered into settlement agreements to resolve the claims of the major classes of claimholders, including Utility debtholders, individual wildfire victims, holders of subrogated insurance claims and certain public entities, non-consenting claimholders may still be able to challenge and otherwise impede the Proposed Plan. These settlement agreements could be terminated under various circumstances, some of which are beyond the PG&E Corporation's and the Utility's control. As described below in Note 14 of the Notes to Consolidated Financial Statements in Item 8, PG&E Corporation and the Utility have entered into agreements with major claimholders or their representatives to settle all pre-petition liabilities related to the 2018 Camp fire and 2017 Northern California wildfires (and in certain cases, other pre-petition fires) for an aggregate amount of \$25.5 billion. These agreements are subject to numerous conditions and termination rights in favor of third parties, including, among others, (i) certain breaches by PG&E Corporation or the Utility, (ii) if PG&E Corporation or the Utility become insolvent, (iii) if the Proposed Plan is inconsistent with the terms of these agreements, (iv) if certain milestones are not met and (v) failure of the Proposed Plan or the treatment of claims contemplated thereby to be consistent with AB 1054. Certain of these agreements contain additional termination rights that are beyond the control of PG&E Corporation or the Utility. For example, the PSA with Supporting Public Entities may be terminated by the Supporting Public Entities if FEMA or the OES fail 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. 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.

In addition, 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. If FEMA, OES/Cal Fire, or other government entities that are not Supporting Public Entities do not support the Proposed Plan or treatment of their Fire Victim Claims, such claims could be material to PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. 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.

Absent the settlement agreements noted above, potential liabilities related to the 2018 Camp fire and 2017 Northern California wildfires depend on various factors, including, but not limited to, the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the extent to which future claims arise, the amount of fire suppression and clean-up costs and other damages the Utility may be responsible for if found negligent. Notwithstanding the Bar Date and the settlement agreements entered into as of the date of this filing, there remain a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility and the treatment of such claims in the Chapter 11 Cases.

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 that may be imposed by government entities on PG&E Corporation and the Utility, the amount of such punitive damages, fines, penalties or restitution orders that may result from any criminal charges brought could be significant and could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, as well as PG&E Corporation's and the Utility's ability to develop and consummate a successful plan of reorganization. In connection with the Wildfires OII, the Utility has agreed to remedies that will result in substantial capital expenditures that will not be subject to cost recovery. The Utility has 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 natural gas explosion that occurred in the City of San Bruno 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 or 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.

In addition, PG&E Corporation and the Utility could be the subject of additional lawsuits on account of obligations arising after the commencement of the Chapter 11 Cases and of additional investigations, citations, fines or enforcement actions in connection with the 2018 Camp fire and 2017 Northern California wildfires.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected as a result of the 2019 Kincade fire and any future post-petition wildfire during the pendency of the Chapter 11 Cases.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected as a result of the 2019 Kincade fire and future post-petition wildfires during the pendency of the Chapter 11 Cases.

As described below in Note 14 to the Consolidated Financial Statements under the heading "2019 Kincade fire," 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. PG&E Corporation and the Utility have received and are responding to data requests from the CPUC's SED relating to the Kincade fire. PG&E Corporation and the Utility could be the subject of additional investigations, lawsuits, or enforcement actions in connection with the 2019 Kincade fire.

Additionally, regardless of whether the Utility is ultimately determined to have caused the 2019 Kincade fire or any future post-petition wildfire during the pendency of the Chapter 11 Cases, PG&E Corporation's and the Utility's bankruptcy timing and process and the ability of the Utility to participate in the Wildfire Fund could be materially affected as a result of claims arising out of the 2019 Kincade fire. PG&E Corporation's and the Utility's ability to consummate the Proposed Plan by June 30, 2020 (or at all) could be impaired, and PG&E Corporation and the Utility may not be able to amend the Proposed Plan, or develop another alternative to the Proposed Plan, that could be confirmed by June 30, 2020 or at all. The Backstop Commitment Letters and the Debt Commitment Letters contain certain conditions precedent and termination rights that could be implicated by the 2019 Kincade fire and any future post-petition wildfire during the pendency of the Chapter 11 Cases. PG&E Corporation and the Utility may not be able to satisfy, or obtain a waiver of, such conditions precedent to the commitments, or the Backstop Parties or the Commitment Parties, respectively, may have the right to terminate such commitments, which would jeopardize PG&E Corporation's and the Utility's ability to finance the Proposed Plan. PG&E Corporation and the Utility may not be able to obtain alternative financing to the transactions contemplated by the Backstop Commitment Letters and the Debt Commitment Letters, and may not be able to obtain financing for an alternative plan that may be proposed by PG&E Corporation and the Utility after the impact of the 2019 Kincade fire is better known.

Finally, the 2019 Kincade fire or a future post-petition wildfire could have adverse consequences on the Utility's probation proceeding, the Utility's proceedings with the CPUC and FERC (including the Safety Culture OII and the Chapter 11 Proceedings OII), the criminal investigation into the 2018 Camp fire and future regulatory proceedings, including future applications for the safety certification required by AB 1054. PG&E Corporation and the Utility may also suffer additional reputational harm and face an even more challenging operating, political, and regulatory environment. For more information about the 2018 Camp fire and 2017 Northern California wildfires, see "2018 Camp fire and 2017 Northern California wildfires" in Note 14 of the Notes to Consolidated Financial Statements in Item 8.

The amount of potential losses resulting from the impact of the 2018 Camp fire and 2017 Northern California wildfires is expected to greatly exceed the amount of PG&E Corporation's and the Utility's insurance coverage for wildfire events. The amount of potential losses resulting from the impact of the 2019 Kincade fire could also exceed the amount of PG&E Corporation's and the Utility's insurance coverage for wildfires. Securing liability insurance in future years is expected to be increasingly difficult and expensive, if available at all.

The amount of potential losses resulting from the impact of the 2018 Camp fire and 2017 Northern California wildfires is expected to greatly exceed the amount of PG&E Corporation's and the Utility's insurance coverage for wildfire events. The amount of potential losses resulting from the impact of the 2019 Kincade fire could also exceed the amount of PG&E Corporation's and the Utility's insurance coverage for wildfire events. Even if the Utility satisfies the eligibility and other requirements to participate in the Wildfire Fund under AB 1054, the recovery of any such excess losses from the Wildfire Fund would be capped at 40%.

PG&E Corporation and the Utility had 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. Further, PG&E Corporation and the Utility have 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 \$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. In addition, coverage limits within these wildfire insurance policies could result in further material self-insured costs in the event each fire were deemed to be a separate occurrence under the terms of the insurance policies.

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. 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. In addition, PG&E Corporation and the Utility expect their losses in connection with the 2018 Camp fire and 2017 Northern California wildfires will greatly exceed their available insurance, and the Utility could also be subject to significant liability in excess of insurance in connection with the 2019 Kincade fire. For a discussion of the potential magnitude of PG&E Corporation's and the Utility's liability, see "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the 2018 Camp fire and the 2017 Northern California wildfires and other pre-petition fires (including the 2015 Butte fire), notwithstanding the commencement of the Chapter 11 Cases" and "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected as a result of the 2019 Kincade fire and any future post-petition wildfire during the pendency of the Chapter 11 Cases." above.

PG&E Corporation and the Utility also expect to face increasing difficulty securing liability insurance in future years due to availability and to face significantly increased insurance costs.

If the Utility is unable to recover all or a significant portion of its excess costs in connection with the 2019 Kincade fire, the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire through ratemaking mechanisms and in a timely manner, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

As of December 31, 2019, the Utility incurred substantial costs in connection with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire in excess of costs currently in rates, some of which currently are or are expected to be recorded in the future in its WEMA account. The Utility could similarly incur substantial costs in excess of insurance coverage in the future in connection with the 2019 Kincade fire.

There can be no assurance that the Utility will be allowed to recover costs in excess of insurance, including costs recorded in those accounts in the future, 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.

SB 901, signed into law on September 21, 2018, required 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 authorized 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, as the bill does not address fires that occurred in 2018.

After a CPUC July 8, 2019 decision determined that a utility that has filed for relief under Chapter 11 cannot access the CHT, on August 7, 2019, the Utility submitted to the CPUC an application for rehearing of that decision, the outcome of which is uncertain. For more information on the OIR, see “OIR to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901” in Item 7. MD&A.

The inability to recover all or a significant portion of costs in excess of insurance through increases in rates and by collecting such rates 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.

PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected in the event of further non-compliance with the terms of probation or in the event of further modifications to the conditions of probation.

PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected in the event of further non-compliance with the terms of probation or in the event of further modifications to the conditions of probation. On January 26, 2017, following the federal criminal trial against the Utility in connection with the San Bruno explosion, in which the Utility was found guilty on six felony counts, the Utility was sentenced to, among other things, a five-year corporate probation period and oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years. The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility has retained a third-party monitor at the Utility’s expense. The goal of the third-party monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations, and to maintain effective ethics, compliance and safety related incentive programs on a Utility-wide basis.

In 2018 and 2019, the court overseeing the Utility’s probation issued various orders related to the Utility’s probation, including a finding that the Utility had violated a condition of its probation with respect to reporting requirements, and imposing new conditions of probation. For more information about the Utility’s probation and the court’s orders, see “U.S. District Court Matters and Probation” in Item 3. Such proceedings are not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases.

The Utility could incur material costs, not recoverable through rates, in the event of further non-compliance with the terms of its probation and in connection with the monitorship (including but not limited to costs resulting from recommendations of the third-party monitor). The Utility could also incur material costs, not recoverable through rates, in the event of further modifications to the conditions of its probation, such as those proposed by the court overseeing the Utility’s probation on January 16, 2020, relating to the hiring of additional contractors to ensure full compliance with certain vegetation management conditions.

The outcome of probation could harm the Utility’s relationships with customers, regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, it could negatively affect the outcome of future ratemaking and regulatory proceedings and result in increased regulatory or legislative scrutiny, including with respect to various aspects of how the Utility’s business is conducted or organized. (See “Enforcement and Litigation Matters” in Item 7. MD&A.)

The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

California law includes a doctrine of inverse condemnation that is routinely invoked in California. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages as a result of the design, construction and maintenance of utility facilities, including utilities' electric transmission lines. Courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Plaintiffs have asserted the doctrine of inverse condemnation in lawsuits related to the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire, and courts have ruled that the doctrine can apply to PG&E Corporation and the Utility in those matters. While the Utility currently continues to litigate this issue, there can be no assurance that the Utility will be successful in overturning the rulings that inverse condemnation applies in the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire or other litigation against PG&E Corporation or the Utility.

Furthermore, a court could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. Although the imposition of liability under the doctrine of inverse condemnation is premised on the assumption that utilities have the ability to automatically recover these costs from their customers, there can be no assurance that the CPUC would authorize cost recovery whether or not a previous court decision had imposed liability on a utility under the doctrine of inverse condemnation. (In December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC's prudent manager standard. That determination was challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison. In October 2019, the U.S. Supreme Court declined to review the case, effectively ending the challenge.)

If PG&E Corporation or the Utility were to be found liable for damages under the doctrine of inverse condemnation, but the Utility was unable to secure a cost recovery decision from the CPUC to pay for such costs through increases in rates or to collect such rates in a timely manner, the financial condition, results of operations, liquidity, and cash flows of PG&E Corporation and the Utility would be materially affected by potential losses resulting from the impact of the 2019 Kincadee fire, and, if the TCC RSA, Subrogation RSA, or PSAs were to be terminated, the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire. (See "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the 2018 Camp fire, the 2017 Northern California wildfires and other pre-petition fires (including the 2015 Butte fire), notwithstanding the commencement of the Chapter 11 Cases," and "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected as a result of the 2019 Kincadee fire and any future post-petition wildfire during the pendency of the Chapter 11 Cases" above.)

PG&E Corporation's and the Utility's financial results could be materially affected as a result of the Utility's implementation of its PSPS program.

As outlined in the 2019 Wildfire Mitigation Plan, PG&E Corporation and the Utility have adopted the PSPS program to proactively de-energize lines that traverse areas under elevated and extreme risks for wildfire when forecasts predict extreme fire-threat conditions. In addition to the 2019 PSPS events, the Utility expects that PSPS events will be necessary in 2020 and future years. Approximately 5.4 million electric customer premises may potentially be impacted by PSPS events.

Since June 2019, PG&E Corporation and the Utility have carried out several PSPS events. These PSPS events have been subject to significant scrutiny and criticism by various stakeholders, including the California Governor, the CPUC and the court overseeing the Utility's probation. On November 12, 2019, the CPUC issued an order to show cause why the Utility should not be sanctioned for alleged violations of law related to its communications with customers, coordination with local governments, and communications with critical facilities and public safety partners during the PSPS events in late 2019. On November 13, 2019, the CPUC instituted an OII to examine 2019 PSPS events carried out by California's investor-owned utilities and to consider enforcement actions. The Utility also is the subject of a class action litigation in connection with the 2019 PSPS events that was filed in the Bankruptcy Court in December of 2019. On January 24, 2020, the assigned ALJ issued a proposed decision in the 2020 Energy Resource Recovery Account (ERRA) Forecast proceeding that, if finalized, would require the Utility to include in its application for the 2019 ERRA Compliance Review an accounting of the PSPS events that occurred in its service territory in 2019 and how the PSPS impacted its revenue collections. Also, on January 27, 2020, the California state senate approved SB 378 that, if passed by the assembly and then enacted into law, would require the CPUC, on or before June 1, 2021, to establish a procedure for customers, local governments, and others affected by a de-energization event to recover specified costs incurred as a result of the de-energization event from an electrical corporation within specified time periods. The bill would also require the CPUC to establish rules determining whether these payments can be recovered from ratepayers.

In addition, the proposal of SB 378, which would impose penalties and other requirements on electric utility companies relating to PSPS events, 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 to other requirements, SB 378 would impose on an electric utility company a civil penalty of at least \$250,000 per 50,000 affected customers for every hour that a PSPS event is in place, would require the CPUC to establish a procedure for customers, local governments and others to recover specified costs incurred during a PSPS event from the electric utility company, which cost recovery would be borne by shareholders, and would prohibit an electric utility company from billing customers for any nonfixed costs during a PSPS event.

Further, the proposals of AB 1941 could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. AB 1941 proposes to suspend RPS requirements, determine the savings to electric utility companies from the suspension and direct those savings towards system hardening to mitigate wildfire risks and PSPS impacts, and would prohibit salary increases or bonuses to executive officers during the suspension of RPS requirements.

PG&E Corporation and the Utility cannot predict the timing and outcome of the OII, order to show cause, the class action litigation, and pending litigation. PG&E Corporation and the Utility could be subject to additional investigations, regulatory proceedings or other enforcement actions as well as to additional litigation and claims by customers as a result of the Utility's implementation of its PSPS program, including with respect to the October 9, 2019 PSPS event, which could result in fines, penalties, customer rebates or other payments. The amount of any fines, penalties, customer rebates or other payments (if PG&E Corporation or the Utility were to issue any credits, rebates or other payments in connection with any other PSPS events (whether past events or in the future)) or liability for damages 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 PSPS program has had an adverse impact on PG&E Corporation's and the Utility's reputation with customers, regulators and policymakers and future PSPS events may increase these negative perceptions.

Risks Related to the Outcome of Other Enforcement Matters, Investigations, and Regulatory Proceedings

PG&E Corporation's and the Utility's financial results could be materially affected as a result of legislative and regulatory developments.

The Utility's financial results could be materially affected as a result of SB 901 adopted in 2018 by the California legislature. In December 2018, the CPUC opened an OIR in connection with SB 901 that will adopt criteria and a methodology for use by the CPUC in future applications for cost recovery of wildfire costs. After a CPUC July 8, 2019 decision determined that a utility that has filed for relief under Chapter 11 cannot access the CHT, on August 7, 2019, the Utility submitted to the CPUC an application for rehearing of that decision, the outcome of which is uncertain. 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. (See "Regulatory Matters - Other Regulatory Proceedings" in Item 7. MD&A.)

In addition, SB 901 requires utilities to submit annual wildfire mitigation plans for approval by the CPUC on a schedule to be established by the CPUC. SB 901 establishes factors to be considered by the CPUC when setting penalties for failure to substantially comply with the plan. Failure to substantially comply with the plan could result in fines and other penalties imposed on the Utility that could be material. (See "Regulatory Matters – Other Regulatory Proceedings" in Item 7. MD&A.)

On July 12, 2019, the California Governor signed into law AB 1054, which, among other policy reforms, provides for the establishment of a statewide fund that is 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. Although PG&E Corporation and the Utility have delivered notice to the CPUC electing to participate in the Wildfire Fund and even if the Utility were eligible to do so, the impact of AB 1054 on PG&E Corporation and the Utility is subject to numerous uncertainties, including the Utility's ability to demonstrate to the CPUC that wildfire-related costs paid from the Wildfire Fund are just and reasonable, subject to a disallowance cap, and that the Wildfire Fund has sufficient remaining funds.

The costs of participating in the Wildfire Fund (should the Utility be eligible to do so) are expected to exceed \$6.7 billion over the anticipated ten-year life of the fund. The timing and amount of any potential charges associated with shareholder contributions would also depend on various factors, including the timing of resolution of the Chapter 11 Cases. In addition, there could also be a significant delay between the occurrence of a wildfire and the timing on 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 participating electric utility. Participation in the Wildfire Fund is expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows, and there can be no assurance that the benefits of participating in the Wildfire Fund ultimately outweigh these substantial costs.

Finally, AB 1054 revised some of the SB 901 requirements regarding wildfire mitigation plans, including creating a Wildfire Safety Division to review future plans and that plans should cover a three-year period.

Also, in June 2018, the State of California enacted the CCPA, which went into effect on January 1, 2020, with a 12-month look-back period requiring compliance by January 1, 2019. On October 11, 2019, the State of California announced proposed regulations which provide guidance on the requirements of the CCPA. The CCPA requires companies that process information on California residents to make new disclosures to consumers about their data collection, use and sharing practices, allows consumers to opt out of certain data sharing with third parties and provides a new cause of action for data breaches. The CCPA provides for financial penalties in the event of non-compliance and statutory damages in the event of a data security breach. Failure to comply with the CCPA could result in fines imposed on PG&E Corporation and the Utility that could be material.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the ability of PG&E Corporation and the Utility to participate in the Wildfire Fund under AB 1054, which is subject to numerous uncertainties and which could involve significant organizational or governance changes.

The Utility's ability to participate in the Wildfire Fund is subject to numerous eligibility and other requirements set forth in AB 1054, including, among others, (a) the Utility's Chapter 11 Case has been resolved pursuant to a plan of reorganization by June 30, 2020, (b) the CPUC has approved the Utility's plan of reorganization, 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, and (c) the CPUC has determined that the Utility's plan of reorganization is (i) consistent with California's climate goals and (ii) neutral, on average, to the Utility's ratepayers. (See "Assembly Bill 1054" in Item 7. MD&A.) There can be no assurance that PG&E Corporation and the Utility will be able to meet these eligibility and other requirements for participating in the Wildfire Fund, including that the CPUC will issue the necessary approvals or make the necessary determinations.

On October 4, 2019, the CPUC issued an OII to consider the ratemaking and other implications "that will result from the confirmation of a plan of reorganization and other regulatory approvals necessary to resolve" the Chapter 11 Cases (the "Chapter 11 Proceedings OII"). The scope of the Chapter 11 Proceedings OII includes, among others, any regulatory approvals required in order for PG&E Corporation and the Utility to become eligible to participate in the Wildfire Fund and any other regulatory approvals required by AB 1054. PG&E Corporation and the Utility cannot predict the outcome of the Chapter 11 Proceedings OII.

Additionally, PG&E Corporation's and the Utility's ability to meet the eligibility and other requirements may be adversely impacted by the California Governor's review of the Proposed Plan that PG&E Corporation and the Utility filed with the Bankruptcy Court on January 31, 2020.

Failure to meet the eligibility conditions to access relief under the Wildfire Fund, including satisfaction of the eligibility requirements described above and the Utility making its initial contribution thereto, would preclude PG&E Corporation and the Utility from accessing the Wildfire Fund for future wildfire-related claims and any related benefits, including the disallowance cap, and 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 is subject to extensive regulations and the risk of enforcement proceedings in connection with compliance with such regulations. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the outcomes of the CPUC's investigative enforcement proceedings against the Utility, other known enforcement matters, and other ongoing state and federal investigations and requests for information.

The Utility is subject to extensive regulations, including federal, state and local energy, environmental and other laws and regulations, and the risk of enforcement proceedings in connection with compliance with such regulations. The Utility could incur material charges, including fines and other penalties, in connection with the Wildfires OII, the locate and mark OII, the order to show cause related to the 2019 PSPS events, the safety culture OII, and other matters that the CPUC's SED may be investigating. The SED could launch investigations at any time on any issue it deems appropriate. Such proceedings are likely not subject to the automatic stay imposed as a result of the commencement of the Chapter 11 Cases; however, collection efforts in connection with fines or penalties arising out of such proceedings are stayed.

The SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it may impose the maximum statutory penalty of \$50,000, per penalty, per day, with an administrative limit of \$8 million per citation issued. For offenses occurred after January 1, 2019, the maximum statutory penalty is \$100,000, per penalty, per day. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED may also issue multiple citations per violation or address multiple violations in a single citation. While it is uncertain how the CPUC would calculate the number of violations or the penalty for any violations, such fines or penalties could be significant and materially affect PG&E Corporation's and the Utility's liquidity and results of operations. (See "Regulatory Environment" in Item 1. Business and Note 15 to the Consolidated Financial Statements in Item 8.)

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and resource adequacy requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; compliance with CPUC general orders or other applicable CPUC decisions or regulations; federal electric reliability standards; and environmental compliance. CPUC staff could also impose penalties on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds 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 also is a target of a number of investigations, in addition to certain investigations in connection with the wildfires. (See "Risks Related to Wildfires," above.) The Utility is unable to predict the outcome of pending investigation, including whether any charges will be brought against the Utility, or the amount of any costs and expenses associated with such investigations.

If these investigations result in enforcement action against the Utility, the Utility could incur additional fines or penalties the amount of which could be substantial and, in the event of a judgment against the Utility, suffer further ongoing negative consequences. Furthermore, a negative outcome in any of these investigations, or future enforcement actions, could negatively affect the outcome of future ratemaking and regulatory proceedings to which the Utility may be subject; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations. (See also "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected in the event of non-compliance with the terms of probation or in the event of modifications to the conditions of probation" above.)

PG&E Corporation's and the Utility's financial results primarily depend on the outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its operating expenses and capital expenditures so that it is able to earn its authorized rate of return in a timely manner.

As a regulated entity, the Utility's rates are set by the CPUC or the FERC on a prospective basis and are generally designed to allow the Utility to collect sufficient revenues to recover reasonable costs of providing service, including a return on its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and affordable electric and gas services. Further, an increase in the amount of capacity located in the Utility's service territory that is procured by the CAISO under Reliability Must Run ("RMR") contracts could increase the Utility's costs of procuring capacity needed for reliable service to its customers.

In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial results could be materially affected if the Utility's actual costs to safely and reliably serve its customers differ from authorized or forecast costs. The Utility may incur additional costs for many reasons including changing market circumstances, unanticipated events (such as wildfires, storms, earthquakes, accidents, or catastrophic or other events affecting the Utility's operations), or compliance with new state laws or policies. Although the Utility may be allowed to recover some or all of the additional costs, there may be a substantial delay between when the Utility incurs the costs and when the Utility is authorized to collect revenues to recover such costs. Alternatively, the CPUC or the FERC may disallow costs that they determine were not reasonably or prudently incurred by the Utility.

The Utility also is required to incur costs to comply with legislative and regulatory requirements and initiatives, such as those relating to the development of a state-wide electric vehicle charging infrastructure, the deployment of distributed energy resources, implementation of demand response and customer energy efficiency programs, energy storage and renewable energy targets, underground gas storage, and the construction of the California high-speed rail project. The Utility's ability to recover costs, including its investments, associated with these and other legislative and regulatory initiatives will depend, in large part, on the final form of legislative or regulatory requirements, and the associated ratemaking mechanisms associated with these initiatives, including the timely adjustment of such mechanisms to reflect any lowered customer demand for the Utility's electricity and natural gas services.

PG&E Corporation's and the Utility's financial results depend upon the Utility's continuing ability to recover "pass-through" costs, including electricity and natural gas procurement costs, from customers in a timely manner. The CPUC may disallow procurement costs for a variety of reasons. In addition, the Utility's ability to recover these costs could be affected by the loss of Utility customers and decreased new customer growth, if the CPUC fails to adjust the Utility's rates to reflect such events.

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch" and prudent administration of power purchase agreements in compliance with its CPUC-approved long-term procurement plan. The CPUC could disallow procurement costs incurred by the Utility if the CPUC determines that the Utility did not comply with these principles or if the Utility did not comply with its procurement plan.

Further, the contractual prices for electricity under the Utility's current or future power purchase agreements could become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to adverse economic conditions or the loss of the Utility's customers to other retail providers. Despite the CPUC's current approval of the contracts, the CPUC could disallow contract costs in the future if it determines that the terms of such contracts, including price, do not meet the CPUC reasonableness standard.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by whether the CAISO wholesale electricity market continues to function effectively. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended which could result in excessive market prices. The CPUC could prohibit the Utility from passing through the higher costs of electricity to customers.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreasing bundled load that occurs through municipalization of the Utility's facilities, an increase in the number of CCAs that provide electricity to their residents, and an increase in the number of consumers who become direct access customers of alternative generation providers. (See "Competition in the Electricity Industry" in Item 1.) As the number of bundled customers (i.e., those customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase as the Utility would have a smaller customer base from which to recover certain procurement costs. Although the Utility is permitted to collect non-bypassable charges for above market generation-related costs incurred on behalf of former customers, the charges may not be sufficient for the Utility to fully recover these costs. In addition, the Utility's ability to collect non-bypassable charges has been, and may continue to be, challenged by certain customer groups. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer NEM, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pressure on remaining customers, who may incur significantly higher bills due to an increase in customers seeking alternative energy providers.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments. If the number of the Utility's customers decreases or grows at a slower rate than anticipated, the Utility's level of authorized capital investment could decline as well, leading to a slower growth in rate base and earnings. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, and cash flows.

Further, changes in commodity prices also may have an adverse effect on the Utility's ability to timely recover its operating costs and earn its authorized ROE. Although the Utility generally recovers its electricity and natural gas procurement costs from customers as "pass-through" costs, a significant and sustained rise in commodity prices could create overall rate pressures that make it more difficult for the Utility to recover its costs that are not categorized as "pass-through" costs. To relieve some of this upward rate pressure, the CPUC could authorize lower revenues than the Utility requested or disallow full cost recovery.

If the Utility is unable to recover a material portion of its procurement costs and/or if the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, the wide deployment of distributed generation, and the development of new electricity generation and energy storage technologies, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

Risks Related to Operations and Information Technology

The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks which, if they materialize, can materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. (See "Electric Utility Operations" and "Natural Gas Utility Operations" in Item 1. Business above.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives, and the CPUC approved retirement of Diablo Canyon by 2024 and 2025.

The Utility's ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond the Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines or other assets or group of assets, that can cause explosions, fires, public or workforce safety issues, large scale system disruption or other catastrophic events;

- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electrical black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees or the public, environmental damage, or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wildfire or natural gas explosion);
- inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;
- operator or other human error;
- a motor vehicle incident involving a Utility vehicle (or one operated on behalf of the Utility) resulting in serious injuries to or fatalities of the workforce or the public, property damage, or other consequences;
- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;
- construction performed by third parties that damages the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines;
- the release of hazardous or toxic substances into the air, water, or soil, including, for example, gas leaks from natural gas storage facilities; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and
- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war.

The occurrence of any of these events could interrupt fuel supplies; affect demand for electricity or natural gas; cause unplanned outages or reduce generating output; damage the Utility's assets or operations; damage the assets or operations of third parties on which the Utility relies; damage property owned by customers or others; and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, and to compensate third parties. Any of such incidents also could lead to significant claims against the Utility.

The adverse impact of the occurrence of any of these events may be exacerbated by the difficulty PG&E Corporation and the Utility may experience in making sufficient capital expenditure as a result of the Chapter 11 Cases. For the duration of the Chapter 11 Cases, the Utility's ability to finance capital expenditures and pay other ongoing expenses will primarily depend on the levels of its operating cash flows and availability under the DIP Credit Agreement. In the event that PG&E Corporation's and the Utility's capital needs increase materially due to unexpected events or transactions including but not limited to the events described above, additional financing outside of the DIP Facilities may be required, and there can be no assurance that PG&E Corporation and the Utility will be able to obtain such additional financing on favorable terms or at all, or that such additional financing will be approved by the Bankruptcy Court. In the event that PG&E Corporation and the Utility are unable to obtain such additional financing on favorable terms or at all, or are unable to obtain Bankruptcy Court approval of such additional financing, PG&E Corporation and the Utility may be unable to make necessary capital expenditures in connection with the occurrence of any of the above events. For more information on PG&E Corporation's and the Utility's material commitments for capital expenditures, see "Regulatory Matters" in Item 7. MD&A.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities, vegetation management, or the construction or demolition of facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions.

Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss 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's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events, or may not be available at a reasonable cost, or available at all.

The Utility has experienced increased costs and difficulties in obtaining insurance coverage for wildfires and other risks that could arise from the Utility's ordinary operations. PG&E Corporation, the Utility or its contractors and customers could continue to experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of the Utility's insurance coverage. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss that is not fully insured or cannot be recovered in customer rates could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

As a result of the potential application to investor-owned utilities of a strict liability standard under the doctrine of inverse condemnation, recent losses recorded by insurance companies, the risk of increased wildfires including as a result of climate change, the 2019 Kincadee fire, the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at a reasonable cost, or at all. In addition, the Utility is unable to predict whether it would be allowed to recover in rates the increased costs of insurance or the costs of any uninsured losses.

If the amount of insurance is insufficient or otherwise unavailable, or if the Utility is unable to obtain insurance at a reasonable cost or recover in rates the costs of any uninsured losses, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

The electric power and gas industries are undergoing significant changes driven by technological advancements and a decarbonized economy, which could materially affect the Utility's financial condition, results of operations, liquidity, and cash flows.

The electric power industry is undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policymakers. California's environmental policy objectives are accelerating the pace and scope of the industry change. For instance, SB 100, which was signed into law on September 10, 2018, increases from 50% to 60%, the percentage of California's electricity portfolio that must come from renewables by 2030. SB 100 establishes a further goal to have an electric grid that is entirely powered by clean energy by 2045. California utilities also are experiencing increasing deployment by customers and third parties of DERs, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and demand response technologies. These developments will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity, increase the grid's capacity, and interconnect DERs.

In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, EV infrastructure and state infrastructure modernization (e.g., rail and water projects).

To this end, the CPUC is conducting proceedings to: evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of DERs and, consider future grid modernization and grid reinforcement investments; evaluate if traditional grid investments can be deferred by DERs, and if feasible, what, if any, compensation to utilities would be appropriate for enabling those investments; and clarify the role of the electric distribution grid operator. The CPUC also authorized development of two new, five-year programs aimed at accelerating widespread electric vehicle adoption and combating climate change. The new programs will increase fast charging options for consumers as well as electric charging infrastructure for non-light-duty fleet vehicles.

In addition, in light of the state's commitment to clean energy and carbon neutral economy by 2045, California has recently proposed public policies that prohibit or restrict the use and consumption of natural gas, for example in buildings, that will have for effect to reduce the use of natural gas. Reducing natural gas use could lead to a reduction in the gas customer base and a diminished need for gas infrastructure and, as a result, could lead to certain gas assets no longer be "used and useful," potentially causing substantial investment value of gas assets to be stranded. (Under the CPUC rules, when an asset no longer meets the standard of "used and useful," the utility no longer recovers the costs from its customers or earns the associated rate of return.) However, while natural gas demand is projected to decline over time, the costs of operating a safe and reliable gas delivery system in California have been increasing, among other things, to cover the cost of long-term pipeline safety enhancements. Inability by the Utility to recover in rates its investments into the natural gas system while still ensuring gas system safety and reliability could materially affect the Utility's financial condition, results of operations, liquidity, and cash flows.

The industry changes, costs associated with complying with new regulatory developments and initiatives and with technological advancements, or the Utility's inability to successfully adapt to changes in the electric and gas industry, could materially affect the Utility's financial condition, results of operations, liquidity, and cash flows.

A cyber incident, cyber security breach, severe natural event or physical attack on the Utility's operational networks and information technology systems could have a material effect on its financial condition, results of operations, liquidity, and cash flows.

The Utility's electricity and natural gas systems rely on a complex, interconnected network of generation, transmission, distribution, control, and communication technologies, which can be damaged by natural events-such as severe weather or seismic events-and by malicious events, such as cyber and physical attacks. Private and public entities, such as the North American Electric Reliability Corporation, and U.S. Government Departments, including the Departments of Defense, Homeland Security and Energy, and the White House, have noted that cyber-attacks targeting utility systems are increasing in sophistication, magnitude, and frequency. The Utility's operational networks also may face new cyber security risks due to modernizing and interconnecting the existing infrastructure with new technologies and control systems. Any failure or decrease in the functionality of the Utility's operational networks could cause harm to the public or employees, significantly disrupt operations, negatively impact the Utility's ability to safely generate, transport, deliver and store energy and gas or otherwise operate in the most safe and efficient manner or at all, and damage the Utility's assets or operations or those of third parties.

The Utility also relies on complex information technology systems that allow it to create, collect, use, disclose, store and otherwise process sensitive information, including the Utility's financial information, customer energy usage and billing information, and personal information regarding customers, employees and their dependents, contractors, and other individuals. In addition, the Utility often relies on third-party vendors to host, maintain, modify, and update its systems, and to provide other services to the Utility or the Utility's customers. In addition, the Utility is increasingly being required to disclose large amounts of data (including customer energy usage and personal information regarding customers) to support changes to California's electricity market related to grid modernization and customer choice. These third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience security incidents or inadequate security measures. Any incidents or disruptions in the Utility's information technology systems could impact the Utility's ability to track or collect revenues and to maintain effective internal controls over financial reporting.

The Utility and its third-party vendors have been subject to, and will likely continue to be subject to, breaches and attempts to gain unauthorized access to the Utility's information technology systems or confidential data (including information about customers and employees), or to disrupt the Utility's operations. None of these breaches or attempts has individually or in the aggregate resulted in a security incident with a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent unauthorized access to its operational networks, information technology systems or data, or the disruption of its operations. Such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, penalties for violation of applicable privacy laws, investigations, and regulatory actions that could result in material fines and penalties, loss of customers and harm to PG&E Corporation's and the Utility's reputation, any of which 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 maintains cyber liability insurance that covers certain damages caused by cyber incidents. However, there is no guarantee that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.

The operation and decommissioning of the Utility's nuclear generation facilities expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the facilities cease operations before the licenses expire.

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses 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 Utility may be required under federal law to pay up to \$275 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States.

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon units by 2024 and 2025. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before their respective licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge 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, in order to retain highly skilled personnel necessary to safely operate Diablo Canyon during the remaining years of operations, the Utility will incur costs in connection with (i) an employee retention program to ensure adequate staffing levels at Diablo Canyon, which program has been approved by the CPUC, and (ii) an employee retraining and development program, to facilitate redeployment of a portion of Diablo Canyon personnel to the decommissioning project and elsewhere in the Utility. There can be no assurance that the Utility will be successful in retaining highly skilled personnel under its employee programs.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See “Regulatory Environment” in Item 1. Business above.) If the Utility were unable to recover these costs, PG&E Corporation’s and the Utility’s financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon’s two nuclear generation units before their respective licenses expire in 2024 and 2025. At December 31, 2019, the Utility’s unrecovered investment in Diablo Canyon was \$1.6 billion.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 3: Summary of Significant Accounting Policies - “Asset Retirement Obligations” of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility’s actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected.

For certain critical technologies, products and services, the Utility relies on a limited number of suppliers and, in some cases, sole suppliers. In the event these suppliers are unable to perform, the Utility could experience delays and disruptions in its operations while it transitions to alternative plans or suppliers.

The Utility relies on a limited number of sole source suppliers for certain of its technologies, products and services. Although the Utility has long-term agreements with such suppliers, if the suppliers are unable to deliver these technologies, products or services, the Utility could experience delays and disruptions while it implements alternative plans and makes arrangements with acceptable substitute suppliers. As a result, the Utility’s business, financial condition, and results of operations could be materially affected. As an example, the Utility relies on Westinghouse Electric Company LLC (acquired in 2018 by Brookfield Business Partners L.P.) for its nuclear fuel assemblies, and Silver Spring Networks, Inc. and Aclara Technologies LLC as suppliers of proprietary SmartMeter™ devices and software, and of managed services, utilized in its advanced metering system that collects electric and natural gas usage data from customers. If these suppliers encounter performance difficulties or are unable to supply these devices or maintain and update their software, or provide other services to maintain these systems, the Utility’s metering, billing, and electric network operations could be impacted and disrupted.

The Utility may be required to incur substantial costs in order to obtain or renew licenses and permits needed to operate the Utility’s business and the Utility may be subject to fines and penalties for failure to comply or obtain license renewal.

The Utility must comply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility’s hydroelectric generation facilities, and those issued by environmental and other federal, state and local governmental agencies. Many of the Utility’s capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizations, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility.

If a license or permit is not renewed for a particular facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs. Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Utility’s compliance costs. In particular, in connection with a license renewal for one or more of the Utility’s hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has not been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows. If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, licenses, ordinances, or other requirements, or if the Utility cannot recover the increase in associated compliance and other costs in a timely manner, PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected.

Risks Related to Environmental Factors

Severe weather conditions, extended drought and shifting climate patterns could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Extreme weather, prior extended drought and shifting climate patterns have intensified the challenges associated with wildfire management in California. The Utility's service territory encompasses some of the most densely forested areas in California and, as a consequence, is subject to higher risk from vegetation-related ignition events than other California IOUs. Further, environmental extremes, such as prior drought conditions followed by periods of wet weather, can drive additional vegetation growth (which can then fuel fires) and influence both the likelihood and severity of extraordinary wildfire events. In California, over the past five years, inconsistent and extreme precipitation, coupled with more hot days, have increased the wildfire risk and made wildfire outbreaks increasingly difficult to manage. In particular, the risk posed by wildfires has increased in the Utility's service area as a result of a prior extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases due to record rainfall following the drought, and strong wind events, among other environmental factors. Contributing factors other than environmental can include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk. For example, in 2017, there were nearly double the number of wildfires in California than the annual average, including five of the most devastating wildfires in California's history. On January 19, 2018, the CPUC approved a statewide fire-threat map that shows that approximately half of the Utility's service territory is facing "elevated" or "extreme" fire danger. Approximately 25,000 circuit miles of the Utility's nearly 81,000 distribution overhead circuit miles and approximately 5,500 miles of the nearly 18,000 transmission overhead circuit miles are in such high-fire threat areas, significantly more in total than other California IOUs.

Severe weather events and other natural disasters, including wildfires and other fires, storms, tornadoes, floods, heat waves, drought, earthquakes, tsunamis, rising sea levels, pandemics, solar events, electromagnetic events, or other natural disasters such as wildfires, could result in severe business disruptions, prolonged power outages, property damage, injuries or loss of life, significant decreases in revenues and earnings, and/or significant additional costs to PG&E Corporation and the Utility. Any such event could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Any of such events also could lead to significant claims against the Utility. Further, these events could result in regulatory penalties and disallowances, particularly if the Utility encounters difficulties in restoring power to its customers on a timely basis or if the related losses are found to be the result of the Utility's practices and/or the failure of electric and other equipment of the Utility.

Further, the Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns, rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. As a result, the Utility's hydroelectric generation could change and the Utility would need to consider managing or acquiring additional generation. If the Utility increases its reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including gas, generation, and electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, or compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial results.

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, and orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. (For more information, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. (See "Environmental Regulation" in Item 1. and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial results. Their financial results also can be materially affected by changes in estimated costs and by the extent to which actual remediation costs differ from recorded liabilities.

State climate policy requires reductions in greenhouse gases of 40% by 2030 and 80% by 2050. Various proposals for addressing these reductions have the potential to reduce natural gas usage and increase natural gas costs, which may impact the future of natural gas services. The future recovery of the increased costs associated with compliance is uncertain.

The CARB is the state's primary regulator for GHG emission reduction programs. Natural gas providers have been subject to compliance with CARB's Cap-and-Trade Program since 2015, and natural gas end-use customers have an increasing exposure to carbon costs under the Program through 2030 when the full cost will be reflected in customer bills. CARB's Scoping Plan also proposes various methods of reducing GHG emissions from natural gas. These include more aggressive energy efficiency programs to reduce natural gas end use, increased renewable portfolio standards generation in the electric sector reducing noncore gas load, and replacement of natural gas appliances with electric appliances, leading to further reduced demand. These natural gas load reductions may be partially offset by CARB's proposals to deploy natural gas to replace wood fuel in home heating and diesel in transportation applications. CARB also proposes a displacement of some conventional natural gas with above-market renewable natural gas. The combination of reduced load and increased costs could result in higher natural gas customer bills and a potential mandate to deliver renewable natural gas could lead to cost recovery risk. In addition, local city governments have passed ordinances restricting use of natural gas in new construction, and if other jurisdictions follow suit, this could affect future demand for the provision of natural gas.

Other Risk Factors

Poor investment performance or other factors could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefits for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. The performance of the debt and equity markets affects the value of plan assets and trust assets. A decline in the market value may increase the funding requirements for these plans and trusts. The cost of providing pension and other postretirement benefits is also affected by other factors, including interest rates used to measure the required minimum funding levels, the rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by the rates of return on trust assets, changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. (See Note 3: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in Item 8.) If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans or if actual nuclear decommissioning costs exceed the amount of nuclear decommissioning trust funds and the Utility is unable to recover the contributions or additional costs in rates, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.

The Utility's workforce is aging and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements with the unions or if tentative new agreements are not ratified by their members. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceedings and the Chapter 11 Cases. Any such occurrences could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility's business activities are concentrated in one region, as a result of which, its future performance may be affected by events and factors unique to California.

The Utility's business activities are concentrated in Northern California. As a result, the Utility's future performance may be affected by events and economic factors unique to California or by regional regulation or legislation, including, for example, the doctrine of inverse condemnation. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation and the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows" above.)

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, electric generation facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under "Electric Utility Operations" and "Natural Gas Utility Operations." The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11 million square feet of real property, including 9 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire in 2022.

The Utility currently owns approximately 158,000 acres of land, including approximately 128,000 acres of watershed lands. In 2002 the Utility agreed to implement its LCC to permanently preserve the six "beneficial public values" on all the watershed lands through conservation easements or equivalent protections, as well as to make approximately 40,000 acres of the watershed lands available for donation to qualified organizations. The six "beneficial public values" being preserved by the LCC include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Utility's goal is to implement all the transactions needed to implement the LCC by the end of 2022, subject to securing all required regulatory approvals.

ITEM 3. LEGAL PROCEEDINGS

In addition to the following proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see Item 7. MD&A, and Notes 2, 14, and 15 of the Notes to the Consolidated Financial Statements in Item 8.

U.S. District Court Matters and Probation

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

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

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

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

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

- prior to June 21, 2019, “re-inspect all of its electrical grid and remove or trim all trees that could fall onto its power lines, poles or equipment in high-wind conditions, . . . identify and fix all conductors that might swing together and arc due to slack and/or other circumstances under high-wind conditions[,] identify and fix damaged or weakened poles, transformers, fuses and other connectors [and] identify and fix any other condition anywhere in its grid similar to any condition that contributed to any previous wildfires,”
- “document the foregoing inspections and the work done and . . . rate each segment’s safety under various wind conditions,” and
- at all times from and after June 21, 2019, “supply electricity only through those parts of its electrical grid it has determined to be safe under the wind conditions then prevailing.”

The Utility was ordered to show cause by January 23, 2019 as to why the Utility’s conditions of probation should not be modified as proposed. The Utility’s response was submitted on January 23, 2019. The court requested that Cal Fire file a public statement, and invited the CPUC to comment, by January 25, 2019. On January 30, 2019, the court found that the Utility had violated a condition of its probation with respect to reporting requirements related to the 2017 Honey fire. The court issued an order stating that a sentencing hearing on the probation violation will be set at a later date. Also, on January 30, 2019, the court ordered the Utility to submit to the court on February 6, 2019 the 2019 Wildfire Mitigation Plan that the Utility was required to submit to the CPUC by February 6, 2019 in accordance with SB 901, and invited interested parties to comment on such plan by February 20, 2019. In addition, on February 14, 2019, the court ordered the Utility to provide additional information, including on its vegetation clearance requirements. The Utility submitted its response to the court on February 22, 2019.

On March 5, 2019, the court issued an order proposing to add new conditions of probation that would require the Utility, among other things, to:

- “fully comply with all applicable laws concerning vegetation management and clearance requirements;”
- “fully comply with the specific targets and metrics set forth in its wildfire mitigation plan, including with respect to enhanced vegetation management;”
- submit to “regular, unannounced inspections” by the Monitor “of PG&E’s vegetation management efforts and equipment inspection, enhancement, and repair efforts” in connection with a requirement that the Monitor “assess PG&E’s wildfire mitigation and wildfire safety work;”
- “maintain traceable, verifiable, accurate, and complete records of its vegetation management efforts” and report to the Monitor monthly on its vegetation management status and progress; and
- “ensure that sufficient resources, financial and personnel, including contractors and employees, are allocated to achieve the foregoing” and to forgo issuing “any dividends until [the Utility] is in compliance with all applicable vegetation management requirements as set forth above.”

The court ordered all parties to show cause by March 22, 2019, as to why the Utility's conditions of probation should not be modified as proposed. The responses of the Utility, the USAO, Cal Fire, the CPUC, and non-party victims were filed on March 22, 2019. At a hearing on April 2, 2019, the court indicated it would impose the new conditions of probation proposed on March 5, 2019, on the Utility, and on April 3, 2019, the Court issued an order imposing the new terms though amended the second condition to clarify that "[f]or purposes of this condition, the operative wildfire mitigation plan will be the plan ultimately approved by the CPUC."

Also, on April 2, 2019, the court directed the parties to submit briefing by April 16, 2019, regarding whether the court can extend the term of probation beyond five years in light of the violation that has been adjudicated and whether the Monitor reports should be made public. The responses of the Utility, the USAO, and the Monitor were filed on April 16, 2019. The Utility's response contended that the term of probation may not be extended beyond five years and the USAO's response contended that whether the term of probation could be extended beyond five years was an open legal issue.

The court held a sentencing hearing on the probation violation related to reporting requirements in connection with the 2017 Honey fire on May 7, 2019. After that hearing, the court imposed two additional conditions of probation by order dated May 14, 2019: (1) requiring that PG&E Corporation's Board of Directors, Chief Executive Officer, senior executives, the Monitor and U.S. Probation Officer visit the towns of Paradise and San Bruno "to gain a firsthand understanding of the harm inflicted on those communities;" and (2) requiring that a committee of PG&E Corporation's Board of Directors assume responsibility for tracking progress of the 2019 Wildfire Mitigation Plan and the additional terms of probation regarding wildfire safety, reporting in writing to the full Board at least quarterly. The court also stated that it was not going to rule at this time on whether the court has authority to extend probation and would leave that question "in abeyance." The court did not discuss whether the Monitor reports should be made public. Members of PG&E Corporation's Board of Directors and senior management attended site visits to the Town of Paradise on June 7, 2019 and the City of San Bruno on July 16, 2019, which were coordinated by the U.S. Probation Officer overseeing the Utility's probation. In addition, the Compliance and Public Policy Committee, a committee of PG&E Corporation's Board of Directors, will be responsible for tracking the Utility's progress against the Utility's wildfire mitigation plan, as approved by the CPUC, and compliance with the terms of the Utility's probation regarding wildfire safety.

On July 10, 2019, the court ordered the Utility to respond to a Wall Street Journal article titled "PG&E Knew for Years Its Lines Could Spark Wildfires, and Didn't Fix Them" on a paragraph-by-paragraph basis, stating the extent to which each paragraph in the article is accurate. The court also ordered the Utility to disclose all political contributions made by the Utility since January 1, 2017, and provide additional explanations regarding those contributions and dividends distributed prior to filing the Chapter 11 Cases. The Utility filed its response with the court on July 31, 2019. In the response, the Utility disagreed with the Wall Street Journal article's suggestion that the Utility knew of the specific maintenance conditions that caused the 2018 Camp fire and nonetheless deferred work that would have addressed those conditions.

On July 26, 2019, the Monitor submitted a letter to the court regarding its VM field inspections, which were designed to evaluate the Utility's compliance with aspects of its publicly-filed Wildfire Mitigation Plan's EVM. The Monitor's letter, which was filed on the public docket on August 14, 2019, provided its preliminary observations and preliminary findings, which included that (1) the Utility's contractors had missed trees that should have been identified and worked under the EVM program; and (2) the Utility's systems for recording, tracking and assigning EVM work were inconsistent and may have been contributing to the missed work. In its September 3, 2019 response to the Monitor's letter, the Utility detailed its plan to address the concerns raised by the Monitor. The Monitor's concerns and the Utility's response were discussed at a hearing on September 17, 2019.

During the September 17, 2019 hearing, the court asked the Utility to provide information about: (1) its preparation for high wind season; and (2) the number of fires 10 acres or greater allegedly caused by the Utility to date in 2019. The Utility responded on October 1, 2019 by describing its efforts to strengthen its programs and infrastructure to maximize safety and mitigate the potential wildfire risk during high wind season. The Utility also responded that as of September 17, 2019, the Utility's equipment may have contributed to nine ignitions in 2019 that resulted in fires 10 acres or greater. Two of these fires were potentially caused by vegetation and one was potentially caused by equipment. On October 2, 2019, the court asked the Utility for further information regarding the three fires potentially caused by vegetation and equipment. In its response, which was filed on October 9, 2019, the Utility provided information regarding certain fires, including but not limited to total acreage of the fire, ignition date, and potential causes.

On October 8, 2019, the court held a hearing related to the Utility's San Bruno community service.

On October 14, 2019, the court issued a request for information in connection with the PSPS event the Utility initiated on October 9, 2019 that shut off power to approximately 738,000 customers in 34 counties across Northern and Central California, asking the Utility to file a statement setting forth, among other information, “how many trees and limbs fell or blew onto the deenergized lines and how many of those would likely have caused arcing had the power been left on.” The Utility’s response was filed on October 30, 2019.

On November 4, 2019, the court issued a request for information in connection with PSPS events the Utility initiated in late October of 2019, asking the Utility to file a statement setting forth, among other information, the same type of information requested on October 14, 2019 in connection with the PSPS event initiated on October 9, 2019. The Utility filed its response on November 29, 2019.

On November 12, 2019, the court approved the request of the City of San Bruno to allow the Utility to satisfy the remainder of its community service requirements by making a \$3 million payment to the City of San Bruno, and on November 27, 2019, the court signed an order in connection therewith. As a result, on December 10, 2019, the court paid \$3 million to the City of San Bruno.

The Utility continued filing responses to the court’s additional requests in December 2019.

On December 20, 2019, the court ordered the Utility to state whether the Utility is in full compliance with two conditions of its probation: (1) the Utility must fully comply with all applicable laws concerning vegetation management and clearance requirements; and (2) the Utility must fully comply with the specific targets and metrics set forth in its wildfire mitigation plan. The Utility submitted its response to the court on January 15, 2020.

On January 16, 2020, the court issued an order to show cause noting that the Utility had admitted it was not in full compliance with the following conditions of probation: (1) fully complying with all applicable laws concerning vegetation management; and (2) fully complying with specific targets and metrics set forth in its wildfire mitigation plan. The court set a show cause hearing for February 19, 2020, to discuss why a further condition of probation should not be imposed requiring the Utility to hire sufficient crews to enable it to fully comply with the laws and its wildfire mitigation plan concerning vegetation management. The Utility submitted its response to the court on February 12, 2020.

On January 24, 2020, the court issued an additional order to show cause as to why, going forward, the Utility should not restrict all bonuses and other incentives for supervisors and above exclusively to achieving its wildfire mitigation plan and other safety goals. The Utility submitted its response to the court on February 12, 2020. A hearing in connection with this order is scheduled for February 19, 2020.

On February 4, 2020, the court issued an order directing the Utility to provide, by February 18, 2020, additional information in connection with the Utility’s prior responses dated November 29, 2019, December 19, 2019, and January 15, 2020, including regarding assets inspections and the condition of its electric assets.

The Utility expects to continue receiving additional orders from the court in the future.

Order Instituting an Investigation into PG&E Corporation’s and the Utility’s Safety Culture

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility’s and PG&E Corporation’s organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility’s record of operations, including its record of safety incidents. The SED engaged a consultant to assist in the SED’s investigation and the preparation of a report containing the SED’s assessment, and subsequently, to report on the implementation by the Utility of the consultant’s recommendations.

On May 8, 2017, the CPUC released the consultant’s report, accompanied by a scoping memo and ruling. The scoping memo established a second phase in the OII in which the CPUC evaluated the safety recommendations of the consultant. Phase two of the proceeding also considered all necessary measures, including, but not limited to, a potential reduction of the Utility’s return on equity. On November 17, 2017, the CPUC issued further a phase two scoping memo and procedural schedule. The scoping memo directed the Utility to file testimony addressing a number of issues including: adoption of the safety recommendations from the consultant, the Utility’s implementation process for the safety recommendations of the consultant, the Utility’s Board of Director’s actions and initiatives related to safety culture and the consultant’s recommendations, the Utility’s corrective action program, and the Utility’s response to certain specified safety incidents that occurred in 2013 through 2015.

The Utility's testimony was submitted to the CPUC on January 8, 2018 and stated that the Utility agrees with all the recommendations of the consultant and supports their adoption by the CPUC. Other parties' responsive testimony was submitted on February 16, 2018, followed by the Utility's rebuttal testimony on February 23, 2018.

On November 29, 2018, the CPUC approved a decision that directed the Utility to implement the recommendations set forth in the May 2017 consultant report no later than July 1, 2019, and to submit quarterly reports on the Utility's implementation status beginning in the fourth quarter of 2018.

On December 21, 2018, the CPUC issued another scoping memo and ruling expanding the proceeding and directing that the CPUC "will examine [PG&E's] current corporate governance, structure, and operations to determine if the utility is positioned to provide safe electrical and gas service, and will review alternatives to the current management and operational structures of providing electric and gas service in Northern California."

The CPUC alleged that the Utility has had "serious safety problems with both its gas and electric operations for many years" and that despite penalties and other remedial measures in connection with these problems, PG&E Corporation and the Utility have failed to develop "a comprehensive enterprise-wide approach to addressing safety." The scoping memo outlined a number of proposals to address the CPUC's concerns regarding PG&E Corporation's and the Utility's safety culture, including, but not limited to, (i) replacement of all or part of PG&E Corporation's and the Utility's existing boards of directors and corporate management, (ii) separating the Utility's gas and electric distribution and transmission businesses into separate companies, (iii) reorganizing the Utility into regional subsidiaries based on regional distinctions, (iv) reconstituting the Utility as a publicly owned utility or utilities, (v) providing for entities other than the Utility to provide generation services and (vi) conditioning the Utility's return on equity on safety performance. The scoping memo did not propose penalties and stated that this phase "is not a punitive phase." The Utility submitted its background filing to the CPUC on January 16, 2019 and opening comments were filed on February 13, 2019. The Utility and other parties filed reply comments on February 28, 2019. The CPUC held workshops on April 15, 2019 and April 26, 2019.

On June 13, 2019, the CPUC issued a decision that directed PG&E Corporation and the Utility to provide information about the safety experience and qualifications of each of the directors on their boards. PG&E Corporation and the Utility filed their response with the CPUC on July 3, 2019.

On June 18, 2019, the CPUC issued a ruling requesting comments from parties on four proposals that it stated may improve the safety culture of PG&E Corporation and the Utility. The four proposals are: separating the Utility into gas and electric utilities (including, as one possibility, sale of the gas assets to a third party); establishing periodic review of the Utility's certificate of convenience and necessity; modifying or eliminating PG&E Corporation's holding company structure; and linking the Utility's rate of return or return on equity to safety performance metrics.

Opening comments on the ruling were filed on July 19, 2019 and reply comments were filed on August 2, 2019.

PG&E Corporation and the Utility are unable to predict whether additional fines, penalties, or other regulatory actions may be taken, such as requiring the Utility to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or transfer ownership of the Utility's assets to municipalities or other public entities, or implement corporate governance changes.

Diablo Canyon Nuclear Power Plant

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Regional Water Quality Control Board. In January 2000, the Central Coast Regional Water Quality Control Board issued a proposed draft cease and desist order alleging that, although the permit's temperature limit had never been exceeded, the discharge was not protective of beneficial uses. This issue was resolved under a tentative global settlement addressing all aspects of the once-through cooling discharge that was initially approved in March 2003, but then later rejected by the Central Coast Regional Water Quality Control Board. Subsequently, in 2010 the California Water Board adopted a policy on once-through cooling that established specific compliance requirements. For Diablo Canyon, the policy set a compliance date of December 31, 2024, required an evaluation of the feasibility and cost of alternative technologies, and allowed for alternative compliance requirements. However, with the January 11, 2018 CPUC approval of Diablo Canyon's retirement at the expiration of its existing NRC licenses, alternative compliance measures are no longer necessary. The policy still requires annual interim mitigation payments based on actual cooling water flow volume, which the Utility will continue to pay until operations cease in 2025.

The Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility and the Central Coast Regional Water Quality Control Board regarding the thermal component of the plant's once-through cooling discharge. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material effect on the Utility's financial condition, results of operations, liquidity, and cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The following individuals serve as executive officers of PG&E Corporation, as of February 18, 2020. Except as otherwise noted, all positions have been held at PG&E Corporation.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|--------------------|-----|---|--------------------------------------|
| William D. Johnson | 66 | Chief Executive Officer and President | May 2, 2019 to present |
| | | President and Chief Executive Officer, Tennessee Valley Authority | 2012 to April 2019 |
| John R. Simon | 55 | Executive Vice President, Law, Strategy and Policy | June 3, 2019 to present |
| | | Executive Vice President | May 2, 2019 to June 2, 2019 |
| | | Interim Chief Executive Officer | January 14, 2019 to May 1, 2019 |
| | | Executive Vice President and General Counsel | March 1, 2017 to January 13, 2019 |
| | | Executive Vice President, Corporate Services and Human Resources | August 18, 2015 to February 28, 2017 |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | April 16, 2007 to August 17, 2015 |
| Jason P. Wells | 42 | Executive Vice President and Chief Financial Officer | May 16, 2019 to present |
| | | Senior Vice President and Chief Financial Officer, PG&E Corporation | January 1, 2016 to May 15, 2019 |
| | | Vice President, Business Finance, Pacific Gas and Electric Company | August 1, 2013 to December 31, 2015 |
| Andrew M. Vesey | 64 | Chief Executive Officer and President, Pacific Gas and Electric Company | August 19, 2019 to present |
| | | Advisor, AGL Energy Limited | September 2018 to December 2018 |
| | | Managing Director and Chief Executive Officer, AGL Energy Limited | February 2015 to September 2018 |

| | | | |
|-----------------|----|--|--------------------------------------|
| Janet C. Loduca | 52 | Senior Vice President and General Counsel, PG&E Corporation and Pacific Gas and Electric Company | May 2, 2019 to present |
| | | Senior Vice President and Interim General Counsel, PG&E Corporation and Pacific Gas and Electric Company | January 14, 2019 to May 1, 2019 |
| | | Senior Vice President and Deputy General Counsel, Pacific Gas and Electric Company | December 1, 2018 to January 13, 2019 |
| | | Vice President and Deputy General Counsel, Pacific Gas and Electric Company | March 1, 2017 to November 30, 2018 |
| | | Vice President, Investor Relations | January 1, 2015 to February 28, 2017 |

The following individuals serve as executive officers of the Utility as of February 18, 2020. Except as otherwise noted, all positions have been held at the Utility.

| <u>Name</u> | <u>Age</u> | <u>Positions Held Over Last Five Years</u> | <u>Time in Position</u> |
|------------------|------------|--|--------------------------------------|
| Andrew M. Vesey | 64 | Chief Executive Officer and President | August 19, 2019 to present |
| | | Advisor, AGL Energy Limited | September 2018 to December 2018 |
| | | Managing Director and Chief Executive Officer, AGL Energy Limited | February 2015 to September 2018 |
| Michael A. Lewis | 57 | Senior Vice President, Electric Operations | January 8, 2019 to present |
| | | Vice President, Electric Distribution Operations | August 1, 2018 to January 7, 2019 |
| | | Senior Vice President and Chief Distribution Officer, Duke Energy | September 2016 to August 2018 |
| | | Senior Vice President and Chief Transmission Officer, Duke Energy | January 2015 to August 2016 |
| Janet C. Loduca | 52 | Senior Vice President and General Counsel, PG&E Corporation and Pacific Gas and Electric Company | May 2, 2019 to present |
| | | Senior Vice President and Interim General Counsel, PG&E Corporation and Pacific Gas and Electric Company | January 14, 2019 to May 1, 2019 |
| | | Senior Vice President and Deputy General Counsel | December 1, 2018 to January 13, 2019 |
| | | Vice President and Deputy General Counsel | March 1, 2017 to November 30, 2018 |
| | | Vice President, Investor Relations, PG&E Corporation | January 1, 2015 to February 28, 2017 |
| James M. Welsch | 64 | Senior Vice President, Generation and Chief Nuclear Officer | August 10, 2019 to present |
| | | Senior Vice President and Chief Nuclear Officer | May 16, 2019 to August 9, 2019 |
| | | Vice President, Nuclear Generation and Chief Nuclear Officer | November 1, 2017 to May 15, 2019 |
| | | Vice President, Nuclear Generation | November 4, 2016 to October 31, 2017 |
| | | Site Vice President, Diablo Canyon Power Plant | January 1, 2015 to November 3, 2016 |

| | | | |
|-------------------|----|--|--------------------------------|
| David S. Thomason | 44 | Vice President, Chief Financial Officer, and Controller, Pacific Gas and Electric Company | June 1, 2016 to present |
| | | Vice President and Controller, PG&E Corporation | June 1, 2016 to present |
| | | Senior Director, Financial Forecasting and Analysis | March 2, 2015 to May 31, 2016 |
| | | Senior Director, Corporate Accounting | March 2, 2014 to March 1, 2015 |

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 13, 2020, there were 47,907 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and is traded under the symbol "PCG". Shares of common stock of the Utility are wholly owned by PG&E Corporation. 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. (See "Liquidity and Financial Resources - Dividends" in Item 7. MD&A and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and in Note 6 of the Notes to the Consolidated Financial Statements in Item 8.)

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2019, PG&E Corporation did not make any equity contributions to the Utility. Also, PG&E Corporation did not make any sales of unregistered equity securities during 2019 in reliance on an exemption from registration under the Securities Act of 1933, as amended.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2019, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. Also, during the quarter ended December 31, 2019, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. SELECTED FINANCIAL DATA**(in millions, except per share amounts)**

| | <u>2019</u> | <u>2018</u> | <u>2017</u> | <u>2016</u> | <u>2015</u> |
|--|-------------|-------------|-------------|-------------|-------------|
| PG&E Corporation | | | | | |
| For the Year | | | | | |
| Operating revenues | \$ 17,129 | \$ 16,759 | \$ 17,135 | \$ 17,666 | \$ 16,833 |
| Operating income (loss) | (10,094) | (9,700) | 2,905 | 2,080 | 1,508 |
| Net income (loss) | (7,642) | (6,837) | 1,660 | 1,407 | 888 |
| Net earnings (loss) per common share, basic ⁽¹⁾ | (14.50) | (13.25) | 3.21 | 2.79 | 1.81 |
| Net earnings (loss) per common share, diluted | (14.50) | (13.25) | 3.21 | 2.78 | 1.79 |
| Dividends declared per common share ⁽²⁾ | — | — | 1.55 | 1.93 | 1.82 |
| At Year-End | | | | | |
| Common stock price per share | \$ 10.87 | \$ 23.75 | \$ 44.83 | \$ 60.77 | \$ 53.19 |
| Total assets ⁽³⁾ | 85,196 | 76,995 | 68,012 | 68,598 | 63,234 |
| Long-term debt (excluding current portion) | — | — | 17,753 | 16,220 | 15,925 |
| Operating lease obligations (excluding current portion) | 1,730 | — | — | — | — |
| Financing lease obligations (excluding current portion) ⁽³⁾ | 7 | 9 | 18 | 31 | 49 |
| Financing debt subject to compromise | 23,116 | — | — | — | — |
| Pacific Gas and Electric Company | | | | | |
| For the Year | | | | | |
| Operating revenues | \$ 17,129 | \$ 16,760 | \$ 17,138 | \$ 17,667 | \$ 16,833 |
| Operating income (loss) | (10,118) | (9,699) | 2,846 | 2,081 | 1,511 |
| Income (loss) available for common stock | (7,636) | (6,832) | 1,677 | 1,388 | 848 |
| At Year-End | | | | | |
| Total assets | 84,614 | 76,471 | 67,884 | 68,374 | 63,037 |
| Long-term debt (excluding current portion) | — | — | 17,403 | 15,872 | 15,577 |
| Operating lease obligations (excluding current portion) | 1,726 | — | — | — | — |
| Financing lease obligations (excluding current portion) ⁽³⁾ | 7 | 9 | 18 | 31 | 49 |
| Financing debt subject to compromise | 22,450 | — | — | — | — |

⁽¹⁾ See “Overview – Summary of Changes in Net Income and Earnings per Share” in Item 7. MD&A.

⁽²⁾ Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in “Liquidity and Financial Resources – Dividends” in Item 7. MD&A and in PG&E Corporation’s Consolidated Statements of Equity, the Utility’s Consolidated Statements of Shareholders’ Equity, and Note 6 of the Notes to the Consolidated Financial Statements in Item 8.

⁽³⁾ The financing lease obligations amounts are included in noncurrent liabilities -- other in PG&E’s Corporation’s and the Utility’s Consolidated Balance Sheets.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**OVERVIEW**

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's base revenue requirements are set by the CPUC in its GRC and GT&S rate case based on forecast costs. Differences between forecast costs and actual costs can occur for numerous reasons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. Generally, differences between actual costs and forecast costs affect the Utility's ability to earn its authorized return (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations below). The Utility's base transmission revenue requirements are recovered through a formula rate approved by FERC that trues up forecast and actual costs. However, for certain operating costs, such as costs associated with pension benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). The Utility also collects revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, such as the costs to procure electricity or natural gas for its customers. Therefore, although these costs can fluctuate, they generally do not impact net income (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). See "Ratemaking Mechanisms" in Item 1. Business for further discussion.

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

Chapter 11 Proceedings

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. PG&E Corporation's and the Utility's Chapter 11 Cases are being jointly administered under the caption In re: PG&E Corporation and Pacific Gas and Electric Company, Case No. 19-30088 (DM). For additional information regarding the Chapter 11 Cases, refer to the website maintained by Prime Clerk, LLC, PG&E Corporation's and the Utility's claims and noticing agent, at <http://restructuring.primeclerk.com/pge>. The contents of this website are not incorporated into this document.

For more information about the Chapter 11 Cases, see "Item 1A. Risk Factors – Risks Related to Chapter 11 Proceedings and Liquidity" and Notes 2 and 5 of the Notes to the Consolidated Financial Statements in Item 8 of this 2019 Form 10-K.

Going Concern

The accompanying Consolidated Financial Statements to this Annual Report on Form 10-K 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, 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. As a result of these challenges, such realization of assets and satisfaction of liabilities are subject to uncertainty. For more information about the 2018 Camp fire and 2017 Northern California wildfires, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Management has concluded that uncertainty regarding these matters raises substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns, and their independent registered public accountants have included an explanatory paragraph in their auditors' reports which states certain conditions exist which raise substantial doubt about PG&E Corporation's and the Utility's ability to continue as going concerns in relation to the foregoing. The Consolidated Financial Statements do not include any adjustments that might result from the outcome of this uncertainty. For more information about these matters, see Notes 1 and 2 of the Notes to the Consolidated Financial Statements and "Report of Independent Registered Public Accounting Firm" in Item 8.

Summary of Changes in Net Income and Earnings per Share

PG&E Corporation's net loss attributable to common shareholders were \$7.7 billion in 2019, compared to \$6.9 billion in 2018. PG&E Corporation recognized charges of \$11.4 billion for claims in connection with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire for the year ended December 31, 2019, compared to charges of \$14.0 billion, net of probable insurance recoveries of \$2.2 billion, associated with third-party claims and legal and other costs related to the 2018 Camp fire and the 2017 Northern California wildfires during the year ended December 31, 2018.

Key Factors Affecting Financial Results

PG&E Corporation and the Utility believe that their financial condition, results of operations, liquidity, and cash flows may be materially affected by the following factors:

- *The Outcome of the Chapter 11 Cases.* For the duration of the Chapter 11 Cases, PG&E Corporation's and the Utility's business is subject to the risks and uncertainties of bankruptcy. For example, the Chapter 11 Cases could adversely affect the Utility's relationships with suppliers and employees which, in turn, could adversely affect the value of the business and assets of PG&E Corporation and the Utility. PG&E Corporation and the Utility also have incurred and expect to continue to incur increased legal and other professional costs associated with the Chapter 11 Cases and the reorganization. At this time, it is not possible to predict with certainty the effect of the Chapter 11 Cases on their business or various creditors, or whether or when PG&E Corporation and the Utility will emerge from bankruptcy. PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity and cash flows depend upon confirming, and successfully implementing, on a timely basis, a plan of reorganization. Although PG&E Corporation and the Utility have entered into settlement agreements to resolve the claims of the major classes of claimholders, including Utility debtholders, individual wildfire victims, holders of subrogated insurance claims and certain public entities, non-consenting claimholders may still be able to challenge and otherwise impede the Proposed Plan. These settlement agreements could be terminated under various circumstances, some of which are beyond PG&E Corporation's and the Utility's control. In addition, PG&E Corporation's and the Utility's ability to emerge from Chapter 11 is dependent on their ability to satisfy the conditions set forth in AB 1054, as determined by the CPUC. PG&E Corporation and the Utility believe the Proposed Plan meets the requirements of AB 1054 by, among other things, satisfying wildfire claims through settlements consistent with the terms of AB 1054, by keeping rates neutral, on average, for the Utility's customers, and by providing for the assumption of all power-purchase agreements, community-choice aggregation servicing agreements, and collective bargaining agreements. Finally, in order to emerge from Chapter 11, PG&E Corporation and the Utility must finance the Proposed Plan. There are numerous uncertainties related to such financings, including the ability to successfully raise equity or debt in the public or private markets, the ability to satisfy the terms and conditions set forth in the debt and equity commitment letters and the Noteholder RSA, the ability to collect insurance proceeds and the amount of additional capital that could be obtain to finance the Proposed Plan, including through securitization.
- *The Utility's Ability to Fund Ongoing Operations and Other Capital Needs.* In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement, which was approved on a final basis on March 27, 2019. For the duration of the Chapter 11 Cases, PG&E Corporation and the Utility expect that the DIP Credit Agreement, together with cash on hand and cash flow from operations, will be the Utility's primary source of capital to fund ongoing operations and other capital needs and that they will have limited, if any, access to additional financing. In the event that cash on hand, cash flow from operations, and availability under the DIP Credit Agreement are not sufficient to meet liquidity needs, PG&E Corporation and the Utility may be required to seek additional financing, and can provide no assurance that additional financing would be available or, if available, offered on acceptable terms. The amount of any such additional financing could be limited by negative covenants in the DIP Credit Agreement, which include restrictions on PG&E Corporation's and the Utility's ability to, among other things, incur additional indebtedness and create liens on assets.
- *The Impact of the 2018 Camp Fire and the 2017 Northern California Wildfires.* PG&E Corporation and the Utility face several uncertainties in connection with the 2018 Camp fire and 2017 Northern California wildfires, related to:
 - the amount of possible loss related to third-party claims (as of December 31, 2019, the Utility's best estimate of probable loss in connection with the 2018 Camp fire, 2017 Northern California wildfires and 2015 Butte fire was \$25.5 billion), which amount is subject to change based on a number of factors, including whether existing settlements are upheld, 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, and the ongoing criminal investigation with respect to the 2018 Camp fire;
 - whether, in light of the CPUC July 8, 2019 final decision in the CHT OIR that excludes companies in Chapter 11 from accessing the CHT, the Utility will be able to obtain a substantial recovery of costs related to the 2017 Northern California wildfires;
 - the impact of investigations, including criminal, regulatory, and SEC investigations;

- fines or penalties, which could be material, if any regulatory or law enforcement agency were to bring an enforcement action, including a criminal proceeding, and determine that the Utility had failed to comply with applicable laws and regulations;
- the amount of punitive damages, fines and penalties, or damages in respect of future claims, which could be material;
- the applicability of the doctrine of inverse condemnation in the 2018 Camp fire and 2017 Northern California wildfires litigation;
- the applicability of other theories of liability, including negligence, related to the 2018 Camp fire and 2017 Northern California wildfire claims;
- the recoverability of the above-mentioned costs, even if a court decision imposes liability under the doctrine of inverse condemnation;
- the ability of PG&E Corporation and the Utility to finance costs, expenses and other possible losses in respect of claims related to the 2018 Camp fire and the 2017 Northern California wildfires, through securitization mechanisms or otherwise; and
- the amount and recoverability of clean-up and repair costs (the Utility incurred costs of \$1.13 billion for clean-up and repair of the Utility's facilities through December 31, 2019).

(See Notes 4 and 14 of the Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors in Part I.)

- *The Impact of the 2019 Kincade Fire.* Regardless of whether the Utility is determined to have caused the 2019 Kincade fire, the 2019 Kincade fire could have numerous adverse consequences to PG&E Corporation and the Utility, including, among others:
 - PG&E Corporation's and the Utility's ability to consummate the Proposed Plan by June 30, 2020 (or at all) could be impaired, and PG&E Corporation and the Utility may not be able to amend the Proposed Plan, or develop another alternative to the Proposed Plan, that could be confirmed by June 30, 2020 (or at all);
 - depending on the number and type of structures damaged or destroyed by the 2019 Kincade fire or the amount of post-petition claims against PG&E Corporation or the Utility as a result of the 2019 Kincade fire, PG&E Corporation and the Utility may not be able to satisfy, or obtain a waiver of, the conditions precedent to the commitments under the Backstop Commitment Letters or the Debt Commitment Letters, or the Backstop Parties or the Commitment Parties, respectively, may have the right to terminate such commitments, which would jeopardize PG&E Corporation's and the Utility's ability to finance the Proposed Plan;
 - PG&E Corporation and the Utility may not be able to obtain alternative financing to the transactions contemplated by the Backstop Commitment Letters and the Debt Commitment Letters, and may not be able to obtain financing for an alternative plan that may be proposed by PG&E Corporation and the Utility after the impact of the 2019 Kincade fire is better known;
 - 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;
 - the 2019 Kincade fire may have adverse consequences on the Utility's probation proceeding, the Utility's proceedings with the CPUC and FERC (including the Safety Culture OII and the Chapter 11 Proceedings OII), the criminal investigation into the 2018 Camp fire and future regulatory proceedings, including future applications for the safety certification required by AB 1054;
 - PG&E Corporation and the Utility may experience even greater difficulty in securing adequate insurance coverage for wildfire risks; and

- PG&E Corporation and the Utility expect to suffer additional reputational harm and face an even more challenging operating, political, and regulatory environment.
- *The Uncertainties in Connection with Any Future Wildfires, Wildfire Insurance, and AB 1054.* While PG&E Corporation and the Utility cannot predict the occurrence, timing or extent of damages in connection with future wildfires, factors such as environmental conditions (including weather and vegetation conditions) and the efficacy of wildfire risk mitigation initiatives are expected to influence the frequency and severity of future wildfires. Although the financial impact of future wildfires could be mitigated through insurance, the Utility may not be able to obtain sufficient wildfire insurance coverage at a reasonable cost, or at all, and any such coverage may include limitations that could result in substantial uninsured losses depending on the amount and type of damages resulting from covered events. In addition, the policy reforms contemplated by AB 1054 are likely to affect the financial impact of future wildfires on PG&E Corporation and the Utility should any such wildfires occur. The Wildfire Fund would be available to the Utility to pay eligible claims for liabilities arising from future wildfires and would serve as an alternative to traditional insurance products, provided that the Utility satisfies the numerous conditions to the Utility's participation in the Wildfire Fund set forth in AB 1054 and that the Wildfire Fund has sufficient remaining funds.

However, the impact of AB 1054 on PG&E Corporation and the Utility is subject to numerous uncertainties, including the Utility's eligibility to access relief under the Wildfire Fund (which is dependent on, among other things, the Chapter 11 Cases being resolved by June 30, 2020 pursuant to a plan or similar document not subject to a stay and the Utility making its initial contribution thereto), the Utility's ability to demonstrate to the CPUC that wildfire-related costs paid from the Wildfire Fund were just and reasonable, and whether the benefits of participating in the Wildfire Fund ultimately outweigh its substantial costs. The Utility may not be able to finance its required contributions to the Wildfire Fund, which consist of an initial contribution of approximately \$4.8 billion and annual contributions of approximately \$193 million. Finally, even if the Utility satisfies the eligibility and other requirements set forth in AB 1054, for eligible claims against the Utility arising between July 12, 2019 and the Utility's emergence from Chapter 11, the availability of the Wildfire Fund to pay such claims will be capped at 40% of the amount of such claims.

- *The AB 1054 Deadline of June 30, 2020.* In the event that PG&E Corporation and the Utility are unable to confirm a plan of reorganization by June 30, 2020, the Utility will not be eligible to participate in the Wildfire Fund established under AB 1054. In that scenario, the Utility (i) would be unable to seek payment from the Wildfire Fund for liabilities arising from wildfires occurring after the July 12, 2019 effective date of AB 1054 (which in the case of pre-emergence wildfires, such as the 2019 Kincadee fire, would be limited to 40% of such liabilities), (ii) would not receive the benefit of the 20% disallowance cap contemplated by AB 1054, (iii) would not be required to make any contributions to the Wildfire Fund, (iv) in applications for cost recovery for wildfires occurring after July 12, 2019, would nevertheless be subject to review under the "just and reasonable" standard set forth in section 451.1 of the Public Utilities Code (i.e., the standard as modified by AB 1054) and (v) may still be eligible to obtain the annual safety certifications contemplated by section 8389 of the Public Utilities Code (which has implications for the burden of proof in a proceeding for cost recovery under section 451.1 of the Public Utilities Code).

- The Uncertainties Regarding the Impact of Recent and Future Public Safety Power Shutoffs.* The Utility's wildfire risk mitigation initiatives involve substantial and ongoing expenditures and could involve other costs. The extent to which the Utility will be able to recover these expenditures and potential other costs through rates is uncertain. The PSPS program, one of the Utility's wildfire risk mitigation initiatives outlined in the 2019 Wildfire Mitigation Plan, has been the subject of significant scrutiny and criticism by various stakeholders, including the California Governor, the CPUC and the court overseeing the Utility's probation. On November 12, 2019, the CPUC issued an order to show cause why the Utility should not be sanctioned for alleged violations of law related to its communications with customers, coordination with local governments, and communications with critical facilities and public safety partners during the PSPS events in late 2019. On November 13, 2019, the CPUC instituted an OII to examine 2019 PSPS events carried out by California's investor-owned utilities and to consider enforcement actions. PG&E Corporation and the Utility cannot predict the timing and outcome of the OII and order to show cause, and PG&E Corporation and the Utility could be subject to additional investigations, regulatory proceedings or other enforcement actions as well as to litigation and claims by customers, which could result in fines, penalties, customer rebates or other payments. On October 29, 2019, PG&E Corporation and the Utility announced that they would issue credits to customers with respect to the October 9, 2019 PSPS event. PG&E Corporation and the Utility recorded a charge of \$86 million reflecting a one-time bill credit for customers impacted by the October 9, 2019 PSPS event in the fourth quarter of 2019. As of the date of this filing, PG&E Corporation and the Utility do not expect to issue any similar customer credits in connection with any other PSPS events (whether past events or in the future). If PG&E Corporation or the Utility were to issue any credits, rebates or other payments in connection with any other PSPS events (whether past events or in the future), the aggregate amount of any such credits, rebates, or other payments could be substantial and 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 proposals of SB 378, which would impose penalties and other requirements on electric utility companies relating to PSPS events, 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 to other requirements, SB 378 would impose on an electric utility company a civil penalty of at least \$250,000 per 50,000 affected customers for every hour that a PSPS event is in place, would require the CPUC to establish a procedure for customers, local governments and others to recover costs accrued during a PSPS event from the electric utility company, which cost recovery would be borne by shareholders, and would prohibit an electric utility company from billing customers for any nonfixed costs during a PSPS event. Further, the proposals of AB 1941 could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. AB 1941 proposes to suspend RPS requirements, determine the savings to electric utility companies from the suspension and direct those savings towards system hardening to mitigate wildfire risks and PSPS impacts, and would prohibit salary increases or bonuses to executive officers during the suspension of RPS requirements. In addition, the PSPS program has had an adverse impact on PG&E Corporation's and the Utility's reputation with customers, regulators and policymakers and future PSPS events may increase these negative perceptions. In addition to the 2019 PSPS events, the Utility expects that PSPS events will be necessary in 2020 and future years.
- The Costs of Other Wildfire Mitigation Efforts.* In response to the wildfire threat facing California, PG&E Corporation and the Utility have taken aggressive steps to mitigate the threat of catastrophic wildfires, the spread of wildfires should they occur and the impact of PSPS events. PG&E Corporation and the Utility incurred approximately \$2.6 billion in connection with the 2019 WMP, and expect to incur approximately \$2.6 billion in 2020 in connection with its 2020-2022 WMP. Although the Utility may seek cost recovery for certain of these expenses and capital expenditures, the Utility has agreed not to seek rate recovery of certain wildfire-related expenses and capital expenditures in future applications in the amount of \$1.625 billion.

While PG&E Corporation and the Utility are committed to taking aggressive wildfire mitigation actions, if additional requirements are imposed that go beyond current expectations, such requirements could have a substantial impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. The Court in the Utility's probation proceeding in connection with the Utility's federal criminal proceeding has imposed numerous obligations on the Utility related to its business and operations, including full compliance with all applicable laws concerning vegetation management and clearance requirements, submission to regular, unannounced inspections by the Monitor of the Utility's vegetation management efforts and equipment inspection, enhancement and repair efforts and the maintenance of traceable, verifiable, accurate and complete records of the Utility's vegetation management efforts and monthly reports to the Monitor on the status and progress of vegetation management efforts. On January 16, 2020, the Court proposed to require the Utility to materially expand its vegetation management program, including through the hiring of additional employees. PG&E Corporation and the Utility also face uncertainties in connection with the amount and recoverability of enhanced and accelerated inspection costs of the Utility's electric transmission and distribution assets (the Utility incurred costs of \$773 million for enhanced and accelerated inspection and repair costs for the year ended December 31, 2019). (See "Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

- *The Outcome of Other Enforcement, Litigation, and Regulatory Matters, and Other Government Proposals.* The Utility's financial results may continue to be impacted by the outcome of other current and future enforcement, litigation (to the extent not stayed as a result of the Chapter 11 Cases), and regulatory matters, including those described above as well as the outcome of the locate and mark OII, the outcome of the safety culture OII, the sentencing terms of the Utility's January 27, 2017 federal criminal conviction, including the oversight of the Utility's probation and the potential recommendations by the Monitor, and potential penalties in connection with the Utility's safety and other self-reports. (See Note 15 of the Notes to the Consolidated Financial Statements in Item 8.) In addition, the Utility's business profile and financial results could be impacted by the outcome of recent calls for municipalization of part or all of the Utility's businesses, offers by municipalities and other public entities to acquire the electric assets of the Utility within their respective jurisdictions and calls for state intervention, including the possibility of a state takeover of the Utility. PG&E Corporation and the Utility cannot predict the nature, occurrence, timing or extent of any such scenario, and there can be no assurance that any such scenario would not involve significant ownership or management changes to PG&E Corporation or the Utility, including by the state of California.
- *The Timing and Outcome of Ratemaking Proceedings.* The Utility's financial results may be impacted by the timing and outcome of its 2020 GRC, FERC TO18, TO19, and TO20 rate cases, and its ability to timely recover costs not currently in rates, including costs already incurred and future costs tracked in its CEMA, WEMA, FHPMA, WMPMA, and FRMMA that are incurred in connection with the Utility's 2019 Wildfire Mitigation Plan, the amount of which is approximately \$2.6 billion. The outcome of regulatory proceedings can be affected by many factors, including intervening parties' testimonies, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors. (See Notes 4 and 15 of the Notes to the Consolidated Financial Statements in Item 8 and "Regulatory Matters" below.)
- *The Utility's Compliance with the CPUC Capital Structure.* The CPUC's capital structure decisions require the Utility to maintain a 52% equity ratio on average over the period that the authorized capital structure is in place, and to file an application for a waiver to the capital structure condition if an adverse financial event reduces its equity ratio by 1% or more. 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 CPUC's decisions state that the Utility shall not be considered in violation of these conditions during the period the waiver application is pending resolution. The Utility is unable to predict the timing and outcome of its waiver application. (See "Regulatory Matters" below.)

For more information about the risks that could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in this 2019 Form 10-K. In addition, this 2019 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are unable to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2019, 2018, and 2017. See "Key Factors Affecting Financial Results" above for further discussion about factors that could affect future results of operations.

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders:

| (in millions) | 2019 | 2018 | 2017 |
|--------------------|------------|------------|----------|
| Consolidated Total | \$ (7,656) | \$ (6,851) | \$ 1,646 |
| PG&E Corporation | (20) | (19) | (31) |
| Utility | \$ (7,636) | \$ (6,832) | \$ 1,677 |

PG&E Corporation's net income (loss) increased in 2019, as compared to 2018, primarily due to the impacts of the Chapter 11 Cases in 2019, with no corresponding activities in 2018.

PG&E Corporation's net income (loss) decreased in 2018, as compared to 2017, primarily due to the impact of the San Bruno Derivative Litigation in 2017 with no corresponding activity in 2018, partially offset by additional income taxes in 2017.

Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2019, 2018, and 2017. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as energy procurement costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

| (in millions) | 2019 | | | 2018 | | | 2017 | | |
|--|------------------------|------------------------------|-------------------|------------------------|------------------------------|-------------------|------------------------|------------------------------|-----------------|
| | Revenues and Costs: | | | Revenues and Costs: | | | Revenues and Costs: | | |
| | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
| Electric operating revenues | \$ 8,634 | \$ 4,106 | \$ 12,740 | \$ 7,859 | \$ 4,854 | \$ 12,713 | \$ 7,897 | \$ 5,230 | \$ 13,127 |
| Natural gas operating revenues | 3,259 | 1,130 | 4,389 | 3,046 | 1,001 | 4,047 | 2,969 | 1,042 | 4,011 |
| Total operating revenues | 11,893 | 5,236 | 17,129 | 10,905 | 5,855 | 16,760 | 10,866 | 6,272 | 17,138 |
| Cost of electricity | — | 3,095 | 3,095 | — | 3,828 | 3,828 | — | 4,309 | 4,309 |
| Cost of natural gas | — | 734 | 734 | — | 671 | 671 | — | 746 | 746 |
| Operating and maintenance | 7,167 | 1,583 | 8,750 | 5,475 | 1,678 | 7,153 | 5,112 | 1,271 | 6,383 |
| Wildfire-related claims, net of insurance recoveries | 11,435 | — | 11,435 | 11,771 | — | 11,771 | — | — | — |
| Depreciation, amortization, and decommissioning | 3,233 | — | 3,233 | 3,036 | — | 3,036 | 2,854 | — | 2,854 |
| Total operating expenses | 21,835 | 5,412 | 27,247 | 20,282 | 6,177 | 26,459 | 7,966 | 6,326 | 14,292 |
| Operating income (loss) | (9,942) | (176) | (10,118) | (9,377) | (322) | (9,699) | 2,900 | (54) | 2,846 |
| Interest income | 82 | — | 82 | 74 | — | 74 | 30 | — | 30 |
| Interest expense | (912) | — | (912) | (914) | — | (914) | (877) | — | (877) |
| Other income, net | 63 | 176 | 239 | 104 | 322 | 426 | 65 | 54 | 119 |
| Reorganization items | (320) | — | (320) | — | — | — | — | — | — |
| Income (loss) before income taxes | (11,029) | — | (11,029) | (10,113) | — | (10,113) | 2,118 | — | 2,118 |
| Income tax provision (benefit) ⁽¹⁾ | | | (3,407) | | | (3,295) | | | 427 |
| Net income (loss) | | | (7,622) | | | (6,818) | | | 1,691 |
| Preferred stock dividend requirement ⁽¹⁾ | | | 14 | | | 14 | | | 14 |
| Income (Loss) Available for Common Stock | | | \$ (7,636) | | | \$ (6,832) | | | \$ 1,677 |

⁽¹⁾ These items impacted earnings.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2019, 2018, and 2017, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased \$988 million, or 9%, in 2019 compared to 2018, primarily due to increased base revenues authorized in the 2017 GRC, 2019 GT&S, and TO20 rate cases.

The Utility's electric and natural gas operating revenues that impacted earnings increased \$39 million in 2018 compared to 2017, primarily due to increased base revenues authorized in the 2017 GRC, partially offset by tax benefits resulting from the Tax Act expected to be returned to customers.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased \$1,692 million, or 31%, in 2019 compared to 2018, primarily due to \$773 million in costs related to enhanced and accelerated inspections and repairs of transmission and distribution assets, with no similar charges in the same period in 2018. Additionally, the Utility recorded \$398 million in 2019 related to the Wildfires OII settlement, with no similar charge in the same period in 2018. Also, the Utility recorded \$237 million in disallowed costs for previously incurred capital expenditures in excess of adopted amounts in the 2019 GT&S rate case, with no similar charges in 2018.

The Utility's operating and maintenance expenses that impacted earnings increased \$363 million, or 7%, in 2018 compared to 2017, primarily due to \$209 million for clean-up and repair costs relating to the 2017 Northern California wildfires and the 2018 Camp fire, as compared to \$17 million relating to the 2017 Northern California wildfires charged in 2017. Also, the Utility recorded charges of \$187 million in additional legal and other costs relating to the 2017 Northern California wildfires and the 2018 Camp fire (the Utility recorded \$205 million for legal and other costs relating to the 2017 Northern California wildfires and the 2018 Camp fire in 2018, as compared to \$18 million in 2017). The Utility also recorded charges of \$121 million reflecting the additional write off of insurance premiums for single event coverage policies (the Utility recorded \$185 million in 2018 for the write off of insurance premiums, as compared to \$64 million in 2017). These increases were partially offset by a \$38 million reduction to the estimated disallowance for gas-related capital costs that were expected to exceed authorized amounts in 2018, compared to a \$47 million disallowance recorded in 2017 related to the Diablo Canyon settlement. Additionally, the increases were offset by a decrease in legal and other costs relating to the 2015 Butte fire of \$20 million in 2018 compared to 2017 (the Utility recorded \$40 million for legal and other costs relating to the 2015 Butte fire in 2018 as compared to \$60 million in 2017).

Wildfire-related claims, net of insurance recoveries

Costs related to wildfires that impacted earnings decreased by \$336 million in 2019 compared to 2018. The Utility recognized charges of \$11.4 billion and \$11.8 billion in 2019 and 2018, respectively, for wildfire-related claims, net of probable insurance recoveries, primarily associated with the 2018 Camp fire and 2017 Northern California wildfires.

Costs related to wildfires that impacted earnings increased by \$11.8 billion in 2018 compared to 2017. In 2018, the Utility recognized charges of \$14 billion, offset by probable insurance recoveries of \$2.2 billion associated with the 2018 Camp fire and 2017 Northern California wildfires. In 2017, the Utility recognized a charge of \$350 million, offset by probable insurance recoveries of \$350 million related to the 2015 Butte fire.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by \$197 million, or 6%, in 2019 compared to 2018, primarily due to capital additions. The Utility's depreciation, amortization, and decommissioning expenses increased by \$182 million, or 6%, in 2018 compared to 2017, primarily due to capital additions.

Interest Income

The Utility's interest income increased by \$8 million, or 11%, in 2019 compared to 2018. The Utility's interest income increased by \$44 million, or 147%, in 2018 as compared to 2017. The Utility's interest income is primarily affected by changes in regulatory balancing accounts and changes in interest rates.

Interest Expense

The Utility's interest expense decreased by \$2 million, or 0%, in 2019 compared to 2018. Beginning January 29, 2019 in connection with the Chapter 11 Cases, the Utility ceased recording interest on outstanding pre-petition debt subject to compromise. In the fourth quarter of 2019, following the Bankruptcy Court's December 30, 2019 memorandum decision in which it ruled that the UCC is entitled to post-petition interest at the Federal Judgment Rate of 2.59%, and pursuant to the terms of the Noteholder RSA, the Utility concluded that interest was probable of being an allowed claim and resumed recording interest on pre-petition debt subject to compromise. The Utility's interest expense increased by \$37 million, or 4%, in 2018 compared to 2017, primarily due to the issuance of long-term debt.

Other Income, Net

The Utility's other income, net decreased by \$41 million, or 39%, in 2019 compared to 2018, primarily due to a decrease in AFUDC due to equity ratio decreases resulting from the Chapter 11 filing and wildfire loss accruals. The Utility's other income, net increased by \$39 million, or 60%, in 2018 as compared to 2017, primarily due to an increase in AFUDC as the average balance of construction work in progress was higher in 2018 as compared to 2017.

Reorganization items, net

Reorganization items, net increased by \$320 million in 2019 compared to 2018, due to \$370 million of expenses directly associated with the Utility's Chapter 11 filing, partially offset by interest income of \$50 million, with no corresponding charges in 2018.

Income Tax Provision

The Utility's income tax benefit increased \$112 million in 2019 compared to 2018, primarily due to higher pre-tax losses.

The Utility's income tax provision decreased \$3.7 billion in 2018 compared to 2017. The decrease in the income tax provision and increase in the effective tax rate were primarily the result of pre-tax losses in 2018 versus pre-tax income in 2017, partially offset by a decrease in the corporate income tax rate from 35% to 21% as a result of the Tax Act.

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

| | 2019 | 2018 | 2017 |
|--|---------------|---------------|---------------|
| Federal statutory income tax rate | 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 % | 1.6 % |
| Effect of regulatory treatment of fixed asset differences ⁽²⁾ | 2.8 % | 3.6 % | (16.8)% |
| Tax credits | 0.1 % | 0.1 % | (1.1)% |
| Benefit of loss carryback | — % | — % | — % |
| Compensation Related ⁽³⁾ | — % | (0.1)% | (0.9)% |
| Tax Reform Adjustment ⁽⁴⁾ | — % | 0.1 % | 3.0 % |
| Other, net ⁽⁵⁾ | (0.5)% | — % | (0.7)% |
| Effective tax rate | 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.

Utility Revenues and Costs that did not Impact Earnings

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs. See below for more information.

Cost of Electricity

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. Cost of electricity also includes net sales (Utility owned generation and third parties) in the CAISO electricity markets. (See Note 10 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's total purchased power is driven by customer demand, net CAISO electricity market activities (purchases or sales), the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

| (in millions) | 2019 | 2018 | 2017 |
|---|-----------------|-----------------|-----------------|
| Cost of purchased power, net ⁽¹⁾ | \$ 2,809 | \$ 3,531 | \$ 4,039 |
| Fuel used in own generation facilities | 286 | 297 | 270 |
| Total cost of electricity | \$ 3,095 | \$ 3,828 | \$ 4,309 |

⁽¹⁾ Cost of purchased power, net decreased for the year ended December 31, 2019, compared to 2018, primarily due to lower Utility electric customer demand, driven by customer departures to CCAs and DA providers, and by higher net sales in the CAISO electricity markets.

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage and transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 10 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

| (in millions) | 2019 | 2018 | 2017 |
|---|---------------|---------------|---------------|
| Cost of natural gas sold | \$ 622 | \$ 561 | \$ 627 |
| Transportation cost of natural gas sold | 112 | 110 | 119 |
| Total cost of natural gas | \$ 734 | \$ 671 | \$ 746 |

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2019, 2018, and 2017, no material amounts were incurred above authorized amounts.

Other Income, Net

The Utility's other income, net that did not impact earnings includes pension and other post-retirement benefit costs that fluctuate primarily from market and interest rate changes.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement. The DIP Credit Agreement provides for \$5.5 billion in senior secured superpriority debtor in possession credit facilities in the form of (i) a revolving credit facility in an aggregate amount of \$3.5 billion (the “DIP Revolving Facility”), including a \$1.5 billion letter of credit subfacility, (ii) a term loan facility in an aggregate principal amount of \$1.5 billion (the “DIP Initial Term Loan Facility”) and (iii) a delayed draw term loan facility in an aggregate principal amount of \$500 million (the “DIP Delayed Draw Term Loan Facility,” together with the DIP Revolving Facility and the DIP Initial Term Loan Facility, the “DIP Facilities”), subject to the terms and conditions set forth therein. On 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. (For more information on the DIP Credit Agreement, see “DIP Credit Agreement” below and Note 5 of the Notes to the Consolidated Financial Statements in Item 8.)

For the duration of the Chapter 11 Cases, the Utility’s ability to fund operations, finance capital expenditures and pay other ongoing expenses and make distributions to PG&E Corporation will primarily depend on the levels of its operating cash flows and availability under the DIP Credit Agreement. The Utility expects that the DIP Facilities will provide it with sufficient liquidity to fund its ongoing operations, including its ability to provide safe service to customers, during the Chapter 11 Cases. For the duration of the Chapter 11 Cases, PG&E Corporation’s ability to fund operations and pay other ongoing expenses will primarily depend on cash on hand and intercompany transfers. In the event that PG&E Corporation’s and the Utility’s capital needs increase materially due to unexpected events or transactions, additional financing outside of the DIP Facilities may be required, which would be subject to approval by the Bankruptcy Court. Such approval is not assured. For more information on PG&E Corporation’s and the Utility’s material commitments for capital expenditures, see “Regulatory Matters” below.

During 2018 and January 2019, PG&E Corporation’s and the Utility’s credit ratings were subject to multiple downgrades by Fitch, S&P and Moody’s including to ratings below investment grade and ultimately to “D” or low “C” ratings. In the first quarter of 2019, Moody’s and Fitch withdrew each of their credit ratings for PG&E Corporation and the Utility as a result of the Chapter 11 Cases. As a result of PG&E Corporation’s and the Utility’s credit ratings ceasing to be rated at investment grade, the Utility has been required to post collateral under its commodity purchase agreements and certain other obligations. In addition, PG&E Corporation and the Utility may be required to post additional collateral in respect of certain other obligations, including workers’ compensation and environmental remediation obligations. (See Notes 10 and 15 of the Notes to the Consolidated Financial Statements in Item 8.)

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. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds.

Financial Resources

Acceleration of Pre-Petition Debt Obligations

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 Accelerated Direct Financial Obligations. Accordingly, as a result of the commencement of the Chapter 11 Cases, the principal amount of the Accelerated Direct Financial Obligations, together with accrued interest thereon, and in case of certain indebtedness, premium, if any, thereon, immediately became due and payable. However, any efforts to enforce such payment obligations are automatically stayed as of the Petition Date, and are subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. The material Accelerated Direct Financial Obligations include the 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 disclosed in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

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 DIP Facilities will mature on December 31, 2020, subject to the Utility's option to extend the maturity to December 31, 2021 if certain terms and conditions are satisfied, including the payment of an extension fee. The Utility paid customary fees and expenses in connection with obtaining the DIP Facilities.

On February 1, 2019, the Utility borrowed \$350 million under the DIP Revolving Facility. On April 3, 2019, the Utility borrowed \$1.5 billion under the DIP Initial Term Loan Facility and received the proceeds of such borrowing, net of original issue discount and repayment of the \$350 million in outstanding borrowings under the DIP Revolving Facility. The DIP Initial Term Loan Facility matures on December 31, 2020 (subject to an extension option described further below) and bears interest at a spread of 225 basis points over LIBOR.

On January 29, 2020, the Utility borrowed \$500 million under the DIP Delayed Draw Term Loan Facility. As of February 13, 2020, the Utility had outstanding borrowings of \$1.5 billion under the DIP Initial Term Loan Facility, \$500 million under the DIP Delayed Draw Term Loan Facility, and \$751 million in face amount of letters of credit outstanding under the DIP Revolving Facility. As of February 13, 2020, there were undrawn commitments of \$2.7 billion on the DIP Revolving Facility.

Debt Commitment Letters

On October 11, 2019, PG&E Corporation and the Utility entered into the Debt Commitment Letters with the Commitment Parties, which were subsequently amended on November 18, 2019, December 20, 2019, January 30, 2020, and February 14, 2020, 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 as borrower thereunder and (b) a \$5 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 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 set forth in the Debt Commitment Letters. PG&E Corporation and the Utility will pay customary fees and expenses in connection with obtaining the Facilities. If the entire \$10.825 billion of bridge commitments remain outstanding as of June 30, 2020, the aggregate commitment fees payable by PG&E Corporation and the Utility would be approximately \$75 million.

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, (2) reduce the amount of proceeds from the issuance of equity that PG&E Corporation has to receive as a condition to funding from \$12.0 billion to \$9.0 billion, and (3) 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.

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. (See "Anticipated Sources and Uses for Chapter 11 Emergence and Related Financings" below and "Plan of Reorganization, RSAs, Equity Backstop Commitments and Debt Commitment Letters" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.)

On October 23, 2019, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court seeking approval of 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.

Equity Financings

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the year ended December 31, 2019.

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. The proceeds from these sales were used for general corporate purposes. 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.

PG&E Corporation expects to issue new shares of PG&E Corporation common stock for up to \$9.0 billion of proceeds at or prior to emergence from Chapter 11 in order to finance the Proposed Plan. The structure, terms and conditions of any such equity issuance 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. There can be no assurance that any such equity offering would be successful. PG&E Corporation has obtained the Backstop Commitment Letters providing for equity funding of up to \$12.0 billion to finance the transactions contemplated by the Proposed Plan. In the event that new equity offerings do not raise at least \$9.0 billion of proceeds, or if additional capital is required, PG&E Corporation may draw on the Backstop Commitments for equity funding of up to \$12.0 billion, subject to satisfaction or waiver by the Backstop Parties of the conditions set forth therein. (See "Anticipated Sources and Uses for Chapter 11 Emergence and Related Financings" below and "Plan of Reorganization, RSAs, Equity Backstop Commitments and Debt Commitment Letters" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.) The hearing on PG&E Corporation's and the Utility's motion to approve the Backstop Commitment Letters and certain related matters is scheduled for February 26, 2020.

Anticipated Sources and Uses for Chapter 11 Emergence and Related Financings

PG&E Corporation and the Utility expect that the funding for the Proposed Plan will consist of both new debt and equity for both PG&E Corporation and the Utility as well as other sources of funding totaling approximately \$58 billion.

Expected Sources

The expected sources of such funds are summarized in the following table:

(in millions)

| | | |
|--|-----------|---------------|
| Equity issuance for cash ⁽¹⁾ | \$ | 9,000 |
| Equity issued for Fire Victim Trust ⁽²⁾ | | 6,750 |
| New PG&E Corporation Debt ⁽³⁾ | | 4,750 |
| Reinstated Utility Debt ⁽⁴⁾ | | 9,575 |
| New Utility Debt ⁽⁵⁾ | | 23,775 |
| Insurance Proceeds ⁽⁶⁾ | | 2,200 |
| Cash at Emergence ⁽⁷⁾ | | 1,600 |
| Total Sources | \$ | 57,650 |

⁽¹⁾ Equity issuance for cash represents expected proceeds from the sale of shares of common stock of PG&E Corporation through one or more public offerings, private offerings, a rights offering or drawings under the Backstop Commitments. The terms of any such issuance are governed by the terms of the Backstop Commitment Letters. Although the Proposed Plan contemplates \$9.0 billion of equity, the Backstop Commitment Letters permit up to \$12.0 billion of equity to be drawn from the Backstop Commitments. (See "Plan of Reorganization, RSAs, Equity Backstop Commitments and Debt Commitment Letters" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽²⁾ Equity issued to Fire Victim Trust represents new shares of common stock of PG&E Corporation to be issued to the Fire Victim Trust as provided in the Proposed Plan. (See "Restructuring Support Agreement with the TCC" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽³⁾ New PG&E Corporation Debt represents one or more issuances of new debt securities or bank debt of PG&E Corporation.

⁽⁴⁾ Reinstated Utility Debt represents pre-petition debt of the Utility that is expected to be reinstated on the Effective Date pursuant to the Proposed Plan. (See "Restructuring Support Agreement with the Ad Hoc Noteholder Committee" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽⁵⁾ New Utility Debt represents one or more issuances of new debt securities or bank debt of the Utility, expected to be comprised 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. As described below, \$6.0 billion of such new debt securities or bank debt is expected to be repaid with the proceeds of a new securitization transaction after the Effective Date. (See "Restructuring Support Agreement with the Ad Hoc Noteholder Committee" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽⁶⁾ Insurance Proceeds represents proceeds of PG&E Corporation's and the Utility's liability insurance policies for wildfire events. (See "Insurance" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽⁷⁾ Cash at Emergence represents projected cash on hand at PG&E Corporation and the Utility as of the Effective Date.

Expected Uses

The expected uses of funds under the Proposed Plan are summarized in the following table:

(in millions)

| | | |
|---|-----------|---------------|
| Fire Claims ⁽¹⁾ | \$ | 24,150 |
| Contributions to Wildfire Fund ⁽²⁾ | | 5,000 |
| Debtor-In-Possession Financing ⁽³⁾ | | 2,000 |
| Pre-petition Debt ⁽⁴⁾ | | 22,180 |
| Trade Claims and Other Costs ⁽⁵⁾ | | 2,300 |
| Accrued Interest ⁽⁶⁾ | | 1,270 |
| Cash ⁽⁷⁾ | | 750 |
| Total Uses | \$ | 57,650 |

⁽¹⁾ Fire Claims (at Emergence) represents compensation to be paid on the Effective Date to holders of wildfire-related claims to resolve their claims pursuant to the Proposed Plan. The total compensation of \$24.15 billion consists of (i) \$12.15 billion to be paid in cash and stock to the Fire Victim Trust, (ii) \$11.0 billion to be paid to holders of subrogated insurance claims and (iii) \$1.0 billion to be paid to the Supporting Public Entities. (See "Plan Support Agreements with Public Entities", "Restructuring Support Agreement with Holders of Subrogation Claims" and "Restructuring Support Agreement with the TCC" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽²⁾ Contribution to Wildfire Fund represents required payments under AB 1054 for the Utility to participate in the Wildfire Fund. These payments are comprised of an initial contribution of approximately \$4.8 billion and annual contributions of approximately \$193 million. (See "Wildfire Fund under AB 1054" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽³⁾ Debtor-In-Possession Financing represents the projected amount that will be required in order to repay all amounts outstanding under the DIP Credit Agreement on the Effective Date.

⁽⁴⁾ Pre-petition Debt represents the aggregate principal amount of pre-petition debt of PG&E Corporation or the Utility to be repaid or refinanced on the Effective Date, consisting of (i) \$650 million of pre-petition debt of PG&E Corporation to be repaid in cash pursuant to the Proposed Plan, (ii) \$6.2 billion of pre-petition senior notes of the Utility to be exchanged for New Utility Long-Term Notes pursuant to the Proposed Plan, (iii) \$1.75 billion of pre-petition senior notes of the Utility to be exchanged for New Utility Short-Term Notes pursuant to the Proposed Plan and (iv) \$3.9 billion of pre-petition indebtedness of the Utility to be exchanged for Utility Funded Debt Exchange Notes pursuant to the Proposed Plan, (v) \$9.575 billion of pre-petition senior notes of the Utility to be reinstated pursuant to the Proposed Plan and (vi) \$100 million of Pollution Control Bonds (Series 2008F and 2010E) to be repaid in cash pursuant to the Proposed Plan. (See "Restructuring Support Agreement with the Ad Hoc Noteholder Committee" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.)

⁽⁵⁾ Trade Claims and Other Costs represents estimated trade claims and other costs, including trade payables and transaction fees, to be paid by PG&E Corporation or the Utility on the Effective Date.

⁽⁶⁾ Accrued Interest represents the estimated amount of accrued interest that will be paid by PG&E Corporation or the Utility on the Effective Date.

⁽⁷⁾ Cash represents \$750 million of cash remaining on the balance sheet as of the Effective Date.

The table above does not include \$1.35 billion of payments to be made to the Fire Victim Trust after the Effective Date of the Proposed Plan pursuant to a tax benefit monetization agreement. Pursuant to this tax benefit monetization agreement, PG&E Corporation and the Utility will use the first \$1.35 billion of wildfire-related tax net operating losses (the "Wildfire NOLs") in order to make payments to the Fire Victim Trust, which payments are expected to be \$650 million on or before January 15, 2021 and \$700 million on or before January 15, 2022. In addition, the table above does not include any expected post-Effective Date securitization transaction. As described below under the heading "Potential Securitization Transaction," the economic benefits of the Wildfire NOLs in excess of the first \$1.35 billion would be used to support the expected post-Effective Date securitization transaction.

Potential Securitization Transaction

PG&E Corporation and the Utility expect to file an application with the CPUC seeking authorization for a post-emergence \$7.0 billion securitization transaction that is rate-neutral, on average, to customers, with the proceeds used to refinance \$6.0 billion of new Utility debt and fund a portion of the \$1.35 billion payment due to the Fire Victim Trust post-Effective Date. In this context, a securitization refers to a financing transaction where the Utility or a special purpose financing vehicle issues new debt that is secured by the proceeds of a new recovery charge to Utility customers. A rate-neutral securitization means that the Utility will propose to offset the new recovery charges with customer credits, so that on a net present value basis, customers do not experience an increase in utility rates. The Utility would be able to support these credits based on the tax savings from the Wildfire NOLs and other sources. In other words, the funds retained by the Utility that would have otherwise been used to pay taxes can be used for other purposes, reducing the amount that the Utility needs to collect from customers (thereby using the Wildfire NOLs to "fund" the credit).

The foregoing description of anticipated sources and uses of funding for the Proposed Plan includes “forward-looking statements” within the meaning of Section 27A of the Securities Act, including statements about the expected sources and uses of funding, expected financing transactions (including the potential securitization) and projected balances of assets and liabilities (including cash on hand, accrued interest, trade payables and other amounts). This description reflects PG&E Corporation’s and the Utility’s expectations as of the date of this filing and remains subject to change. (See “Forward-Looking Statements” at the beginning of this Annual Report on Form 10-K).

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. (See Note 6 of the Notes to the Consolidated Financial Statements in Item 8.)

Utility Cash Flows

The Utility’s cash flows were as follows:

| (in millions) | Year Ended December 31, | | |
|--|-------------------------|---------------|---------------|
| | 2019 | 2018 | 2017 |
| Net cash provided by operating activities | \$ 4,810 | \$ 4,704 | \$ 5,916 |
| Net cash used in investing activities | (6,378) | (6,564) | (5,650) |
| Net cash provided by financing activities | 1,395 | 2,708 | 110 |
| Net change in cash and cash equivalents | \$ (173) | \$ 848 | \$ 376 |

Operating Activities

The Utility’s cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During 2019, net cash provided by operating activities increased by \$106 million compared to 2018. This increase was due to a decrease in interest paid from \$773 million to \$7 million as a result of the automatic stay as of the Petition Date. Additionally, income taxes paid decreased from \$59 million in 2018 to zero in 2019. These decreases in amounts paid were offset by an increase in amounts paid for reorganization items, and enhanced and accelerated inspections and repairs of transmission and distribution assets in 2019, with no similar payments in 2018, partially offset by additional amounts not paid due to the automatic stay as of the Petition Date.

During 2018, net cash provided by operating activities decreased by \$1.2 billion compared to 2017. This decrease was due to an increase in costs for clean-up and repair, and legal and other costs related to the 2018 Camp fire and 2017 Northern California wildfires, as well as enhanced vegetation management work, and due to fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections and vendor billings and payments. Additionally, the Utility paid \$59 million in income taxes in 2018, as compared to receiving a refund of \$162 million in 2017.

The Utility will continue to operate its business as a debtor in possession under the jurisdiction of the Bankruptcy Court and in accordance with applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. Future cash flow from operating activities will be affected by various ongoing activities, including:

- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with current and future enforcement, litigation, and regulatory matters (see Note 14 and “Enforcement and Litigation Matters” in Note 15 of the Notes to the Consolidated Financial Statements in Item 8. and Item 3. Legal Proceedings for more information);
- the timing and amount of substantially increasing costs in connection with the 2019 Wildfire Mitigation Plan that are not currently being recovered in rates (see “Regulatory Matters” below for more information);
- the timing and amount of premium payments related to wildfire insurance (see “Wildfire Insurance” in Note 15 of the Notes to the Consolidated Financial Statements in Item 8 for more information);
- the Tax Act, which may accelerate the timing of federal tax payments and reduce revenue requirements, resulting in lower operating cash flows depending on the timing of wildfire payments; and

- the timing and outcomes of the 2020 GRC, FERC TO18, TO19 and TO20 rate cases, NDCTP, 2018 and 2019 CEMA filings, and other ratemaking and regulatory proceedings.

The Utility had material obligations outstanding as of the Petition Date, including claims related to the 2018 Camp fire and 2017 Northern California wildfires. 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. Future cash flows will be materially impacted by the timing and outcome of the Chapter 11 Cases.

Investing Activities

Net cash used in investing activities decreased by \$186 million during 2019 as compared to 2018 primarily due to a decrease in cash paid for capital expenditures as a result of the automatic stay as of the Petition Date. Net cash used in investing activities increased by \$914 million during 2018 as compared to 2017 primarily due to an increase of approximately \$873 million in capital expenditures. The Utility's investing activities primarily consist of the construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately \$7.6 billion in capital expenditures in 2020.

Financing Activities

During 2019, net cash provided by financing activities decreased by \$1.3 billion as compared to 2018. This decrease was primarily due to \$2.9 billion of net borrowings under revolving credit facilities in 2018, partially offset by \$1.5 billion of net borrowings under the DIP Initial Term Loan Facility in 2019.

Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2019:

| (in millions) | Payment due by period | | | | |
|---|-----------------------|-----------------|-----------------|----------------------|------------------|
| | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years | Total |
| Utility | | | | | |
| Long-term debt ⁽¹⁾ | \$ 2,255 | \$ 2,564 | \$ 3,404 | \$ 22,626 | \$ 30,849 |
| Purchase obligations ⁽²⁾ | | | | | |
| Power purchase agreements | 2,952 | 5,474 | 4,274 | 23,298 | 35,998 |
| Natural gas supply, transportation, and storage | 411 | 310 | 310 | 346 | 1,377 |
| Nuclear fuel agreements | 151 | 118 | 96 | — | 365 |
| Pension and other benefits ⁽³⁾ | 342 | 684 | 684 | 342 | 2,051 |
| Operating leases ⁽²⁾ | 45 | 70 | 38 | 111 | 264 |
| Preferred dividends ⁽⁴⁾ | 14 | 28 | 28 | — | 70 |
| PG&E Corporation | | | | | |
| Long-term debt ⁽¹⁾ | 354 | — | — | — | 354 |
| Total Contractual Commitments | \$ 6,524 | \$ 9,248 | \$ 8,834 | \$ 46,723 | \$ 71,328 |

- (1) Includes interest payments over the terms of the debt at contractual rates. Interest is calculated using the applicable interest rate at December 31, 2019 and outstanding principal for each instrument with the terms ending at each instrument's maturity. The commencement of the Chapter 11 Cases constituted an event of default or termination event under the long-term debt summarized in the table above. For more information, see "Liquidity and Financial Resources - Financial Resources - Acceleration of Pre-petition Debt Obligations" in Item 7. MD&A and Note 5 of the Notes to the Consolidated Financial Statements in Item 8.
- (2) See "Purchase Commitments" and "Other Commitments" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.
- (3) See Note 12 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.
- (4) Beginning with the three-month period ending January 31, 2018, quarterly cash dividends on the Utility's preferred stock were suspended. While the timing of cumulative dividend payments is uncertain, it is assumed for the table above to be payable within a fixed period of five years based on historical performance. (See Note 7 of the Consolidated Financial Statements in Item 8.)

The contractual commitments table above excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 9 of the Notes to the Consolidated Financial Statements in Item 8. (For more information, see "Liquidity and Financial Resources - Financial Resources - Acceleration of Pre-petition Debt Obligations" in Item 7. MD&A.)

Subject to certain exceptions, under the Bankruptcy Code, PG&E Corporation and the Utility may assume, assign or reject certain executory contracts and unexpired leases, subject to the approval of the Bankruptcy Court and satisfaction of certain other conditions. Generally, the rejection of an executory contract or unexpired lease is treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves PG&E Corporation and the Utility of performing their respective future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Generally, the assumption of an executory contract or unexpired lease will require PG&E Corporation or the Utility, as applicable, to cure existing monetary and non-monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with PG&E Corporation or the Utility in this Annual Report on Form 10-K, including where applicable a quantification of the obligations under any such executory contract or unexpired lease, is qualified by any overriding assumption or rejection rights PG&E Corporation or the Utility, as applicable, has under the Bankruptcy Code. Further, nothing herein is or shall be deemed to be an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and PG&E Corporation and the Utility expressly reserve all of their rights with respect thereto.

Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed under "Purchase Commitments" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Notes 14 and 15 of the Notes to the Consolidated Financial Statements in Item 8. and Legal Proceedings in Item 3 that are incorporated by reference herein. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

U.S. District Court Matters and Probation

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

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

On January 9, 2019, the court issued an order (the "January 9 Order") proposing to add new conditions of probation that would require the Utility, among other things, to:

- prior to June 21, 2019, "re-inspect all of its electrical grid and remove or trim all trees that could fall onto its power lines, poles or equipment in high-wind conditions, . . . identify and fix all conductors that might swing together and arc due to slack and/or other circumstances under high-wind conditions[,] identify and fix damaged or weakened poles, transformers, fuses and other connectors [and] identify and fix any other condition anywhere in its grid similar to any condition that contributed to any previous wildfires,"
- "document the foregoing inspections and the work done and . . . rate each segment's safety under various wind conditions" and
- at all times from and after June 21, 2019, "supply electricity only through those parts of its electrical grid it has determined to be safe under the wind conditions then prevailing."

On January 30, 2019, the court found that the Utility had violated a condition of its probation with respect to reporting requirements related to the 2017 Honey fire. Also, on January 30, 2019, the court ordered the Utility to submit to the court on February 6, 2019 the 2019 Wildfire Mitigation Plan that the Utility was required to submit to the CPUC by February 6, 2019 in accordance with SB 901, and invited interested parties to comment on such plan by February 20, 2019.

On March 5, 2019, the court issued an order proposing to add new conditions of probation that would require the Utility, among other things, to:

- "fully comply with all applicable laws concerning vegetation management and clearance requirements;"
- "fully comply with the specific targets and metrics set forth in its wildfire mitigation plan, including with respect to enhanced vegetation management;"
- submit to "regular, unannounced inspections" by the Monitor "of PG&E's vegetation management efforts and equipment inspection, enhancement, and repair efforts" in connection with a requirement that the Monitor "assess PG&E's wildfire mitigation and wildfire safety work;"
- "maintain traceable, verifiable, accurate, and complete records of its vegetation management efforts" and report to the Monitor monthly on its vegetation management status and progress; and
- "ensure that sufficient resources, financial and personnel, including contractors and employees, are allocated to achieve the foregoing" and to forgo issuing "any dividends until [the Utility] is in compliance with all applicable vegetation management requirements as set forth above."

On April 3, 2019, the court issued an order imposing the new terms though amended the second condition to clarify that "[f]or purposes of this condition, the operative wildfire mitigation plan will be the plan ultimately approved by the CPUC."

On May 14, 2019, the court imposed two additional conditions of probation: (1) requiring that PG&E Corporation's Board of Directors, Chief Executive Officer, senior executives, the Monitor and U.S. Probation Officer visit the towns of Paradise and San Bruno "to gain a firsthand understanding of the harm inflicted on those communities;" and (2) requiring that a committee of PG&E Corporation's Board of Directors assume responsibility for tracking progress of the 2019 Wildfire Mitigation Plan and the additional terms of probation regarding wildfire safety, reporting in writing to the full Board at least quarterly. The court also stated that it was not going to rule at this time on whether the court has authority to extend probation and would leave that question "in abeyance." The court did not discuss whether the Monitor reports should be made public. Members of PG&E Corporation's Board of Directors and senior management attended site visits to the Town of Paradise on June 7, 2019 and the City of San Bruno on July 16, 2019, which were coordinated by the U.S. Probation Officer overseeing the Utility's probation. In addition, the Compliance and Public Policy Committee, a committee of PG&E Corporation's Board of Directors, will be responsible for tracking the Utility's progress against the Utility's wildfire mitigation plan, as approved by the CPUC, and compliance with the terms of the Utility's probation regarding wildfire safety.

On November 12, 2019, the court held a hearing related to the Utility's San Bruno community service. At the hearing, representatives from San Bruno asked the court to approve allowing the Utility to satisfy the remainder of its community service requirements by making a \$3 million payment that would be used for the purpose of hard costs incurred as part of the Crestmoor Canyon Wildfire Mitigation Project. The court approved the request and ordered the parties to jointly offer language regarding revising the Utility's conditions of probation to effectuate this change. The parties conferred and agreed on proposed language, which the Utility submitted to the court as a proposed order on November 27, 2019. The court signed the proposed order that same day, and on December 10, 2019 confirmed receipt of the \$3 million payment from the Utility in compliance with the November 27th Order.

On January 16, 2020, the court issued an order to show cause noting that the Utility had admitted it was not in full compliance with the following conditions of probation: (1) fully complying with all applicable laws concerning vegetation management; and (2) fully complying with specific targets and metrics set forth in its wildfire mitigation plan. The court set a show cause hearing for February 19, 2020, to discuss why a further condition of probation should not be imposed requiring the Utility to hire sufficient crews to enable it to fully comply with the laws and its wildfire mitigation plan concerning vegetation management. The Utility submitted its response to the court on February 12, 2020.

On January 24, 2020, the court issued an additional order to show cause as to why, going forward, the Utility should not restrict all bonuses and other incentives for supervisors and above exclusively to achieving its wildfire mitigation plan and other safety goals. The Utility submitted its response to the court on February 12, 2020. A hearing in connection with this order is scheduled for February 19, 2020.

On February 4, 2020, the court issued a request for amended responses and further questions to be answered by the Utility relating to certain of the court's requests for wildfire and PSPS related information. The Utility has until February 18, 2020 to submit its responses to these questions.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC, and other federal and state regulatory agencies. The resolutions of the proceedings described below and other proceedings may materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Rate Cases

Application for Wildfire Mitigation and Catastrophic Events Interim Rates

On February 7, 2020, the Utility filed an interim relief application seeking \$899 million in interim rates related to certain electric distribution costs recorded in the following memorandum accounts: WMPMA, FRMMA, FHPMA, and CEMA. The costs pertain mainly to the years 2017-2019. The application addresses costs recorded in: (i) the WMPMA and FRMMA to comply with the 2019 WMP and other wildfire mitigation costs not otherwise recoverable through rates, (ii) the FHMPA to comply with various fire safety rulemakings through 2019, and (iii) the CEMA for responding to, and restoring customer service after, certain storms and fires occurring in 2019.

After removing the amounts agreed to be not subject for recovery pursuant to the 2017 Northern California Wildfires and the 2018 Camp Fire OII settlement agreement (submitted to the CPUC on December 17, 2019), the total electric distribution costs related to the above activities are approximately \$1.7 billion in expense and capital expenditures. This amount translates to an electric distribution revenue requirement of approximately \$1 billion. The interim rate relief sought in this application is 85% of that revenue requirement. The Utility's application calls for a CPUC decision by July of 2020. In its interim rate relief application, the Utility also proposes to file one or more detailed application(s) with the CPUC to determine the reasonableness of the above-described costs later in 2020.

If approved, by the CPUC, the interim relief request would increase electric distribution rates over a 17-month period beginning in August 2020. If the CPUC determines in those later application(s) that the interim rates were too high, the Utility will refund any overcollections to customers with interest based on the applicable commercial paper rate.

The Utility's application also requests a CPUC ruling that would allow for interim rate relief when the recorded balance in certain memorandum accounts exceeds a threshold of \$100 million.

The Utility is unable to predict the timing and outcome of this application.

Application for Recovery of Costs Recorded in the Wildfire Expense Memorandum Account

On February 7, 2020, the Utility filed an application seeking recovery of certain costs recorded in the WEMA. In the application, the Utility seeks recovery of \$498.7 million for the cost of insurance premiums paid by the Utility between July 26, 2017 through December 31, 2019 that is incremental to the insurance costs already authorized in the 2017 GRC or sought to be authorized in rates in the 2020 GRC. These incremental costs are not associated with any specific wildfire event. The application does not seek recovery of wildfire claims or associated legal costs eligible for recording to WEMA. The Utility has proposed a schedule for the proceeding that requests a final decision by the end of 2020 and costs to be recovered during 2021.

The Utility is unable to predict the timing and outcome of this application.

Application for a Waiver of the Capital Structure Condition

The CPUC's capital structure decisions require the Utility to maintain a 52% equity ratio on average over the period that the authorized capital structure is in place, and to file an application for a waiver to the capital structure condition if an adverse financial event reduces its equity ratio by 1% or more. The CPUC's decisions state that the Utility shall not be considered in violation of these conditions during the period the waiver application is pending resolution. 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.

On April 30, 2019, the CPUC held a prehearing conference, and on May 29, 2019, the CPUC issued a scoping memo and ruling on issues for briefing. Subsequently, among other things, the Utility filed a motion with the CPUC to notify the CPUC of a decline in its equity ratio to approximately 34% at June 30, 2019. On November 12, 2019, the Utility submitted a second motion to the CPUC to notify the CPUC of an additional decline in its equity ratio to approximately 30.4%, based on information reported in its Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, primarily related to non-cash charges related to the 2018 Camp fire and the 2017 Northern California wildfires. The Utility submitted additional pleadings in December 2019, notifying the CPUC of additional charges due to the 2017 Northern California wildfires and the 2018 Camp fire, and describing the impacts on its equity percentage if the charges were added to the Utility's financial information reported in its Form 10-Q for the quarterly period ending September 30, 2019. However, the Utility indicated that its equity percentage at December 31, 2019 would not be known until the financial information for the period ending December 31, 2019 is reported in the 2019 Form 10-K.

On November 20, 2019, the assigned ALJ issued a ruling with questions for the Utility to answer. On January 21, 2020, the Utility filed responses to the questions presented in the ALJ's November 20, 2019 ruling. In its responses, among other things, the Utility recommended that the CPUC grant the Utility a waiver of the capital structure condition, and transfer the issue of the Utility's capital structure waiver to the OII to consider and resolve the continuance or end of the waiver in that proceeding in connection with the Utility's Proposed Plan of Reorganization.

The Utility is unable to predict the timing and outcome of its waiver application.

2020 Cost of Capital Proceeding

On December 19, 2019, the CPUC approved a final decision in the 2020 Cost of Capital proceeding, maintaining the Utility's return on common equity for the three-year period beginning January 1, 2020 at 10.25%, as compared to 12% requested by the Utility. The Utility's annual cost of capital adjustment mechanism also remains unchanged. The decision maintains the common equity component of the Utility's capital structure at 52%, as requested by the Utility, and reduces its preferred stock component from 1% to 0.5%, also as requested by the Utility. The decision also approves the cost of debt requested by the Utility.

The following table compares the cost of capital currently authorized (in the Utility's 2019 Gas Transmission and Storage rate case and the 2017 General Rate Case) with those in the decision:

| | 2019 Authorized | | | 2020 Adopted | | |
|---|-----------------|-------------------|---------------|--------------|-------------------|---------------|
| | Cost | Capital Structure | Weighted Cost | Cost | Capital Structure | Weighted Cost |
| Return on common equity | 10.25 % | 52.00 % | 5.33 % | 10.25 % | 52.00 % | 5.33 % |
| Preferred stock | 5.60 % | 1.00 % | 0.06 % | 5.52 % | 0.50 % | 0.03 % |
| Long-term debt | 4.89 % | 47.00 % | 2.30 % | 5.16 % | 47.50 % | 2.45 % |
| Weighted average cost of capital | | | 7.69 % | | | 7.81 % |

The Utility estimates that the Utility's 2020 revenue requirement associated with the authorized cost of capital is approximately \$30 million more than the authorized revenue requirement at the 2019 authorized cost of capital.

The decision does not take a position or establish any orders pertaining to whether the Utility should be required to submit a new cost of capital application following its emergence from Chapter 11 bankruptcy. The decision defers that issue to the CPUC's separate order instituting investigation into issues relating to the Utility's bankruptcy.

2017 General Rate Case

On May 11, 2017, the CPUC issued a final decision in the Utility's 2017 GRC, which determined the annual amount of base revenues (or "revenue requirements") that the Utility is authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The final decision approved, with certain modifications, the settlement agreement that the Utility, PAO, TURN, and 12 other intervening parties jointly submitted to the CPUC on August 3, 2016. Consistent with the amounts proposed in the settlement agreement, the final decision approved a revenue requirement increase of \$88 million for 2017, with additional increases of \$444 million in 2018 and \$361 million in 2019.

On September 24, 2018, the CPUC approved the Utility's advice letter proposal to make a one-time reduction to revenues by approximately \$21 million. This advice letter was directed by an ALJ ruling in response to the Utility's \$300 million expense reduction announcement in January 2017.

Also, as a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2017 GRC proposing to reduce revenue requirements by \$267 million and \$296 million for 2018 and 2019, respectively, and increase rate base by \$199 million and \$425 million for 2018 and 2019, respectively. On August 15, 2019, a final decision on the PFM was issued directing the Utility to consult with the CPUC's Energy Division to ensure that its calculations include the cost of removal component of book depreciation when calculating the amortization of protected excess deferred income taxes using the ARAM and to quantify the amount of unprotected excess deferred taxes, which can be returned to ratepayers without following the ARAM. In compliance with the decision, on September 13, 2019, the Utility filed an advice letter with the revised calculations and the length of time the revenue requirement reductions would be amortized in rates. On October 17, 2019, the CPUC approved the Utility's advice letter approving a revised computation of the effects of the Tax Act on the revenue requirements, resulting in a \$282 million reduction to the 2018 revenue requirement and a \$291 million reduction to the 2019 revenue requirement. The Utility will incorporate these revenue requirement reductions into rates beginning on January 1, 2020 and later in 2020, along with other anticipated changes, such as the 2020 GRC phase one. The IRS is expected to provide additional guidance on ARAM. This IRS guidance may impact the Utility's calculation of the related revenue requirement. It is uncertain when the IRS guidance may be issued.

The Utility provided an update of the cost effectiveness study for the SmartMeter™ Upgrade project to the CPUC on July 10, 2017. On October 24, 2019, the CPUC adopted a final decision that finds (i) the July 10, 2017 study is a thorough and complete update of the cost-effectiveness of the project and (ii) the Utility should submit an updated version of the cost effectiveness study as a stand-alone exhibit in each GRC Phase I application that the Utility files in the future.

2020 General Rate Case

On December 20, 2019, the Utility together with the PAO, TURN, CUE, the CPUC’s Office of the Safety Advocate, the National Diversity Coalition, the Center for Accessible Technology, the Small Business Utility Advocates, and California City County Street Light Association filed a motion with the CPUC seeking approval of a settlement agreement that resolves all of the issues raised by these parties in the Utility’s 2020 GRC.

Revenue Requirements and Attrition Year Revenues

The settlement agreement proposes that the Utility’s 2019 authorized revenue requirement of \$8.5 billion be increased by \$575 million, effective January 1, 2020, to \$9.1 billion. The settlement agreement further provides for an increase of \$318 million to the authorized 2020 revenue requirement in 2021 and an additional increase of \$367 million in 2022, as shown in the table below.

The table below summarizes the differences between the amount of revenue requirement increases included in the Utility’s application on December 13, 2018, as updated in its testimony on November 1, 2019, and the amount in the settlement agreement:

(in millions)

| Year | Increase Requested in GRC Application | Increase Proposed in Settlement Agreement ⁽¹⁾ | Difference (Decrease from GRC Application) |
|-------------|--|---|---|
| 2020 | \$ 1,003 | \$ 575 | \$ (428) |
| 2021 | 356 | 318 | (38) |
| 2022 | 481 | 367 | (114) |

⁽¹⁾ The settlement amounts reflect the impacts of AB 1054.

The following table shows the differences, based on line of business and cost category, between the amount of revenue requirements requested by the Utility in its GRC application and the amount in the settlement agreement, as well as the differences between the 2019 authorized revenue requirements and (i) the GRC application and (ii) the amounts in the settlement agreement:

| (in millions) | Amounts Requested in GRC Application | Amounts Proposed in Settlement Agreement | Difference (Decrease) | Increase / (Decrease) 2019 Amounts vs. GRC Application | Increase / (Decrease) 2019 GRC vs. Settlement Agreement |
|---|---|---|--------------------------|---|---|
| Lines of Business: | | | | | |
| Electric distribution | \$ 5,057 | \$ 4,776 | \$ (281) | \$ 693 15.9 % | \$ 411 9.4 % |
| Gas distribution | 2,136 | 2,020 | (116) | 174 8.9 % | 58 2.9 % |
| Electric generation | 2,327 | 2,297 | (30) | 136 6.2 % | 106 4.8 % |
| Total revenue requirements | \$ 9,520 | \$ 9,093 | \$ (427) | \$ 1,003 11.8 % | \$ 575 6.8 % |
| Cost Category: | | | | | |
| Operations and maintenance | \$ 2,143 | \$ 2,073 | \$ (70) | \$ 197 | \$ 128 |
| Customer services | 312 | 277 | (35) | (26) | (61) |
| Administrative and general | 1,316 | 1,203 | (113) | 363 | 250 |
| Less: Revenue credits | (196) | (194) | 2 | (43) | (42) |
| Franchise fees, taxes other than income, and other adjustments | 234 | 214 | (20) | 53 | 32 |
| Depreciation (including costs of asset removal), return, and income taxes | 5,711 | 5,520 | (191) | 459 | 268 |
| Total revenue requirements | \$ 9,520 | \$ 9,093 | \$ (427) | \$ 1,003 | \$ 575 |

For the Utility's largest requests in the GRC application (i.e., the CWSP and excess liability insurance costs), the settlement agreement includes the following terms:

- Funding of the Utility's CWSP forecast through a new two-way Wildfire Mitigation Balancing Account. This would include the costs associated with overhead system hardening and other incremental costs of wildfire mitigations that are approved by the CPUC. A reasonableness review threshold would apply if the Utility wishes to recover costs beyond 115% of the adopted forecast or average unit cost.
- Combination of routine and enhanced vegetation management costs in a new two-way Vegetation Management Balancing Account to track and record actual vegetation management costs (routine and enhanced) beyond the adopted level. A reasonableness review threshold would apply if the Utility wishes to recover beyond 120% of the adopted forecast. This new account would replace the currently established one-way Vegetation Management Balancing Account that covered costs for the routine program.
- A new two-way electric and gas Risk Transfer Balancing Account to record the difference between the amounts adopted for liability insurance premiums and the Utility's actual costs. This two-way account would allow the Utility to pass through actual insurance premium costs for up to \$1.4 billion in coverage. The Utility could also request additional coverage through an advice letter and/or pursue self-insurance.

Capital Additions and Rate Base

The settlement agreement assumes a 2020 weighted average rate base of approximately \$29.4 billion for the portions of the Utility's business reviewed in the GRC, compared with the Utility's original request of approximately \$29.9 billion. The \$0.5 billion difference is primarily due to the lower level of working capital, depreciation and other reductions in the settlement agreement. This rate base amount includes \$601 million of forecast capital spend in 2020 that will not earn an equity return, pursuant to AB 1054. For the purpose of the settlement agreement, the Utility calculated a weighted average rate base of \$31.0 billion and \$33.0 billion for 2021 and 2022, respectively. The Utility submitted its five-year financial forecast, including projected capital expenditure assumptions, in connection with its chapter 11 proceedings. While the Utility currently is evaluating capital expenditure assumptions, capital additions and rate base amounts may materially increase from the current forecast.

Over the 2020-2022 GRC period, the settlement agreement provides average annual capital investments of approximately \$4.6 billion in electric distribution, natural gas distribution and electric generation infrastructure. While the settlement agreement proposes overall revenue requirement increases for 2021 and 2022, it does not specify capital expenditures for those years.

Consistent with the Utility's GRC application, the settlement agreement does not propose funding for claims resulting from the 2017 Northern California wildfires or the 2018 Camp fire. Also, the Utility is not seeking recovery of compensation of PG&E Corporation's and the Utility's officers.

On December 2, 2019, the CPUC revised the procedural schedule for this proceeding.

Opening and reply briefs on disputed issues outside of the settlement agreement were submitted to the CPUC by several parties on January 6, 2020 and January 27, 2020, respectively. Opening and reply comments on the settlement agreement were submitted to the CPUC by several parties on January 21, 2020 and February 5, 2020, respectively.

As a result of the settlement and based on other facts and circumstances known to PG&E Corporation and the Utility as of the date of this filing, PG&E Corporation and the Utility expect to remain on track to satisfy the rate base conditions included in their exit financing documents.

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

In accordance with a January 16, 2020 CPUC decision in its OIR to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the GRC Plan the decision, the Utility is required to file with the CPUC on June 30, 2021 a single "general rate case" application requesting integrated GRC and GT&S related revenue requirements for test year 2023 and three attrition years.

2015 Gas Transmission and Storage Rate Case

In its final decisions in the Utility's 2015 GT&S rate case, the CPUC excluded from rate base \$696 million of capital spending in 2011 through 2014. This was the amount recorded in excess of the amount adopted in the 2011 GT&S rate case. The decision permanently disallowed \$120 million of that amount and ordered that the remaining \$576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The Utility would be required to take a charge in the future if the CPUC's audit of 2011 through 2014 capital spending resulted in additional permanent disallowance. The audit is still in process. The Utility cannot predict the timing and outcome of the audit.

As a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2015 GT&S rate case proposing to reduce revenue requirements by \$58 million and increase rate base by \$12 million for 2018 (excluding the impacts of an approximately \$7 million increase in revenue requirement and a \$60 million increase in rate base associated with the Utility's private letter ruling advice letter approved by the CPUC on July 18, 2018). On August 15, 2019, a final decision on the PFM was issued directing the Utility to consult with the CPUC's Energy Division to ensure that its calculations include the cost of removal component of book depreciation when calculating the amortization of protected excess deferred income taxes using the ARAM and to quantify the amount of unprotected excess deferred taxes, which can be returned to ratepayers without following the ARAM. In compliance with the decision, on September 13, 2019, the Utility filed an advice letter with the revised calculations and the length of time the revenue requirement reductions would be amortized in rates. On October 17, 2019, the CPUC approved the Utility's advice letter approving a revised computation of the effects of the Tax Act on the revenue requirements, resulting in a \$61 million reduction to the 2018 revenue requirement. The Utility incorporated the revenue requirement reduction into rates beginning January 1, 2020. The IRS is expected to provide additional guidance on ARAM. This IRS guidance may impact the Utility's calculation of the related revenue requirement. It is uncertain when the IRS guidance may be issued.

2019 Gas Transmission and Storage Rate Case

On September 12, 2019, the CPUC voted the final decision in the 2019 GT&S rate case of the Utility. By approving the decision, the CPUC adopted a 2019 revenue requirement of \$1.332 billion compared to the Utility's (revised) request of \$1.485 billion. This corresponds to an increase of \$31 million over the Utility's 2018 authorized revenue requirement of \$1.301 billion, compared to the \$184 million increase requested by the Utility. The CPUC also adopted revenue requirements of \$1.432 billion for 2020, \$1.516 billion for 2021, and \$1.580 billion for 2022, compared to the Utility's request of \$1.595 billion for 2020, \$1.693 billion for 2021, and \$1.679 billion for 2022.

The revenue requirement amounts requested by the Utility and the revenue requirement amounts in the decision are set forth in the following table:

| Revenue Requirement | 2018 | | | | |
|----------------------------|-----------------------------|-------------|-------------|-------------|-------------|
| (in millions) | Currently Authorized | 2019 | 2020 | 2021 | 2022 |
| Utility's Request | \$ 1,301 | \$ 1,485 | \$ 1,595 | \$ 1,693 | \$ 1,679 |
| Decision | \$ 1,301 | \$ 1,332 | \$ 1,432 | \$ 1,516 | \$ 1,580 |

The decision removed from rate base approximately \$304 million on a forecasted basis of pipeline replacement capital expenditures for the 2015-2018 period due to cost overruns; the Utility submitted updated recorded numbers to the CPUC that calculate the disallowance as \$237 million. Incorporating the forecast reduction, the decision adopted a rate base for 2019 of \$4.46 billion, which corresponds to an increase of \$0.75 billion over the 2018 adopted rate base of \$3.71 billion. This is compared to the Utility's rate base request of \$4.75 billion for 2019. The decision adopted a rate base of \$4.98 billion for 2020, \$5.37 billion for 2021, and \$5.71 billion for 2022.

The rate base amounts also exclude approximately \$576 million of capital spending subject to audit by the CPUC (related to 2011 through 2014 expenditures in excess of amounts adopted in the 2011 GT&S rate case), pursuant to the 2015 GT&S rate case decision. The Utility is unable to predict whether the \$576 million, or a portion thereof, will ultimately be approved by the CPUC and included in the Utility's future rate base.

The decision adopted capital expenditures of \$726 million for 2019, which corresponds to a decrease of \$104 million over the Utility's request of \$830 million. The decision adopted a post-test year ratemaking joint stipulation proposed by the Utility and PAO. The joint stipulation results in adopted capital expenditures of \$697 million in 2020, \$597 million in 2021, and \$570 million in 2022.

The decision adopted the Utility's proposed Natural Gas Storage Strategy, with minor modifications related to the decommissioning or sale of the Utility's Los Medanos and Pleasant Creek storage fields, and the decision adopted a two-way balancing account for storage costs, which will be subject to a reasonableness review in the next GT&S rate case. The decision retained a number of existing memorandum accounts and one-way balancing accounts, including a one-way expense balancing account for transmission integrity management, and adopted 19 new expense and capital one-way balancing and memorandum accounts.

The decision also resolved the second phase of this proceeding, addressing the removal of officer compensation costs from the revenue requirement, which is required by California Senate Bill 901. On this matter, the decision adopted the joint stipulation offered by the Utility, PAO and TURN that reduces the Utility's requested 2019 GT&S operating expenses by \$1.428 million and capital expenditures by \$0.455 million.

On October 23, 2019, the Utility filed an application with the CPUC requesting the rehearing of the final decision. Specifically, issues identified by the Utility include the adopted disallowance associated with vintage pipe replacement, reduction in the Utility's expense forecast for in-line inspections, and establishment of a memo account for Internal Corrosion Direct Assessment. The Utility cannot predict the timing and outcome of this matter.

On January 16, 2020, the CPUC approved a final decision in its OIR to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the GRC Plan, as a result of which the Utility will be required to combine the GRC and GT&S rate cases starting with the 2023 GRC and 2023 GT&S rate case. In accordance with the decision, on June 30, 2021, the Utility is required to file with the CPUC a single "general rate case" application requesting integrated GRC and GT&S related revenue requirements for test year 2023 and three attrition years.

Transmission Owner Rate Cases

Transmission Owner Rate Cases for 2015 and 2016 (the "TO16" and "TO17" rate cases, respectively)

On January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion granting an appeal of FERC's decisions in the TO16 and TO17 rate cases that had granted the Utility a 50 basis point ROE incentive adder for its continued participation in the CAISO. Those rate case decisions were remanded to FERC for further proceedings consistent with the Court of Appeals' opinion. On remand, FERC concluded that the Utility should no longer be authorized to receive the 50 basis point ROE incentive adder, the Utility would have incurred a refund obligation of \$1 million and \$8.5 million for TO16 and TO17, respectively. Alternatively, if FERC again concluded that the Utility should receive the 50 basis point ROE incentive adder and provided the additional explanation that the Ninth Circuit found the FERC's prior decisions lacked, then the Utility would not owe any refunds for this issue for TO16 or TO17.

On February 28, 2018, the Utility filed a motion to establish procedures on remand requesting additional briefing on the issues identified in the Ninth Circuit Court's opinion. On August 20, 2018, FERC issued an order granting the Utility's motion to allow for additional briefing. The order also consolidated the TO18 rate case with TO16 and TO17 for this issue. The Utility filed initial briefs on September 19, 2018 and reply briefs on October 10, 2018. On July 18, 2019, FERC issued its order on remand reaffirming its prior grant of the Utility's request for the 50 basis point ROE adder. On August 16, 2019, a number of parties filed for rehearing of that order. As a result, on September 16, 2019, FERC extended the amount of time it has to consider the request for rehearing by issuing a tolling order for the limited purpose of further consideration of the matters raised in the request.

Transmission Owner Rate Case for 2017 (the "TO18" rate case)

On July 29, 2016, the Utility filed its TO18 rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of \$1.72 billion, a \$387 million increase over the 2016 revenue requirement of \$1.33 billion. The forecasted network transmission rate base for 2017 was \$6.7 billion. The Utility sought a return on equity of 10.9%, which included an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted that it would make investments of \$1.30 billion in 2017 in various capital projects.

On September 30, 2016, the FERC issued an order accepting the Utility's July 2016 filing and setting it for hearing, but held the hearing procedures in abeyance for settlement procedures. The order set an effective date for rates of March 1, 2017 and made the rates subject to refund following resolution of the case. On March 17, 2017, the FERC issued an order terminating the settlement procedures due to an impasse in the settlement negotiations reported by the parties. During the hearings held in January 2018, the Utility, intervenors, and the FERC trial staff, addressed questions relating to return on equity, capital structure, depreciation rates, capital additions, rate base, operating and maintenance expense, administrative and general expense, and the allocation of common, general and intangible costs.

Additionally, on March 31, 2017, intervenors in the TO18 rate case filed a complaint at the FERC alleging that the Utility failed to justify its proposed rate increase in the TO18 rate case. On November 16, 2017, the FERC dismissed the complaint. On December 18, 2017, the complainants filed a request for a rehearing of that order, which the FERC denied on May 17, 2018.

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case proposing a ROE of 9.13% compared to the Utility's request of 10.90%, and an estimated composite depreciation rate of 2.96% compared to the Utility's request of 3.25%. The ALJ also rejected the Utility's method of allocating common plant between CPUC and FERC jurisdiction. In addition, the ALJ proposed to reduce forecasted capital and expense spending to actual costs incurred for the rate case period. Further, the ALJ proposed to remove certain items from the Utility's rate base and revenue requirement. The Utility and intervenors filed initial briefs on October 31, 2018, and reply briefs on November 20, 2018, in response to the ALJ's initial decision.

Once the FERC issues its decision, the Utility expects one or more parties to seek rehearing of that decision and then appeal it to the courts. The Utility is unable to predict the timing and outcome of this proceeding.

Transmission Owner Rate Case for 2018 (the "TO19" rate case)

On July 27, 2017, the Utility filed its TO19 rate case at the FERC requesting a 2018 retail electric transmission revenue requirement of \$1.79 billion, a \$74 million increase over the proposed 2017 revenue requirement of \$1.72 billion. The forecasted network transmission rate base for 2018 was \$6.9 billion. The Utility sought an ROE of 10.75%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted capital expenditures of approximately \$1.4 billion. On September 28, 2017, the FERC issued an order accepting the Utility's July 2017 filing, subject to hearing and refund, and established March 1, 2018 as the effective date for rate changes. The FERC also ordered that the hearings be held in abeyance pending settlement discussion among the parties. On May 14, 2018, the Utility filed a proposal to reflect the impact of the Tax Act on its TO tariff rates effective March 1, 2018, in the resolution of the TO19 rate case. The tax impact reduces the TO19 requested revenue requirement from \$1.79 billion to \$1.66 billion.

On September 29, 2017, intervenors in the TO19 rate case filed a complaint at the FERC alleging that the Utility failed to justify its proposed rate increase in the TO19 rate case. On October 17, 2017, the Utility requested that the FERC dismiss the complaint. On May 17, 2018, the FERC issued an order setting the complaint for hearing, initiating settlement judge procedures, and consolidating the complaint with the TO19 proceeding.

On September 21, 2018, the Utility filed an all-party settlement with the FERC in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined upon the issuance of a final, non-appealable TO18 decision. Additionally, if the FERC were to determine that the Utility was not entitled to the 50 basis point incentive adder for the Utility's continued CAISO participation, then the Utility would be obligated to make a refund to customers of approximately \$25 million. On December 20, 2018, the FERC issued an order approving the all-party settlement. Additionally, on July 18, 2019, the FERC issued an order on remand reaffirming its grant of the Utility's request for the 50 basis point incentive adder for continued CAISO participation. On September 30, 2019, the FERC issued an order on rehearing that denied a pending request for rehearing of the FERC's decision granting the 50 basis point ROE adder in the TO19 proceeding.

Transmission Owner Rate Case for 2019 (the "TO20" rate case)

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

The formula rate replaces the "stated rate" methodology that the Utility used in its previous TO rate case filings. The formula rate methodology still includes an authorized revenue requirement and rate base for a given year, but it also provides for an annual update of the following year's revenue requirement and rates in accordance with the terms of the FERC-approved formula. Under the formula rate mechanism, transmission revenue requirements will be updated to the actual cost of service annually as part of the true-up process. Differences between amounts collected and determined under the formula rate will be either collected from or refunded to customers.

In the filing, the Utility forecasts a 2019 retail electric transmission revenue requirement of \$1.96 billion. The proposed amount reflects an approximately 9.5% increase over the as-filed TO19 requested revenue requirement of \$1.79 billion (a subsequent reduction to \$1.66 billion was identified as a result of the Tax Act). The Utility forecasts that it will make investments of approximately \$1.1 billion and \$0.7 billion for 2018 and 2019, respectively, for various capital projects to be placed in service before the end of 2019. Including projects to be placed in service beyond 2019, the Utility forecasts total electric transmission capital expenditures of \$1.4 billion in 2018 and \$1.4 billion in 2019. The Utility's forecasted rate base for 2019 is approximately \$8 billion on a weighted average basis, compared to the Utility's forecasted rate base of \$6.9 billion in 2018. The Utility has requested that FERC approve a 12.5% return on equity (which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO), an increase from the 10.75% (also inclusive of a 50 basis point CAISO incentive adder) requested in its TO19 rate case.

On May 9, 2019, the Utility filed an application with the FERC requesting revisions to its TO20 rate case formula rate model to remove the impact of the non-cash wildfire-related charges on the ratio of common equity to total capital. The Utility indicates in its application that, because of the recording of the non-cash wildfire-related charges in connection with the 2017 Northern California wildfires and the 2018 Camp fire, the Utility's financial statements reflected a ratio of common equity to total capital of approximately 41% as of December 31, 2018. The Utility indicates that the proposed revisions adjust the equity ratio to accurately reflect how the Utility financed the capital projects that are included in rate base. The Utility's current rate base was financed with an equity ratio of approximately 52%, rather than the 41% equity ratio. In addition, on May 9, 2019, the Utility submitted a request to the FERC to exclude the wildfire charge from the Utility's capital structure for the purpose of calculating its allowance for funds used during construction effective January 1, 2019.

On July 10, 2019, the FERC accepted the Utility's revisions to the formula rate to become effective December 9, 2019, subject to refund, established hearing and settlement judge procedures, and reflected it with the Utility's TO20 case.

On November 27, 2019, the Utility filed its annual update filing under the TO20 Formula Rate for the rate year 2020 for the rates that will be effective January 1 through December 31, 2020, subject to refund and true-up.

The parties conducted several settlement conferences throughout 2019 and currently expect to file a partial settlement with the FERC no later than March 31, 2020.

Nuclear Decommissioning Cost Triennial Proceeding

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as 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.

On December 13, 2018, the Utility submitted its 2018 NDCTP application, which includes a Diablo Canyon site-specific decommissioning cost estimate of \$4.8 billion to decommission the Diablo Canyon facilities.

On February 14, 2019, the CPUC issued a scoping memo addressing the scope of the Utility's 2018 NDCTP application to include the reasonableness of the Diablo Canyon decommissioning cost estimate, ratemaking proposals, proposed Diablo Canyon milestone framework, plans to address host community needs, reasonableness of Humboldt Bay Power Plant decommissioning costs, and reasonableness of performing Diablo Canyon planning activities pre-shutdown, including the proposed rate of recovery of these pre-planning activities addressed in the Utility's application for authorization to establish the Diablo Canyon decommissioning planning memorandum account (the "Diablo Canyon DPM account application").

On March 7, 2019, the CPUC amended the scoping memo to combine the Diablo Canyon DPM account application, which seeks authorization for the Utility to establish the Diablo Canyon Decommissioning Memorandum Account to track funding for Diablo Canyon pre-shutdown decommissioning planning activities, with the 2018 NDCTP. The CPUC approved the Utility to establish an interim mechanism to track decommissioning planning activity expenses in the Diablo Canyon Decommissioning Memorandum Account. Any Memorandum Account recovery of such expenses is subject to the authorization and approval of the CPUC, which will be discussed in this year's NDCTP. The assigned ALJ deferred the decision of cost recovery until after the NRC addresses the Utility's December 13, 2018 exemption request, in which the Utility requested an exemption to allow the Utility to withdraw from the NDT to fund decommissioning planning activities. The CPUC held public participation hearings on August 7 and 8, 2019 for residents and organizations in and near San Luis Obispo in connection with the Utility's request.

On September 10, 2019, the NRC issued a letter granting the Utility's request for an exemption and authorizing the Utility to access the NDT for up to \$187.8 million on decommissioning planning activities. On October 4, 2019, the Utility submitted supplemental testimony to the NRC addressing how it proposes to modify its request in light of the NRC exemption and the Utility's proposed disposition of and ratemaking treatment of the planned Baywood Feed, a 12-kilovolt transmission line.

On October 24, 2019, the Utility and TURN requested a suspension of the procedural schedule in order to allow parties to continue settlement discussions. On January 10, 2020, the settlement agreement that the parties had reached was filed with the CPUC, along with a joint motion for adoption of settlement agreement.

Under the proposed settlement agreement, the Utility would collect annual revenue requirements of \$112.5 million and \$3.9 million over for the funding of the Diablo Canyon tax qualified trust and Humboldt Bay tax qualified trust, respectively, commencing January 1, 2020. Additionally, under the proposed settlement agreement, the \$398.4 million spent for Humboldt Bay Power Plant decommissioning project costs completed to date would be deemed reasonable.

The Utility is unable to determine the timing and outcome of this proceeding.

Petition for Modification of CPUC Decision Approving Retirement of Diablo Canyon Power Plant

On June 20, 2016, the Utility entered into a joint proposal with certain parties, including the Alliance for Nuclear Responsibility, to retire Diablo Canyon's two nuclear power reactor units at the expiration of their current operating licenses in 2024 and 2025. On January 11, 2018, the CPUC approved the planned retirement by 2024 and 2025, but required legislative authorization for certain key aspects of the joint proposal. On November 29, 2018, in response to SB 1090, the CPUC issued a further decision addressing the key remaining goals of the Diablo Canyon joint proposal agreement.

On October 1, 2019, the Alliance for Nuclear Responsibility filed a PFM of the CPUC's January 11, 2018 decision approving the planned retirement of Diablo Canyon. The PFM argues that above-market costs attributable to Diablo Canyon under the Power Charge Indifference Adjustment methodology, when combined with decreasing bundled load by the Utility, create material changed circumstances that undermine the reasonableness of incurring costs to operate Diablo Canyon until its retirement. On October 31, 2019, the Utility filed a joint response with Friends of the Earth, Natural Resources Defense Council, CUE, and IBEW Local 1245, which argued that modification of the CPUC's initial decision is not warranted and is not in the public interest. On February 7, 2020, the ALJ issued a PD denying the Alliance for Nuclear Responsibility's PFM. The CPUC decision on the PD is anticipated no later than March 2020.

Wildfire Expense Memorandum Account

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. In the WEMA, the Utility can record costs related to wildfires, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expenses paid by the Utility but excluding costs that have already been forecasted and adopted in the Utility's GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) insurance premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, or through FERC authorized rates, will be credited to the WEMA as they are received. The WEMA will not include the Utility's costs for fire response and infrastructure costs, which are tracked in the CEMA. 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. (See Notes 4 and 14 of the Notes to the Consolidated Financial Statements in Item 8.)

As of December 31, 2019, the Consolidated Financial Statements include long-term regulatory assets, consisting of insurance premium costs that are probable of recovery (see "Long-Term Regulatory Assets" in Note 4 of the Notes to the Consolidated Financial Statements in Item 1). Should PG&E Corporation and the Utility conclude in future periods that recovery of insurance premiums in excess of amounts included in authorized revenue requirements is no longer probable, PG&E Corporation and the Utility will record a charge in the period such conclusion is reached.

Catastrophic Event Memorandum Account Applications

The CPUC allows utilities to recover the reasonable, incremental costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities through a CEMA. In 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. The costs associated with this work are tracked in the CEMA. The Utility's CEMA applications are subject to CPUC review and approval. For more information see Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

2019 CEMA Application

On September 13, 2019, the Utility submitted to the CPUC its 2019 CEMA application requesting cost recovery of \$159.3 million in connection with thirteen catastrophic events that included twelve wildfires and one storm for declared emergencies from mid-2017 through 2018. The 2019 CEMA application does not include costs related to the 2015 Butte fire, the 2017 Northern California wildfires, or the 2018 Camp fire. A prehearing conference was held on November 4, 2019 and a scoping memo was issued on December 6, 2019.

PG&E Corporation and the Utility are unable to predict the timing and outcome of this overall proceeding.

2018 CEMA Application

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of \$183 million in connection with seven catastrophic events that included fire and storm declared emergencies from mid-2016 through early 2017, as well as \$405 million related to work performed in 2016 and 2017 to cut back or remove dead or dying trees that were exposed to years of drought conditions and bark beetle infestation. The 2018 CEMA application originally sought cost recovery of \$555 million on a forecast basis, for additional tree mortality and fire risk mitigation work anticipated in 2018 and 2019, subject to true-up if actual costs were greater or less than the forecast. However, on April 25, 2019, the CPUC adopted a decision denying cost recovery on a forecast basis for the 2018 and 2019 costs requested.

On April 25, 2019, the CPUC approved the Utility's request for interim rate relief, allowing for recovery of \$373 million of costs (63% of the total costs incurred in 2016 and 2017), compared to \$588 million requested by the Utility. The interim rate relief was implemented on October 1, 2019. Costs included in the interim rate relief are subject to audit and refund. On August 7, 2019, the Utility filed a Revised Application, Revised Testimony and Revised Workpapers, reflecting a new revenue requirement request of \$669 million, pursuant to CPUC ruling allowing these changes. The \$669 million incorporates (i) the removal of forecast tree mortality costs (reduction of approximately \$555 million); (ii) inclusion of the 2018 Tree Mortality and Fire Risk Reduction activities (increase of approximately \$90 million); and (iii) other corrections and updates found since the filing (reduction of approximately \$9 million), as compared to the Utility's original request of \$1.14 billion.

The 2018 CEMA application does not include costs related to the 2015 Butte fire, the 2017 Northern California wildfires, or the 2018 Camp fire.

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

Fire Hazard Prevention Memorandum Account

The CPUC allows utilities to track and record costs associated with implementing 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. The Utility tracked such costs in the FHPMA through the end of 2019.

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 the OII into the 2017 Northern California Wildfires and the 2018 Camp Fire. Pursuant to the settlement agreement, the Utility agrees, among other things, to not seek recovery of \$36 million of wildfire-related expenses recorded in the FHPMA. For more information on the settlement agreement, see Note 15 of the Notes to the Consolidated Financial Statements.

Other than the amounts subject to the settlement agreement in connection with the OII into the 2017 Northern California Wildfires and the 2018 Camp Fire, the Utility believes such costs are recoverable but rate recovery requires CPUC reasonableness review and authorization in a separate proceeding or through a GRC.

For the amount recorded to this memorandum account as of December 31, 2019, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

Fire Risk Mitigation Memorandum Account

On March 12, 2019, the CPUC approved the Utility's FRMMA to track costs incurred beginning January 1, 2019, for fire risk mitigation activities that are not otherwise covered in revenue requirements. The FRMMA was authorized by SB 901 and AB 1054 to capture mitigation costs of activities not included in a CPUC approved Wildfire Mitigation Plan. The Utility has proposed that the FRMMA continue after the approval of its 2019 Wildfire Mitigation Plan to record costs of wildfire mitigation activities that were beyond the initial identified scope of work.

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 the OII into the 2017 Northern California Wildfires and the 2018 Camp Fire. Pursuant to the settlement agreement, the Utility agrees, among other things, to not seek recovery of \$236 million of wildfire-related expenses recorded in the FRMMA and the WMPMA. For more information on the settlement agreement, see Note 15 of the Notes to the Consolidated Financial Statements.

Other than the amounts subject to the settlement agreement in connection with the OII into the 2017 Northern California Wildfires and the 2018 Camp Fire, the Utility intends to seek recovery of the FRMMA balance in a future application, which rate recovery requires CPUC reasonableness review and authorization in a separate proceeding or through a GRC. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs in connection with the 2019 Wildfire Mitigation Plan recorded in the FRMMA, which the Utility expects will be substantial.

For the amount recorded to this memorandum account as of December 31, 2019, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

Wildfire Mitigation Plan Memorandum Account

On June 5, 2019, the Utility submitted an advice letter to establish the WMPMA (also called the Wildfire Plan Memorandum Account) effective May 30, 2019. The purpose of the WMPMA is to track costs incurred to implement the Utility's Wildfire Mitigation Plan, as required by Public Utilities Code Sections 8386 et seq, as modified by SB 901 and subsequent bills including AB 1054, AB 111, SB 70, SB 167, SB 247, and SB 560. The WMPMA is required to be established upon approval of a utility's wildfire mitigation plan to track costs incurred to implement the plan. The CPUC approved the memorandum account on August 5, 2019, so the Utility will record any costs incurred in implementing an approved Wildfire Mitigation Plan as of the effective date, June 5, 2019.

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 the OII into the 2017 Northern California Wildfires and the 2018 Camp Fire. Pursuant to the settlement agreement, the Utility agrees, among other things, to not seek recovery of \$236 million of wildfire-related expenses recorded in the FRMMA and the WMPMA. For more information on the settlement agreement, see Note 15 of the Notes to the Consolidated Financial Statements.

Other than the amounts subject to the settlement agreement in connection with the OII into the 2017 Northern California Wildfires and the 2018 Camp Fire, the Utility anticipates that the recovery of the costs recorded to the WMPMA would occur through a general rate case or future application at which time the CPUC would review the costs for reasonableness as required by SB 901. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs in connection with the 2019 Wildfire Mitigation Plan recorded in the WMPMA, which the Utility expects will be substantial.

For the amount recorded to this memorandum account as of December 31, 2019, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

Other Regulatory Proceedings

2019 Wildfire Mitigation Plan

On October 25, 2018, the CPUC opened an OIR to implement the provisions of SB 901 related to electric utility wildfire mitigation plans. This OIR provided guidance on the form and content of the initial wildfire mitigation plans, provided a venue for review of the initial plans, and developed and refined the content of and process for review and implementation of wildfire mitigation plans to be filed in future years. In this proceeding the CPUC determined, among other things, how to interpret and apply SB 901's list of required plan elements, as well as what additional elements beyond those required in SB 901 should be included in the wildfire mitigation plans. SB 901 also requires, among other things, that such plans include a description of the preventive strategies and programs to be adopted by an electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including the consideration of dynamic climate change risks, plans for vegetation management, and plans for inspections of the electrical corporation's electrical infrastructure. The scope of this proceeding does not include utility recovery of costs related to wildfire mitigation plans, which SB 901 requires to be addressed in separate rate recovery applications.

On February 6, 2019, the Utility filed its wildfire mitigation plan (the "2019 Wildfire Mitigation Plan") with the CPUC. The 2019 Wildfire Mitigation Plan describes forecasted work and investments in 2019 that are designed to help further reduce the potential for wildfire ignitions associated with the Utility's electrical equipment in high fire-threat areas. The 2019 Wildfire Mitigation Plan includes measures the Utility proposed to take in 2019 and longer-term plans, subject to further modifications, as follows:

- installing approximately 600 new, high-definition cameras, made available to Cal Fire and local fire officials, in high fire-threat areas by 2022, increasing coverage across high fire-threat areas to more than 90%;
- adding approximately 1,300 additional new weather stations by 2022, at a density of one station roughly every 20 circuit miles in high fire-threat areas;
- conducting enhanced safety inspections of electric infrastructure in high-fire threat areas, including approximately 735,000 electric towers and poles across approximately 5,700 transmission line miles and 25,200 distribution line miles;
- further enhancing vegetation management efforts across high and extreme fire-threat areas to address vegetation that poses higher potential for wildfire risk, such as removing or trimming trees from particular "at-risk" tree species that have exhibited a higher pattern of failing;
- continuing to disable automatic reclosing in high fire-threat areas during wildfire season and periods of high fire-risk and upgrading reclosers and circuit breakers in high fire-threat areas with remote control capabilities;
- expanding the PSPS to include all transmission and distribution lines in Tier 2 and Tier 3 High Fire-Threat District areas;
- installing stronger and more resilient poles and covered power lines, including targeted undergrounding, starting in areas with the highest fire risk, ultimately upgrading and strengthening approximately 7,100 miles over the next 10 years; and
- partnering with additional communities in high fire-threat areas to create new resilience zones that can power central community resources during a PSPS.

On February 12, February 14, and April 25, 2019, the Utility filed amendments to the 2019 Wildfire Mitigation Plan with the CPUC to correct inadvertent errors in the cost table attached to the 2019 Wildfire Mitigation Plan; refine language in the 2019 Wildfire Mitigation Plan; and modify certain 2019 Wildfire Mitigation Plan targets.

On May 30, 2019, the CPUC adopted a decision that generally approved the Utility's 2019 Wildfire Mitigation plan as amended February 14, 2019, subject to certain reporting, data gathering, and other requirements set forth in the decision. Also, on May 30, 2019, the Utility adopted another decision regarding California IOUs wildfire mitigation plans, that among other things, includes additional reporting, data gathering, and other requirements.

On June 14, 2019, the assigned commissioner and ALJ issued a decision implementing Phase 2 of the OIR, announcing Phase 2 workshops. The decision also announced that the CPUC would evaluate the Utility's April 25th amendment in Phase 2, as well as the process for independent evaluation of the Utility's compliance with its 2019 plan.

On August 23, 2019, the CPUC approved the Utility's Initial Safety Certification, which under AB 1054 entitles the Utility to certain benefits, including eligibility for a cap on wildfire fund reimbursement and for a reformed prudent manager standard. The Utility satisfied the required elements for its Initial Safety Certificate, as follows: (i) the electrical corporation has an approved wildfire mitigation plan, (ii) the electrical corporation is in good standing, which can be satisfied by the electrical corporation having agreed to implement the findings of its most recent safety culture assessment, if applicable, (iii) the electrical corporation has established a safety committee of its board of directors composed of members with relevant safety experience, and (iv) the electrical corporation has established board-of-director-level reporting to the CPUC on safety issues. The Initial Safety Certification is valid for twelve months.

On September 18, 2019, the CPUC issued a scoping memo and ruling for Phase 2 setting the scope and procedural schedule. On December 16, 2019, the CPUC issued a ruling proposing WMP templates and evaluative materials on which the CPUC would rely for 2020 wildfire mitigation plans. These included WMP Guidelines, a maturity model, a utility survey, WMP metrics, and a supplemental data request. The utilities are required to complete the WMP Guidelines and the utility survey when submitting the 2020 WMP. Since December 16, 2019, the CPUC has held a number of workshops and issued clarifications of the December 16, 2019 materials.

On February 5, 2020, the assigned ALJ issued a PD in Phase 2 of this proceeding on electrical corporations' wildfire mitigation plans. It resolves one Phase 2 issue by requiring all electrical corporations to conduct outreach to communities and the public before, during, and after a wildfire. If adopted, the PD would clarify among other things where the additional Phase 2 issues will be resolved: the CPUC's newly created Wildfire Safety Division would review 2020 wildfire mitigation plans, present resolutions for CPUC consideration on the 2020 Plans, and oversee independent evaluation and other compliance activity with regard to both 2019 and 2020 Plans. Opening and reply comments are due on February 25, 2020 and March 2, 2020, respectively. The CPUC decision on the PD is expected no later than March 2020.

2020-2022 Wildfire Mitigation Plan

On February 7, 2020, the Utility publicly posted its 2020 Wildfire Mitigation Plan and utility survey. The Utility's 2020 Wildfire Mitigation Plan describes the Utility's wildfire safety programs, which are focused on three key areas: reducing the potential for fires to be started by electrical equipment, reducing the potential for fires to spread, and minimizing the frequency, scope and duration of Public Safety Power Shut-off events, as well as providing historical data requested by the guidelines. The primary programs include continuing enhanced vegetation management, system hardening, system automation, the wildfire safety operations center, installing additional situational awareness tools, and public safety power shutoffs, as well as working to reduce the frequency, scope, and duration of public safety power shutoffs. The Utility plans to conduct enhanced vegetation management on approximately 1,800 miles of lines for 2020 and beyond based on insights gained from the 2019 effort. The Utility is also incorporating the enhanced inspection process and tools from the 2019 wildfire safety inspection program into the routine inspection and maintenance program. For 2020, the Utility plans the following improvements: hardening 241 line-miles for a total of 7,100 line miles over 12 to 14 years; sectionalizing 592 devices; making PSPS events fewer, smaller and shorter; installing 400 weather stations and 200 cameras; and operating additional microgrids during PSPS events. The utility survey will be used to collect information relevant to track the utility's capabilities in reducing wildfire risk and corresponding maturity levels over time. Along with other inputs, responses to the survey will establish a baseline maturity in 2020 and a target maturity for 2023.

PG&E Corporation and the Utility expect the CPUC to issue a decision on its 2020-2022 WMP by June 2020. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected if the Utility is unable to timely recover costs in connection with the 2019 Wildfire Mitigation Plan, and the 2020-2022 Wildfire Mitigation Plan recorded in the FRMMA and WMPMA, which the Utility expects will be substantial.

OIR Regarding Microgrids

On September 19, 2019, the CPUC initiated a rulemaking proceeding to examine microgrid implementation issues and resiliency strategies pursuant to SB 1339. In the first track of that proceeding, the CPUC is seeking to deploy resiliency planning in areas that are prone to outage events and wildfires, with the stated goal of putting some microgrid and other resiliency strategies in place by Spring or Summer 2020, if not sooner. A decision giving direction for mitigation measures ready for implementation by September 1, 2020 is expected in Spring 2020. At the CPUC's direction, the Utility submitted a proposal for immediate implementation of resiliency strategies on January 21, 2020. The Utility's proposal contains three components for which it is seeking scope and cost recovery authorization of up to approximately \$379 million in both expense and capital. These include:

- a make-ready program to invest in the infrastructure needed to allow high-priority substations and associated downstream infrastructure to operate as microgrids through the use of distributed generation ("DG"). The Utility is also conducting a Request for Offers for permanent DG to serve these substations and plans to file for cost recovery and approval of any executed contracts for permanent generation through a separate CPUC proceeding;
- a temporary generation program to provide mobile, temporarily-sited DG at substations, mid-feeder line segments serving commercial corridors and critical facilities, and single-customer critical facilities during PSPS events; and
- a community microgrid enablement program to provide incremental technical and financial support on a prioritized basis for community-requested microgrids for PSPS shutoff mitigation purposes.

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

OIR Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901

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.

OII to Consider PG&E Corporation's and the Utility's Proposed Plan of Reorganization

On October 4, 2019, the CPUC issued an OII to consider the ratemaking and other implications "that will result from the confirmation of a plan of reorganization and other regulatory approvals necessary to resolve" the Chapter 11 Cases (the "Chapter 11 Proceedings OII"). The Chapter 11 Proceedings OII indicates that the proceeding will "afford parties the opportunity to be heard and comment on" any CPUC "regulatory review resulting from a proposed plan of reorganization (including any amendments) filed with the Commission, any proposed settlement agreement resolving [the Chapter 11 Cases] between PG&E and Commission staff filed in connection with a plan, any regulatory approvals required pursuant to Public Utilities Code Section 3292 in order for PG&E to become eligible to participate in the wildfire fund established pursuant to Assembly Bill 1054 (AB) 1054, any other regulatory approvals required by AB 1054, and any other matters that may need to be decided by [the CPUC] in connection with a plan." The OII anticipates that the proceeding "will serve as a venue for review of a proposed plan and all attendant issues identified as within the scope of this proceeding." The CPUC "expects to render its decision sufficiently in advance of the June 30, 2020 statutory deadline contained in AB 1054 to allow the Bankruptcy Court to address and approve any modifications made to the plan pursuant to Commission orders."

On November 14, 2019, the assigned commissioner issued a scoping memo which divided the proceeding into two phases, first addressing non-financial issues (which include safety governance, climate goals, procurement, and other non-financial issues) and then financial issues (which include ratemaking, fines and penalties, financial governance, and other financial issues). After holding a status conference on December 20, 2019, the ALJ issued a ruling on December 27, 2019 modifying the schedule. That ruling re-combined the two phases of the proceeding such that financial and non-financial issues will be considered together. On January 16, 2020, the Utility filed a motion to further modify the schedule, which the ALJ granted in part. Pursuant to that modified schedule, on January 31, 2020, the Utility submitted testimony to the CPUC. The Utility's testimony outlined key elements of the company's updated Chapter 11 plan of reorganization, including, but not limited to, key aspects of the Utility's governance structure; implementing a plan to regionalize the company's operations; appointing an independent safety advisor; strengthening the roles of the Chief Risk Officer and the Chief Safety Officer; utilizing an Independent Safety Oversight Committee with non-PG&E Corporation and non-Utility employees to provide independent review of the company's operations; paying value in excess of \$25.5 billion to wildfire victims through the settlements reached; and emerging with a financing structure that seeks to protect customer rates and position the company for long term success. Reply testimony was due February 14, 2020, evidentiary hearings are scheduled for February 19-28, 2020, and post-hearing briefing is scheduled for March 2020.

On January 22, 2020, the Utility entered into a RSA with members of the Ad Hoc Committee of Senior Unsecured Noteholders of the Utility and, consistent with that agreement, on January 23, 2020, the Ad Hoc Committee of Senior Unsecured Noteholders of the Utility filed a motion to withdraw from the proceeding. On January 30, 2020, the ALJ issued a ruling allowing the Ad Hoc Committee of Senior Unsecured Noteholders to withdraw as a party.

Wildfire Fund Non-Bypassable Charge

In response to directives in AB 1054, on July 26, 2019, the CPUC opened a new rulemaking to consider the authorization of a non-bypassable charge to support the Wildfire Fund. On October 24, 2019, the CPUC issued a final decision finding that the imposition of the non-bypassable charge is just and reasonable. In addition, the decision affirmed that the Utility and its customers will not pay an allocated share of the adopted wildfire charge revenue requirement unless and until the Utility participates in the Wildfire Fund. The decision also continues the same allocation of the wildfire charge revenue requirement among the investor-owned utilities as previously adopted for the Department of Water Resources power and bond charge revenue requirements. The decision proposes revenue requirements for the Utility of \$404.6 million, which is based on average annual collections and shall expire at the end of the year 2035.

On November 25, 2019, an individual intervenor filed an application for rehearing of the decision arguing that the decision constitutes a constitutional violation of procedural due process and an unjust and unreasonable rate increase. On December 10, 2019, the Utility, along with San Diego Gas and Electric Company and Southern California Edison Company argued that due process rights were not violated and the CPUC appropriately determined the non-bypassable charge is just and reasonable.

Transportation Electrification

SB 350 requires the CPUC, in consultation with the California Air Resources Board and the CEC, to direct electrical corporations to file applications for programs and investments to accelerate widespread TE. In September 2016, the CPUC directed the Utility and the other large IOUs to file TE applications that include both short-term projects (of up to \$20 million in total) and two-to-five year programs with a requested revenue requirement determined by the Utility.

On May 31, 2018, the CPUC issued a final decision approving the Utility's two-to-five year program proposals for actual expenditures up to approximately \$269 million (including \$198 million of capital expenditures), to support utility-owned make-ready infrastructure supporting public fast charging and medium to heavy-duty fleets. In the EV Fleet program, the Utility has a goal of providing make-ready infrastructure at 700 sites supporting 6,500 vehicles, conducting operation and maintenance of installed infrastructure, and educating customers on the benefits of electric vehicles. The final decision gives customers the option of self-funding, installing, owning, and maintaining the make-ready infrastructure installed beyond the customer meter in lieu of utility ownership, after which they would receive a utility rebate for a portion of those costs. The EV Fast Charge program has a goal to install utility-owned make-ready infrastructure at approximately 52 public charging sites amounting to roughly 234 DC fast chargers.

On December 19, 2018, the CPUC initiated a new Rulemaking for vehicle electrification matters (R.18-12-006). This new proceeding will include issues related to utility rate designs supporting transportation electrification and hydrogen fueling stations, a framework for IOUs' transportation electrification investments, and vehicle-grid integration. A prehearing conference for this rulemaking was held on March 1, 2019. On May 2, 2019, the assigned commissioner issued a scoping memo and ruling for the proceeding, which sets forth the category, issues to be addressed, and schedule of the proceeding.

Electric Distribution Resources Plan

As required by California law, on July 1, 2015, the Utility filed its proposed electric DRP for approval by the CPUC. The Utility's DRP identifies its approach for identifying optimal locations on its electric distribution system for deployment of DERs. The Utility's DRP approach is designed to allow distributed energy technologies to be integrated into the larger grid, while continuing to provide customers with safe, reliable, and affordable electric service.

On June 1, 2018 and on September 4, 2018, the Utility filed with the CPUC its first annual distribution grid needs assessment report and its first distribution deferral opportunity report, respectively. On February 5, 2019, the CPUC approved the Utility's proposal to competitively procure distribution services from third-party owned DERs to defer selected distribution projects as identified in the Utility's first annual distribution deferral report. On December 2, 2019, the Utility filed for approval of three executed DER contracts related to two deferral opportunities. The Utility's second annual distribution grid assessment, and distribution deferral opportunity report, were filed on August 15, 2019. On December 16, 2019, the CPUC approved the Utility's proposal to competitively procure distribution services from third-party owned DERs to defer selected distribution projects as identified in the Utility's second annual distribution deferral opportunity report.

On March 26, 2018, the CPUC issued a final decision requiring the Utility to include a grid modernization plan for integrating DERs in the Utility's GRC. On December 13, 2018, the Utility filed its 2020 GRC Application, which includes the Utility's grid modernization plan.

OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas Planning

On January 16, 2020, the CPUC opened an OIR to address reliability and compliance standards for gas public utilities and impacts due to legislative mandates to address the greenhouse gas reduction emissions which will result in the replacement of gas-fuel technologies and reduced demand for natural gas. This proceeding will examine whether recent industry related events will require the CPUC to change the rules, processes and regulations governing gas utilities, including but not limited to, gas reliability standards, long-term contracting, regulatory accounting, reporting and tariff changes for operational flow orders.

This proceeding is expected to have three phases: Track 1A - System Reliability Standards, Track 1B - Market Structure and Regulations and Track 2 - Long Term Natural Gas Policy and Planning. Additionally, in Track 2, the CPUC will examine to what extent the projected gas demand reduction will require regulatory changes, such as shortening the useful life of gas assets, to ensure gas transmission costs are fairly allocated and that stranded costs are mitigated. The CPUC expects to issue a preliminary scoping memo and decision for each track.

Tracks 1A and 1B are expected to be completed within 18 months. Track 2 is expected to be resolved within 31 months in order to resolve issues to be considered in Track 1A and 1B and coordinate with other regulatory proceedings. This proceeding has been preliminarily designated as quasi-legislative. Evidentiary hearings may be necessary for Track 1A and Track 2. The Utility may file and serve opening comments on the preliminary scope no later than February 26, 2020 and reply comments on March 12, 2020.

OIR to Consider Strategies and Guidance for Climate Change Adaptation

On April 26, 2018, the CPUC opened an OIR to consider strategies for integrating climate change adaptation matters into relevant CPUC proceedings. On October 10, 2018, the CPUC issued a scoping memo, establishing two phases for this proceeding, and determined a procedural schedule. Scope of phase one covers five topics regarding how to integrate climate change adaptation into the IOUs' existing planning and operations to avoid or mitigate projected utility safety and reliability vulnerability to forecasted climate change impacts. Phase 2 will be scoped at a later time, but it is not expected to apply to the Utility. On October 24, 2019, the CPUC adopted a final decision extending the statutory deadline of this proceeding to September 30, 2020.

On October 24, 2019, the CPUC adopted a final decision on a portion of phase one (Topic 1 and 2), defining climate change adaptation for California's energy utilities as "adjustment in natural and human systems to a new or changing environment. Adaptation to climate change for energy utilities regulated by the CPUC refers to adjustment in utility systems using strategic and data-driven consideration of actual or expected climatic impacts and stimuli or their effects on utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable and resilient operations." In addition, this decision provides guidance on what data should be used by the investor-owned utilities to perform all climate impact, climate risk, and climate vulnerability analyses undertaken with respect to their infrastructure assets, operations, and customer impacts. Finally, this decision requires the energy utilities to adhere to the same climate scenarios and projections used in the most recent California Statewide Climate Change Assessment when analyzing climate impacts, climate risk, and climate vulnerability of utility systems, operations, and customers.

The remaining topics in phase one of this proceeding are still under consideration and will be subject to a separate decision. Those issues include: guidance on how climate adaptation should be incorporated into the investor-owned utilities' investment plans, program design, and operations; how climate change might affect vulnerable and disadvantaged communities; and into which specific CPUC proceedings and activities climate adaptation should be incorporated, including development of specific procedures. The CPUC decision on such issues is anticipated no earlier than mid-2020.

OIR to Examine Utility De-energization of Power Lines in Dangerous Conditions

On December 13, 2018, the CPUC opened an OIR to examine the notification, mitigation, and reporting requirements on electric utilities when de-energizing power lines in case of dangerous conditions that threaten life or property in California. This proceeding has focused on the following issues:

- examining conditions in which proactive and planned de-energization is practiced;
- developing best practices and ensuring an orderly and effective set of criteria for evaluating de-energization programs;

- ensuring electric utilities coordinate with state and local level first responders, and align their systems with the Standardized Emergency Management System framework;
- mitigating the impact of de-energization on vulnerable populations;
- examining whether there are ways to reduce the need for de-energization;
- ensuring effective notice to affected stakeholders of possible de-energization and follow-up notice of actual de-energization; and
- ensuring consistency in notice and reporting of de-energization events.

On May 30, 2019, the CPUC approved a decision for phase one of this proceeding, which adopted de-energization communication and notification guidelines for the electric IOUs along with updates to requirements established in Resolution ESRB-8. The CPUC also provided clarity on phase two issues; however, a final determination of phase two issues will be conveyed in the phase two scoping memo. Phase two will take a more comprehensive look at de-energization practices, including mitigation, additional coordination across agencies, further refinements to findings in phase one, re-energization practices, and other matters.

On August 14, 2019, the former CPUC president issued a phase two scoping memo. However, subsequent to the October PSPS events, on November 1, 2019, the ALJ issued a ruling suspending the schedule and scope of the proceeding and indicating that the current CPUC president will issue an amended phase two scoping memo in the near future in order to refocus the direction of the proceeding.

On December 19, 2019, CPUC president and newly assigned commissioner issued an amended Phase 2 scoping memo and ruling. Pursuant to the ruling, the issues to be considered in the amended Phase 2 include:

- updates or changes to existing PSPS guidelines to promote public safety in advance of the 2020 wildfire season;
- proposed guidelines related to a variety of topics including (1) server and website capacity; (2) identification of transit corridors and critical transportation infrastructure dependent on back-up generation during a PSPS event; (3) operations and locations of Community Resource Centers; (4) possible creation of a wildfire safety community advisory board for each utility; (5) PSPS planning exercises in advance of wildfire season; (6) communication and notification during PSPS events when communication services may be disrupted; (7) assistance to medical baseline customers in the near term; (8) plans to better execute identification, communication, and contact with vulnerable populations that may not be considered medical baseline.

On January 30, 2020, the CPUC proposed new guidelines. Parties are given the opportunity to submit opening and reply comments on the guidelines on February 19, 2020 and February 26, 2020, respectively. A proposed decision is anticipated in May 2020.

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

Order to Show Cause Against the Utility Related to Implementation of the October 2019 PSPS Events

On November 12, 2019, the assigned commissioner and ALJ in the OIR to Examine Utility De-energization of Power Lines in Dangerous Conditions issued an order to show cause directing the Utility to show cause why it should not be sanctioned for violations of law or CPUC decisions related to the PSPS events of October 9-12, 2019 and October 23-November 1, 2019.

A prehearing conference was held on December 4, 2019, and the assigned commissioner and ALJ issued a ruling on December 23, 2019 and set forth issues to be determined in the order to show cause, including related to failures associated with the Utility's website, online maps, data transfer portal, advanced notice to customers, and staffing at its call centers in connection with its October 9-12, PSPS event, as well as advance notice to customers in connection with the October 23-25, 2019 and the October 26-November 1, 2019 PSPS event.

The Utility filed its testimony with the CPUC on February 5, 2020. Parties' testimony is due February 28, 2020; concurrent rebuttal is due March 16, 2020; and hearings, if necessary, will be held April 1-3, 2020.

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

OII to Examine the Late 2019 Public Safety Power Shutoff Events

On November 13, 2019, the CPUC issued an OII to determine “whether California’s investor-owned utilities prioritized safety and complied with the Commission’s regulations and requirements with respect to their Public Safety Power Shutoff (PSPS) events in late 2019.” The first phase of this proceeding will assess for each utility, among other things, (1) the effectiveness of the utility’s procedures to notify the public of the PSPS events, (2) the utility’s communication and coordination with first responders, local jurisdictions and state agencies, and (3) the utility’s management of its resources to ensure public safety. In later phases of this proceeding, the CPUC may consider taking action if it finds violations of statutes or its decisions or general orders have been committed and to enforce compliance, if necessary.

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

Power Charge Indifference Adjustment OIR

In 2017, the CPUC initiated the PCIA Rulemaking to make refinements to the PCIA, a cost recovery mechanism to ensure that customers that leave the Utility’s bundled service for a non-Utility provider pay their fair share of the above market costs associated with long-term power purchase commitments and Utility-owned generation made on their behalf. The above market costs of the Utility’s generation portfolio are calculated using benchmarks for energy, resource adequacy (RA) and RPS attributes. On October 11, 2018, the CPUC approved a phase one decision to modify the PCIA methodology establishing:

- calculation of the PCIA rate using benchmark values that more closely resemble actual market prices for RA and RPS;
- continued recovery of legacy Utility-owned generation costs from departed load customers;
- elimination of the 10-year limit on PCIA cost recovery for post-2002 Utility owned generation and certain storage costs; and
- an annual true-up of the PCIA rate based on actual market revenues.

The Utility implemented a revised PCIA reflecting this decision in rates as of July 1, 2019.

On December 19, 2018, the CPUC initiated Phase 2 of the PCIA proceeding to address unresolved issues from phase one, separated into three Working Groups. In Working Group 1, the CPUC directed parties to (1) establish the method to annually update the RA and RPS price benchmarks, (2) determine the process for the annual true-up of PCIA rates to reflect actual market outcomes, and (3) determine the proper billing factors for setting the PCIA rate. A PD was issued on September 6, 2019. On October 10, 2019, the CPUC approved a final decision that:

- approves a methodology for annually setting the price benchmark for RA and RPS based on market transactions of all load-serving entities occurring within the past 12 months;
- values any unsold RA and RPS attributes at zero for calculating the PCIA true-up at year end, meaning that bundled customers are not responsible for paying for RA and RPS attributes that are not needed for compliance; and
- establishes that the PCIA rates shall be calculated using the forecasted sales of customers in a particular billing group, rather than using system-level sales, to prevent a persistent under-collection of PCIA rates.

In Working Group 2, the CPUC directed parties to develop a framework evaluating and approving a PCIA prepayment framework, whereby departed load customers could eliminate their PCIA obligation through an up-front payment. The working group issued a final report on December 9, 2019 containing proposed guiding principles that the CPUC should apply when reviewing prepayment applications. A PD is expected in the first quarter of 2020.

Lastly, in Working Group 3 the CPUC directed parties to develop structures and rules governing how the Utility addresses excess resources in its portfolio due to load loss to CCA and DA, including standards for active management of the Utility’s portfolios. A PD is expected in the third quarter of 2020.

LEGISLATIVE AND REGULATORY INITIATIVES

Senate Bill 901

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 CHT. 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 OIR, which establishes a methodology to establish the CHT in future applications under Section 451.2(a), but determines that a utility that has filed for relief under Chapter 11 cannot access the CHT. 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. (See “Regulatory Matters - OIR Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901” above.)

In addition, SB 901 requires utilities to submit annual wildfire mitigation plans for approval by the CPUC on a schedule to be established by the CPUC. The wildfire mitigation plan must include the components specified in SB 901, such as identification and prioritization of wildfire risks, and drivers for those risks; plans for vegetation management; actions to harden the system, prepare for, and respond to events; and protocols for disabling reclosers and deenergizing the system. The CPUC has three months to approve a utility’s plan, with the ability to extend the deadline. The CPUC will conduct an annual compliance review, which will be supported by an independent evaluator’s report. The CPUC will complete the compliance review within 18 months. SB 901 establishes factors to be considered by the CPUC when setting penalties for failure to substantially comply with the plan. Costs associated with the wildfire mitigation plan are tracked in a memorandum account, and the costs of implementing the plan will be assessed in each utility’s GRC proceeding, or other application proceedings. The Utility is unable to predict the timing or outcome of the CPUC’s review of the wildfire mitigation plan, the results of the CPUC compliance review of wildfire mitigation plan implementation, or the timing or extent of cost recovery for wildfire mitigation plan activities. Subsequent bills including AB 1054, AB 111, SB 70, SB 167, SB 247, and SB 560, modified the wildfire mitigation plan requirements, including expanding the plan coverage to three years, adding additional components and requirements and transferring review of the plans to a new Wildfire Safety Division of the CPUC beginning January 1, 2020, and later to an office in the Natural Resources Agency beginning July 1, 2021.

Assembly Bill 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) \$1.0 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.

Each of California’s large investor-owned electric utility companies that are not currently subject to Chapter 11 (Southern California Edison and San Diego Gas & Electric Company) has elected to participate in the Wildfire Fund to be established under AB 1054. On July 23, 2019, the Utility notified the CPUC of its intent to participate in the Wildfire Fund (which participation is subject to the conditions set forth in AB 1054, including those conditions outlined below).

The Wildfire Fund to be established under AB 1054 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. Electric utility companies that draw from the Wildfire 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 of 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 Wildfire Fund, resulting in a draw-down of the Wildfire 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 provides that the Wildfire Fund will be established when Southern California Edison and San Diego Gas & Electric Company provide their initial contributions. On September 11, 2019, Southern California Edison and San Diego Gas & Electric Company notified the CPUC that each had provided its respective initial contribution to the Wildfire Fund.

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.

On August 23, 2019, the CPUC granted the Utility its Initial Safety Certification, which is valid for 12 months. While not a requirement for participation in the Wildfire Fund, a valid safety certification allows the Utility to benefit from AB 1054's disallowance cap. (See "Regulatory Matters - 2019 Wildfire Mitigation Plan" above.)

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.

If the Utility satisfies the requirements to participate in the Wildfire Fund, the Utility will be required to fund its initial contribution upon its emergence from Chapter 11. The Utility's required contributions to the Wildfire Fund will be substantial. Participation in the Wildfire Fund is expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. The Utility is currently evaluating the tax treatment of the required initial and annual contributions. The timing and amount of any potential charges associated with shareholder contributions would also depend on various factors, including the timing of resolution of the Chapter 11 Cases, the expected life of the Wildfire Fund, and the impact of future wildfires on the Wildfire Fund's claims passing capacity. The Proposed Plan filed with the Bankruptcy Court on January 31, 2020 would provide for the financing of such required contributions, but there can be no assurance that PG&E Corporation and the Utility will successfully consummate or implement any such plan, which will ultimately require Bankruptcy Court, creditor and regulatory approval. Further, there can be no assurance that the expected benefits of participating in the Wildfire Fund ultimately outweigh its substantial costs.

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 estimate 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.

AB 1054 includes certain modifications to the "just and reasonable" standard to be utilized by the CPUC in determining applications for recovery of wildfire-related costs. These modifications will apply to wildfires occurring following the effective date of AB 1054. AB 1054 provides that costs and expenses arising from any such wildfires "are just and reasonable if the conduct of the electrical corporation related to the ignition was consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances, at the relevant point in time, and based on the information available to the electrical corporation at the relevant point of time." Further, in applying such standard, the CPUC is directed to take into account factors "both within and beyond the utility's control that may have exacerbated the costs and expenses, including humidity, temperature, and winds." Finally, AB 1054 modifies the circumstances under which an electric utility company bears the burden of demonstrating that its conduct was reasonable in accordance with the above standard.

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.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Item 1A. Risk Factors, "Environmental Regulation" in Item 1. and "Environmental Remediation Contingencies" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit. The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes.

Commodity Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs in its gas transmission and storage rate cases through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately \$9 million and \$11 million at December 31, 2019 and 2018, respectively. (See Note 10 of the Notes to the Consolidated Financial Statements in Item 8. for further discussion of price risk management activities.)

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2019 and 2018, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be \$45 million and \$24 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. (See Note 5 of the Notes to the Consolidated Financial Statements in Item 8. for further discussion of interest rates.)

Energy Procurement Credit Risk

The Utility conducts business with counterparties mainly in the energy industry to purchase electricity or gas, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's energy procurement credit risk exposure to its counterparties:

| (in millions) | Gross Credit Exposure Before Credit Collateral ⁽¹⁾ | Credit Collateral | Net Credit Exposure ⁽²⁾ | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|-----------------------|---|-------------------|------------------------------------|--|---|
| December 31, 2019 | \$ 106 | \$ (50) | \$ 56 | 3 | \$ 36 |
| Prior year period end | \$ 137 | \$ (52) | \$ 85 | 3 | \$ 64 |

⁽¹⁾ Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.

⁽²⁾ Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

The preparation of the Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates and assumptions. These accounting policies and their key characteristics are outlined below.

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. 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.

Loss Contingencies

As discussed below, PG&E Corporation and the Utility have recorded material accruals for various wildfire-related, enforcement and legal matters, and environmental remediation liabilities. PG&E Corporation and the Utility have also recorded insurance receivables for third-party claims.

Wildfire-Related Liabilities

PG&E Corporation and the Utility are subject to potential liabilities related to wildfires. PG&E Corporation and the Utility record a wildfire-related liability when it determines that a loss is probable and it can reasonably estimate the loss or a range of losses. The provision is based on the lower end of the range, unless an amount within the range is a better estimate than any other amount.

Potential liabilities related to wildfires depend on various factors, including but not limited to negotiations and settlements or the cause of each fire, contributing causes of the fires (including alternative potential origins, weather and climate related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the extent to which future claims arise, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties or fines that may be imposed by governmental entities. There are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation or the Utility, the number of current and future claims that will be included in a plan of reorganization, and how claims for punitive damages and claims by variously situated persons will be treated and whether such claims will be allowed.

The process for estimating wildfire-related liabilities requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to factors identified above and estimates based on currently available information and prior experience with wildfires. (See Note 14 of the Notes to the Consolidated Financial Statements in Item 8.)

Enforcement and Litigation Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. Actual results may differ materially from these estimates and assumptions. (See Note 14 and "Enforcement and Litigation Matters" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

Environmental Remediation Liabilities

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has a program related to certain former manufactured gas plant sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

At December 31, 2019 and 2018, the Utility's accruals for undiscounted gross environmental liabilities were \$1.3 billion. The Utility's undiscounted future costs could increase to as much as \$2.4 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

Insurance Receivable

The Utility has liability insurance from various insurers, which provides coverage for third-party claims. The Utility records insurance recoveries only when a third-party claim is recorded and it is deemed probable that a recovery of that claim will occur and the Utility can reasonably estimate the amount or its range. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex judgments about future events. Insurance recoveries are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, including contractual liability insurance policy coverage, advice of legal counsel, past experience with similar events, discussions with insurers and other information and events pertaining to a particular matter. (See "Loss Recoveries" in Note 14 and "Insurance" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

Regulatory Accounting

As a regulated entity, the Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. Despite the ongoing losses related to wildfires (See Note 14 of the Notes to the Consolidated Financial Statements), there is no actual or anticipated change in the cost of service regulation of the Utility's operations. Therefore, the Utility continues to apply the accounting ASC 980, *Regulated Operations*. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 3 as well as Note 4 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2019, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of \$8.5 billion and regulatory liabilities (including current regulatory balancing accounts payable) of \$11.2 billion.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods presented. If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. If regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

A portion of the Utility's regulatory asset balances relate to items which could not be anticipated by the Utility during CPUC GRC rate requests resulting from catastrophic events, changes in regulation, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. These accounts, which include the CEMA, WEMA, and FHPMA, among others, allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. While the Utility believes such costs are recoverable, rate recovery requires CPUC authorization in separate proceedings or through a GRC. (For more information, see "Regulatory Matters - Wildfire Expense Memorandum Account," "Regulatory Matters - Catastrophic Expense Memorandum Account," and "Regulatory Matters - Fire Hazard Prevention Memorandum Account" in Item 7. MD&A.)

Additionally, SB 901 provides a mechanism for the CPUC to potentially allow recovery in future rates, through a securitization mechanism, 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. The Utility has made an assessment as of December 31, 2019 and has concluded that the net wildfire-related claims incurred for the 2017 Northern California wildfires do not meet the criteria for recognition as a regulatory asset. The Utility must evaluate the likelihood of recovery in future rates each period. If the criteria are met at a later date, the Utility would recognize a regulatory asset and a related gain in the consolidated income statement in the period in which it is determined that the likelihood of recovery is probable.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

Asset Retirement Obligations

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. (See Notes 3 and 4 of the Notes to the Consolidated Financial Statements in Item 8.)

To estimate its liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2019, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was approximately \$6 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets.

Pension and Other Postretirement Benefit Plans

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Adjustments to the pension and other benefit obligation are based on the differences between actuarial assumptions and actual plan results. These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses. (See Note 12 of the Notes to the Consolidated Financial Statements in Item 8.)

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2019 is 6.3%, gradually decreasing to the ultimate trend rate of 4.5% in 2027 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit 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 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 and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2019 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2019 |
|----------------------------------|---|-----------------------------------|---|
| Discount rate | (0.50)% | \$ 80 | \$ 1,665 |
| Rate of return on plan assets | (0.50)% | 76 | — |
| Rate of increase in compensation | 0.50 % | 39 | 376 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2019 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2019 |
|-------------------------------|---|---|---|
| Health care cost trend rate | 0.50 % | \$ 8 | \$ 64 |
| Discount rate | (0.50)% | 8 | 139 |
| Rate of return on plan assets | (0.50)% | 11 | — |

NEW ACCOUNTING PRONOUNCEMENTS

See Note 3 of the Notes to the Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in MD&A in Item 7 and in Note 10: Derivatives and Note 11: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PG&E CORPORATION (DEBTOR-IN-POSSESSION) CONSOLIDATED STATEMENTS OF INCOME (in millions, except per share amounts)

| | Year ended December 31, | | |
|--|-------------------------|-------------------|-----------------|
| | 2019 | 2018 | 2017 |
| Operating Revenues | | | |
| Electric | \$ 12,740 | \$ 12,713 | \$ 13,124 |
| Natural gas | 4,389 | 4,046 | 4,011 |
| Total operating revenues | 17,129 | 16,759 | 17,135 |
| Operating Expenses | | | |
| Cost of electricity | 3,095 | 3,828 | 4,309 |
| Cost of natural gas | 734 | 671 | 746 |
| Operating and maintenance | 8,725 | 7,153 | 6,321 |
| Wildfire-related claims, net of insurance recoveries | 11,435 | 11,771 | — |
| Depreciation, amortization, and decommissioning | 3,234 | 3,036 | 2,854 |
| Total operating expenses | 27,223 | 26,459 | 14,230 |
| Operating Income (Loss) | (10,094) | (9,700) | 2,905 |
| Interest income | 82 | 76 | 31 |
| Interest expense | (934) | (929) | (888) |
| Other income, net | 250 | 424 | 123 |
| Reorganization items, net | (346) | — | — |
| Income (Loss) Before Income Taxes | (11,042) | (10,129) | 2,171 |
| Income tax provision (benefit) | (3,400) | (3,292) | 511 |
| Net Income (Loss) | (7,642) | (6,837) | 1,660 |
| Preferred stock dividend requirement of subsidiary | 14 | 14 | 14 |
| Income (Loss) Available for Common Shareholders | \$ (7,656) | \$ (6,851) | \$ 1,646 |
| Weighted Average Common Shares Outstanding, Basic | 528 | 517 | 512 |
| Weighted Average Common Shares Outstanding, Diluted | 528 | 517 | 513 |
| Net Earnings (Loss) Per Common Share, Basic | \$ (14.50) | \$ (13.25) | \$ 3.21 |
| Net Earnings (Loss) Per Common Share, Diluted | \$ (14.50) | \$ (13.25) | \$ 3.21 |

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

| | Year ended December 31, | | |
|---|-------------------------|-------------------|-----------------|
| | 2019 | 2018 | 2017 |
| Net Income (Loss) | \$ (7,642) | \$ (6,837) | \$ 1,660 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of \$0, \$2, and \$0, at respective dates) | (1) | 4 | 1 |
| Total other comprehensive income (loss) | (1) | 4 | 1 |
| Comprehensive Income (Loss) | (7,643) | (6,833) | 1,661 |
| Preferred stock dividend requirement of subsidiary | 14 | 14 | 14 |
| Comprehensive Income (Loss) Attributable to Common Shareholders | \$ (7,657) | \$ (6,847) | \$ 1,647 |

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
CONSOLIDATED BALANCE SHEETS
(in millions)

| | Balance at December 31, | |
|---|--------------------------------|------------------|
| | 2019 | 2018 |
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | \$ 1,570 | \$ 1,668 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of \$43 and \$56 at respective dates) | 1,287 | 1,148 |
| Accrued unbilled revenue | 969 | 1,000 |
| Regulatory balancing accounts | 2,114 | 1,435 |
| Other | 2,617 | 2,686 |
| Regulatory assets | 315 | 233 |
| Inventories | | |
| Gas stored underground and fuel oil | 97 | 111 |
| Materials and supplies | 550 | 443 |
| Income taxes receivable | — | 23 |
| Other | 646 | 448 |
| Total current assets | 10,165 | 9,195 |
| Property, Plant, and Equipment | | |
| Electric | 62,707 | 59,150 |
| Gas | 22,688 | 21,556 |
| Construction work in progress | 2,675 | 2,564 |
| Other | 20 | 2 |
| Total property, plant, and equipment | 88,090 | 83,272 |
| Accumulated depreciation | (26,455) | (24,715) |
| Net property, plant, and equipment | 61,635 | 58,557 |
| Other Noncurrent Assets | | |
| Regulatory assets | 6,066 | 4,964 |
| Nuclear decommissioning trusts | 3,173 | 2,730 |
| Operating lease right of use asset | 2,286 | — |
| Income taxes receivable | 67 | 69 |
| Other | 1,804 | 1,480 |
| Total other noncurrent assets | 13,396 | 9,243 |
| TOTAL ASSETS | \$ 85,196 | \$ 76,995 |

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

| | Balance at December 31, | |
|---|--------------------------------|------------------|
| | 2019 | 2018 |
| LIABILITIES AND EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | \$ — | \$ 3,435 |
| Long-term debt, classified as current | — | 18,559 |
| Debtor-in-possession financing, classified as current | 1,500 | \$ — |
| Accounts payable | | |
| Trade creditors | 1,954 | 1,975 |
| Regulatory balancing accounts | 1,797 | 1,076 |
| Other | 566 | 464 |
| Operating lease liabilities | 556 | — |
| Disputed claims and customer refunds | — | 220 |
| Interest payable | 4 | 228 |
| Wildfire-related claims | — | 14,226 |
| Other | 1,254 | 1,512 |
| Total current liabilities | 7,631 | 41,695 |
| Noncurrent Liabilities | | |
| Regulatory liabilities | 9,270 | 8,539 |
| Pension and other postretirement benefits | 1,884 | 2,119 |
| Asset retirement obligations | 5,854 | 5,994 |
| Deferred income taxes | 320 | 3,281 |
| Operating lease liabilities | 1,730 | — |
| Other | 2,573 | 2,464 |
| Total noncurrent liabilities | 21,631 | 22,397 |
| Liabilities Subject to Compromise | 50,546 | — |
| Contingencies and Commitments (Notes 14 and 15) | | |
| Equity | | |
| Shareholders' Equity | | |
| Common stock, no par value, authorized 800,000,000 shares; 529,236,741 and 520,338,710 shares outstanding at respective dates | 13,038 | 12,910 |
| Reinvested earnings | (7,892) | (250) |
| Accumulated other comprehensive loss | (10) | (9) |
| Total shareholders' equity | 5,136 | 12,651 |
| Noncontrolling Interest - Preferred Stock of Subsidiary | 252 | 252 |
| Total equity | 5,388 | 12,903 |
| TOTAL LIABILITIES AND EQUITY | \$ 85,196 | \$ 76,995 |

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, | | |
|---|-------------------------|-----------------|----------------|
| | 2019 | 2018 | 2017 |
| Cash Flows from Operating Activities | | | |
| Net income (loss) | \$ (7,642) | \$ (6,837) | \$ 1,660 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 3,234 | 3,036 | 2,854 |
| Allowance for equity funds used during construction | (79) | (129) | (89) |
| Deferred income taxes and tax credits, net | (2,948) | (2,532) | 1,254 |
| Reorganization items, net (Note 2) | 108 | — | — |
| Disallowed capital expenditures | 581 | (45) | 47 |
| Other | 207 | 332 | 307 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (104) | (121) | 67 |
| Wildfire-related insurance receivable | 35 | (1,698) | (21) |
| Inventories | (80) | (73) | (18) |
| Accounts payable | 516 | 409 | 173 |
| Wildfire-related claims | (114) | 13,665 | (129) |
| Income taxes receivable/payable | 23 | (23) | 160 |
| Other current assets and liabilities | 77 | (281) | 42 |
| Regulatory assets, liabilities, and balancing accounts, net | (1,417) | (800) | (387) |
| Liabilities subject to compromise | 12,222 | — | — |
| Other noncurrent assets and liabilities | 197 | (151) | 57 |
| Net cash provided by operating activities | 4,816 | 4,752 | 5,977 |
| Cash Flows from Investing Activities | | | |
| Capital expenditures | (6,313) | (6,514) | (5,641) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 956 | 1,412 | 1,291 |
| Purchases of nuclear decommissioning trust investments | (1,032) | (1,485) | (1,323) |
| Other | 11 | 23 | 23 |
| Net cash used in investing activities | (6,378) | (6,564) | (5,650) |
| Cash Flows from Financing Activities | | | |
| Proceeds from debtor-in-possession credit facility | 1,850 | — | — |
| Repayments of debtor-in-possession credit facility | (350) | — | — |
| Debtor-in-possession credit facility debt issuance costs | (113) | — | — |
| Borrowings under revolving credit facilities | — | 3,960 | — |
| Repayments under revolving credit facilities | — | (775) | — |
| Net repayments of commercial paper, net of discount of \$0, \$1, and \$5 at respective dates | — | (182) | (840) |
| Short-term debt financing | — | 600 | 750 |
| Short-term debt matured | — | (750) | (500) |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of \$0, \$7, and \$32 at respective dates | — | 793 | 2,713 |
| Long-term debt matured or repurchased | — | (795) | (1,445) |
| Common stock issued | 85 | 200 | 395 |
| Common stock dividends paid | — | — | (1,021) |
| Other | (8) | (20) | (107) |
| Net cash provided by (used in) financing activities | 1,464 | 3,031 | (55) |
| Net change in cash, cash equivalents, and restricted cash | (98) | 1,219 | 272 |
| Cash, cash equivalents, and restricted cash at January 1 | 1,675 | 456 | 184 |
| Cash, cash equivalents, and restricted cash at December 31 | \$ 1,577 | \$ 1,675 | \$ 456 |
| Less: Restricted cash and restricted cash equivalents | (7) | (7) | (7) |
| Cash and cash equivalents at December 31 | \$ 1,570 | \$ 1,668 | \$ 449 |

Supplemental disclosures of cash flow information

Cash received (paid) for:

| | | | | | | |
|--------------------------------------|----|------|----|-------|----|-------|
| Interest, net of amounts capitalized | \$ | (10) | \$ | (786) | \$ | (790) |
| Income taxes, net | | — | | (49) | | 162 |

Supplemental disclosures of noncash investing and financing activities

| | | | | | | |
|---|----|-------|----|-----|----|-----|
| Capital expenditures financed through accounts payable | \$ | 826 | \$ | 368 | \$ | 501 |
| Noncash common stock issuances | | — | | — | | 21 |
| Operating lease liabilities arising from obtaining ROU assets | | 2,816 | | — | | — |

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF EQUITY
(in millions, except share amounts)

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Non controlling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---------------------------|---------------------------|------------------------|---|----------------------------------|---|------------------|
| Balance at December 31, 2016 | 506,891,874 | \$ 12,198 | \$ 5,751 | \$ (9) | \$ 17,940 | \$ 252 | \$ 18,192 |
| Net income | — | — | 1,660 | — | 1,660 | — | 1,660 |
| Other comprehensive income | — | — | — | 1 | 1 | — | 1 |
| Common stock issued, net | 7,863,971 | 416 | — | — | 416 | — | 416 |
| Stock-based compensation amortization | — | 18 | — | — | 18 | — | 18 |
| Common stock dividends declared | — | — | (801) | — | (801) | — | (801) |
| Preferred stock dividend requirement of subsidiary | — | — | (14) | — | (14) | — | (14) |
| Balance at December 31, 2017 | 514,755,845 | \$ 12,632 | \$ 6,596 | \$ (8) | \$ 19,220 | \$ 252 | \$ 19,472 |
| Net loss | — | — | (6,837) | — | (6,837) | — | (6,837) |
| Other comprehensive income (loss) | — | — | 5 | (1) | 4 | — | 4 |
| Common stock issued, net | 5,582,865 | 200 | — | — | 200 | — | 200 |
| Stock-based compensation amortization | — | 78 | — | — | 78 | — | 78 |
| Preferred stock dividend requirement of subsidiary | — | — | (14) | — | (14) | — | (14) |
| Balance at December 31, 2018 | 520,338,710 | \$ 12,910 | \$ (250) | \$ (9) | \$ 12,651 | \$ 252 | \$ 12,903 |
| Net loss | — | — | (7,642) | — | (7,642) | — | (7,642) |
| Other comprehensive loss | — | — | — | (1) | (1) | — | (1) |
| Common stock issued, net | 8,898,031 | 85 | — | — | 85 | — | 85 |
| Stock-based compensation amortization | — | 43 | — | — | 43 | — | 43 |
| Balance at December 31, 2019 | 529,236,741 | \$ 13,038 | \$ (7,892) | \$ (10) | \$ 5,136 | \$ 252 | \$ 5,388 |

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF INCOME
(in millions)

| | Year ended December 31, | | |
|--|-------------------------|-------------------|-----------------|
| | 2019 | 2018 | 2017 |
| Operating Revenues | | | |
| Electric | \$ 12,740 | \$ 12,713 | \$ 13,127 |
| Natural gas | 4,389 | 4,047 | 4,011 |
| Total operating revenues | 17,129 | 16,760 | 17,138 |
| Operating Expenses | | | |
| Cost of electricity | 3,095 | 3,828 | 4,309 |
| Cost of natural gas | 734 | 671 | 746 |
| Operating and maintenance | 8,750 | 7,153 | 6,383 |
| Wildfire-related claims, net of insurance recoveries | 11,435 | 11,771 | — |
| Depreciation, amortization, and decommissioning | 3,233 | 3,036 | 2,854 |
| Total operating expenses | 27,247 | 26,459 | 14,292 |
| Operating Income (Loss) | (10,118) | (9,699) | 2,846 |
| Interest income | 82 | 74 | 30 |
| Interest expense | (912) | (914) | (877) |
| Other income, net | 239 | 426 | 119 |
| Reorganization items, net | (320) | — | — |
| Income (Loss) Before Income Taxes | (11,029) | (10,113) | 2,118 |
| Income tax provision (benefit) | (3,407) | (3,295) | 427 |
| Net Income (Loss) | (7,622) | (6,818) | 1,691 |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| Income (Loss) Available for Common Stock | \$ (7,636) | \$ (6,832) | \$ 1,677 |

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

| | Year ended December 31, | | |
|---|-------------------------|-------------------|-----------------|
| | 2019 | 2018 | 2017 |
| Net Income (Loss) | \$ (7,622) | \$ (6,818) | \$ 1,691 |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of \$1, \$2, and \$3, at respective dates) | 2 | (5) | 4 |
| Total other comprehensive income (loss) | 2 | (5) | 4 |
| Comprehensive Income (Loss) | \$ (7,620) | \$ (6,823) | \$ 1,695 |

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
CONSOLIDATED BALANCE SHEETS
(in millions)

| | Balance at December 31, | |
|---|--------------------------------|------------------|
| | 2019 | 2018 |
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | \$ 1,122 | \$ 1,295 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of \$43 and \$56 at respective dates) | 1,287 | 1,148 |
| Accrued unbilled revenue | 969 | 1,000 |
| Regulatory balancing accounts | 2,114 | 1,435 |
| Other | 2,647 | 2,688 |
| Regulatory assets | 315 | 233 |
| Inventories | | |
| Gas stored underground and fuel oil | 97 | 111 |
| Materials and supplies | 550 | 443 |
| Income taxes receivable | — | 5 |
| Other | 635 | 448 |
| Total current assets | 9,736 | 8,806 |
| Property, Plant, and Equipment | | |
| Electric | 62,707 | 59,150 |
| Gas | 22,688 | 21,556 |
| 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 |
| Other Noncurrent Assets | | |
| Regulatory assets | 6,066 | 4,964 |
| Nuclear decommissioning trusts | 3,173 | 2,730 |
| Operating lease right of use asset | 2,279 | — |
| Income taxes receivable | 66 | 66 |
| Other | 1,659 | 1,348 |
| Total other noncurrent assets | 13,243 | 9,108 |
| TOTAL ASSETS | \$ 84,614 | \$ 76,471 |

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

| | Balance at December 31, | |
|--|--------------------------------|------------------|
| | 2019 | 2018 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | \$ — | \$ 3,135 |
| Long-term debt, classified as current | — | 18,209 |
| Debtor-in-possession financing, classified as current | 1,500 | — |
| Accounts payable | | |
| Trade creditors | 1,949 | 1,972 |
| Regulatory balancing accounts | 1,797 | 1,076 |
| Other | 675 | 498 |
| Operating lease liabilities | 553 | — |
| Disputed claims and customer refunds | — | 220 |
| Interest payable | 4 | 227 |
| Wildfire-related claims | — | 14,226 |
| Other | 1,263 | 1,497 |
| Total current liabilities | 7,741 | 41,060 |
| Noncurrent Liabilities | | |
| Regulatory liabilities | 9,270 | 8,539 |
| Pension and other postretirement benefits | 1,884 | 2,026 |
| Asset retirement obligations | 5,854 | 5,994 |
| Deferred income taxes | 442 | 3,405 |
| Operating lease liabilities | 1,726 | — |
| Other | 2,626 | 2,492 |
| Total noncurrent liabilities | 21,802 | 22,456 |
| Liabilities Subject to Compromise | 49,736 | — |
| Contingencies and Commitments (Notes 14 and 15) | | |
| Shareholders' Equity | | |
| Preferred stock | 258 | 258 |
| Common stock, \$5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 8,550 | 8,550 |
| Reinvested earnings | (4,796) | 2,826 |
| Accumulated other comprehensive income (loss) | 1 | (1) |
| Total shareholders' equity | 5,335 | 12,955 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | \$ 84,614 | \$ 76,471 |

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, | | |
|---|-------------------------|-----------------|----------------|
| | 2019 | 2018 | 2017 |
| Cash Flows from Operating Activities | | | |
| Net income (loss) | \$ (7,622) | \$ (6,818) | \$ 1,691 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 3,233 | 3,036 | 2,854 |
| Allowance for equity funds used during construction | (79) | (129) | (89) |
| Deferred income taxes and tax credits, net | (2,952) | (2,548) | 1,103 |
| Reorganization items, net (Note 2) | 97 | — | — |
| Disallowed capital expenditures | 581 | (45) | 47 |
| Other | 167 | 258 | 283 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | (132) | (122) | 66 |
| Wildfire-related insurance receivable | 35 | (1,698) | (21) |
| Inventories | (80) | (73) | (18) |
| Accounts payable | 579 | 421 | 173 |
| Wildfire-related claims | (114) | 13,665 | (129) |
| Income taxes receivable/payable | 5 | (5) | 159 |
| Other current assets and liabilities | 101 | (301) | 59 |
| Regulatory assets, liabilities, and balancing accounts, net | (1,417) | (800) | (390) |
| Liabilities subject to compromise | 12,194 | — | — |
| Other noncurrent assets and liabilities | 214 | (137) | 128 |
| Net cash provided by operating activities | 4,810 | 4,704 | 5,916 |
| Cash Flows from Investing Activities | | | |
| Capital expenditures | (6,313) | (6,514) | (5,641) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 956 | 1,412 | 1,291 |
| Purchases of nuclear decommissioning trust investments | (1,032) | (1,485) | (1,323) |
| Other | 11 | 23 | 23 |
| Net cash used in investing activities | (6,378) | (6,564) | (5,650) |
| Cash Flows from Financing Activities | | | |
| Proceeds from debtor-in-possession credit facility | 1,850 | — | — |
| Repayments of debtor-in-possession credit facility | (350) | — | — |
| Debtor-in-possession credit facility debt issuance costs | (97) | — | — |
| Borrowings under revolving credit facilities | — | 3,535 | — |
| Repayments under revolving credit facilities | — | (650) | — |
| Net repayments of commercial paper, net of discount of \$0, \$0, and \$5 at respective dates | — | (50) | (972) |
| Short-term debt financing | — | 250 | 750 |
| Short-term debt matured | — | (750) | (500) |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of \$0, \$7, and \$32 at respective dates | — | 793 | 2,713 |
| Long-term debt matured or repurchased | — | (445) | (1,445) |
| Preferred stock dividends paid | — | — | (14) |
| Common stock dividends paid | — | — | (784) |
| Equity contribution from PG&E Corporation | — | 45 | 455 |
| Other | (8) | (20) | (93) |
| Net cash provided by financing activities | 1,395 | 2,708 | 110 |
| Net change in cash, cash equivalents, and restricted cash | (173) | 848 | 376 |
| Cash, cash equivalents, and restricted cash at January 1 | 1,302 | 454 | 78 |
| Cash, cash equivalents, and restricted cash at December 31 | \$ 1,129 | \$ 1,302 | \$ 454 |
| Less: Restricted cash and restricted cash equivalents | (7) | (7) | (7) |
| Cash and cash equivalents at December 31 | \$ 1,122 | \$ 1,295 | \$ 447 |

Supplemental disclosures of cash flow information

| | | | | | | |
|--------------------------------------|----|-----|----|-------|----|-------|
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | \$ | (7) | \$ | (773) | \$ | (781) |
| Income taxes, net | | — | | (59) | | 162 |

Supplemental disclosures of noncash investing and financing activities

| | | | | | | |
|---|----|-------|----|-----|----|-----|
| Capital expenditures financed through accounts payable | \$ | 826 | \$ | 368 | \$ | 501 |
| Operating lease liabilities arising from obtaining ROU assets | | 2,807 | | — | | — |

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions)

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|-------------------------------------|--------------------|-----------------|----------------------------------|------------------------|--|----------------------------------|
| Balance at December 31, 2016 | \$ 258 | \$ 1,322 | \$ 8,050 | \$ 8,763 | \$ 2 | \$ 18,395 |
| Net income | — | — | — | 1,691 | — | 1,691 |
| Other comprehensive income | — | — | — | — | 4 | 4 |
| Equity contribution | — | — | 455 | — | — | 455 |
| Common stock dividend | — | — | — | (784) | — | (784) |
| Preferred stock dividend | — | — | — | (14) | — | (14) |
| Balance at December 31, 2017 | \$ 258 | \$ 1,322 | \$ 8,505 | \$ 9,656 | \$ 6 | \$ 19,747 |
| Net loss | — | — | — | (6,818) | — | (6,818) |
| Other comprehensive income (loss) | — | — | — | 2 | (7) | (5) |
| Equity contribution | — | — | 45 | — | — | 45 |
| Preferred stock dividend | — | — | — | (14) | — | (14) |
| Balance at December 31, 2018 | \$ 258 | \$ 1,322 | \$ 8,550 | \$ 2,826 | \$ (1) | \$ 12,955 |
| Net loss | — | — | — | (7,622) | — | (7,622) |
| Other comprehensive income | — | — | — | — | 2 | 2 |
| Balance at December 31, 2019 | \$ 258 | \$ 1,322 | \$ 8,550 | \$ (4,796) | \$ 1 | \$ 5,335 |

See accompanying Notes to the Consolidated Financial Statements.

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 Knighthood as plan proponents and is not in a form acceptable to each of Abrams and Knighthood, (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:

| (in millions) | Petition Date Through December 31, 2019 | | |
|--|---|---------------------------------|-------------------------------|
| | 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:

| (in millions) | Year Ended | |
|--|------------------|------------------|
| | 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 | Balance at December 31, | |
|--|------------------|-------------------------|------------------|
| | Lives (years) | 2019 | 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 | <u>\$ (25)</u> | <u>\$ 17</u> | <u>\$ (8)</u> |
| 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 | <u>4</u> | <u>—</u> | <u>4</u> |
| Ending balance | <u>\$ (21)</u> | <u>\$ 17</u> | <u>\$ (4)</u> |

⁽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:

| (in millions) | Balance at December 31, | | Recovery Period |
|--|-------------------------|-----------------|-----------------|
| | 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:

| (in millions) | Balance at December 31, | |
|---|-------------------------|-----------------|
| | 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:

| (in millions) | Receivable Balance at December 31, | |
|---|---------------------------------------|-----------------|
| | 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 |

| (in millions) | Payable Balance at December 31, | |
|--|------------------------------------|-----------------|
| | 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, | | Treatment under Proposed Plan ⁽¹⁾ |
|---|-------------------------------|--------------|-----------|---|
| | | 2019 | 2018 | |
| 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.

| (in millions, except per share amounts) | Year Ended December 31, | | |
|---|-------------------------|-------------------|----------------|
| | 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:

| (in millions) | PG&E Corporation | | | Utility | | |
|--|------------------|---------------|---------------|---------------|---------------|---------------|
| | 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:

| Underlying Product | Instruments | Contract Volume At December 31, | |
|---|--|------------------------------------|-------------|
| | | 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:

| (in millions) | Commodity Risk | | | Total Derivative Balance |
|---------------------------------|-----------------------------|-------------|-----------------|-----------------------------|
| | Gross Derivative Balance | Netting | Cash Collateral | |
| 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:

| (in millions) | Commodity Risk | | | Total Derivative Balance |
|---------------------------------|-----------------------------|-------------|-----------------|-----------------------------|
| | Gross Derivative Balance | Netting | Cash Collateral | |
| 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.

| (in millions) | Fair Value Measurements | | | | |
|--|-------------------------|---------------|---------------|------------------------|-----------------|
| | At December 31, 2019 | | | | |
| | 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 | | Valuation Technique | Unobservable Input | Range ⁽¹⁾ /Weighted-Average Price ⁽²⁾ |
|-------------------------------|---------------|-------------|---------------------|--------------------|---|
| | Assets | Liabilities | | | |
| Fair Value Measurement | | | | | |
| Congestion revenue rights | \$ 140 | \$ 44 | Market approach | CRR auction | \$ (20.20) - 20.20 / 0.28 |
| Power purchase | \$ 21 | \$ 112 | Discounted cash | 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 | | Valuation | Unobservable | Range ⁽¹⁾ |
|---------------------------|----------------------|-------------|----------------------|--------------------|----------------------|
| | At December 31, 2018 | | | | |
| Fair Value Measurement | Assets | Liabilities | Technique | Input | |
| 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:

| (in millions) | Price Risk Management Instruments | |
|--|-----------------------------------|--------------|
| | 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):

| (in millions) | At December 31, | | | |
|---------------------------------|-----------------|--------------------|-----------------|--------------------|
| | 2019 | | 2018 | |
| | 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.

| (in millions) | Fair Value Measurements | | | | | | | |
|--|-------------------------|-----------------|--------------|------------------|------------------|-----------------|-------------|------------------|
| | At December 31, | | | | | | | |
| | 2019 | | | | 2018 | | | |
| | 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:

| (in millions) | Year Ended December 31, | | |
|--|-------------------------|-------|-------|
| | 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's 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 Kincadee 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 Kincadee fire remains under Cal Fire's investigation and there are a number of unknown facts surrounding the cause of the 2019 Kincadee 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 Kincadee 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 | \$ 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:

| (in millions) | Balance at | |
|--|----------------------|----------------------|
| | 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:

| (in millions) | Power Purchase Agreements | | | | | |
|-----------------------------------|----------------------------------|----------------------------|---------------|--------------------|---------------------|------------------|
| | 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.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

| (in millions, except per share amounts) | Quarter ended | | | |
|---|---------------|--------------|----------|----------|
| | December 31 | September 30 | June 30 | March 31 |
| 2019 | | | | |
| PG&E CORPORATION | | | | |
| Operating revenues ⁽¹⁾ | \$ 4,743 | \$ 4,432 | \$ 3,943 | \$ 4,011 |
| Operating income (loss) | (4,343) | (2,300) | (3,640) | 189 |
| Income tax provision (benefit) ⁽²⁾ | (1,468) | (729) | (1,119) | (84) |
| Net income (loss) ⁽³⁾ | (3,613) | (1,616) | (2,549) | 136 |
| Income (loss) available for common shareholders | (3,617) | (1,619) | (2,553) | 136 |
| Comprehensive income (loss) | (3,607) | (1,619) | (2,553) | 136 |
| Net earnings (loss) per common share, basic | (6.84) | (3.06) | (4.83) | 0.25 |
| Net earnings (loss) per common share, diluted | (6.84) | (3.06) | (4.83) | 0.25 |
| UTILITY | | | | |
| Operating revenues ⁽¹⁾ | \$ 4,743 | \$ 4,432 | \$ 3,943 | \$ 4,011 |
| Operating income (loss) | (4,350) | (2,302) | (3,638) | 172 |
| Income tax provision (benefit) ⁽²⁾ | (1,464) | (738) | (1,119) | (86) |
| Net income (loss) ⁽³⁾ | (3,595) | (1,610) | (2,550) | 133 |
| Income (loss) available for common stock | (3,602) | (1,613) | (2,554) | 133 |
| Comprehensive income (loss) | (3,593) | (1,610) | (2,550) | 133 |
| 2018 | | | | |
| PG&E CORPORATION | | | | |
| Operating revenues ⁽⁴⁾ | \$ 4,088 | \$ 4,381 | \$ 4,234 | \$ 4,056 |
| Operating income | (9,530) | 696 | (1,465) | 599 |
| Income tax provision ⁽⁵⁾ | (2,765) | 15 | (593) | 51 |
| Net income ⁽⁶⁾ | (6,869) | 567 | (980) | 445 |
| Income available for common shareholders | (6,873) | 564 | (984) | 442 |
| Comprehensive income | (6,866) | 568 | (980) | 445 |
| Net earnings per common share, basic | (13.24) | 1.09 | (1.91) | 0.86 |
| Net earnings per common share, diluted | (13.24) | 1.09 | (1.91) | 0.86 |
| UTILITY | | | | |
| Operating revenues ⁽⁴⁾ | \$ 4,088 | \$ 4,382 | \$ 4,234 | \$ 4,056 |
| Operating income | (9,530) | 697 | (1,465) | 599 |
| Income tax provision ⁽⁵⁾ | (2,765) | 14 | (592) | 48 |
| Net income ⁽⁶⁾ | (6,865) | 571 | (976) | 452 |
| Income available for common stock | (6,869) | 568 | (980) | 449 |
| Comprehensive income | (6,871) | 571 | (975) | 452 |

⁽¹⁾ In the third and fourth quarters of 2019, the Utility recorded additional base revenues authorized in the 2017 GRC and 2019 GT&S rate cases.

⁽²⁾ In the second, third and fourth quarters of 2019, the Utility had an income tax benefit as a result of pre-tax losses.

⁽³⁾ In the second quarter of 2019, the Utility recorded a pre-tax charge of \$2.0 billion as a result of the 2017 Northern California wildfires and a pre-tax charge of \$1.9 billion as a result of the 2018 Camp fire. In the third quarter of 2019, the Utility recorded a pre-tax charge of \$2.0 billion as a result of the 2017 Northern California wildfires and a pre-tax charge of \$526 million as a result of the 2018 Camp fire. In the fourth quarter of 2019, the Utility recorded a pre-tax charge of \$5.0 billion associated with wildfire-related third-party claims.

⁽⁴⁾ In the first quarter of 2018, the Utility recorded \$81 million as provisions for rate refunds for the 2017 GRC and 2015 GT&S rate case as a result of the Tax Act.

⁽⁵⁾ In the second and fourth quarters of 2018, the Utility had an income tax benefit as a result of pre-tax losses.

⁽⁶⁾ In the second quarter of 2018, the Utility recorded a pre-tax charge of \$2.5 billion as a result of the 2017 Northern California wildfires. In the fourth quarter of 2018, the Utility recorded a pre-tax charge of \$10.5 billion as a result of the 2018 Camp fire and an additional \$1.0 billion pre-tax charge for the 2017 Northern California wildfires.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and the Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2019, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2019.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of PG&E Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PG&E Corporation (“Debtor-in-Possession”) and subsidiaries (the “Company”) as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2019, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America (“GAAP”).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2020, expressed an unqualified opinion on the Company’s internal control over financial reporting.

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 (wildfire-related contingencies are also communicated as a critical audit matter below), 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.

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 pre-petition liabilities, the settlement amounts for allowed claims, or the status and priority thereof; (3) as to shareholder accounts, the effect of any changes that may be made in the capitalization of the Company; or (4) as to operations, the effect of any changes that may be made in its business.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Wildfire-Related Contingencies — Refer to Note 14 to the financial statements (also see going concern explanatory paragraph above)

Critical Audit Matter Description

The Company has significant contingencies related to the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire (the “wildfires”). The Company has recorded estimated liabilities of \$25.5 billion as of December 31, 2019, which is comprised of amounts under agreements with claimholders and represents its best estimate of probable losses as of December 31, 2019. The Company also believes it is reasonably possible that it will incur a loss in connection with the 2019 Kincadee fire but cannot reasonably estimate the amount or range of such possible loss.

We identified wildfire-related contingencies and the related disclosure as a critical audit matter because (1) of the significant judgments made by management to estimate losses and (2) the outcome of the wildfire-related contingencies materially affects the Company’s financial position, results of operations, and cash flows. This required the application of a high degree of judgment and extensive effort when performing audit procedures to evaluate the reasonableness of management’s estimated losses and disclosure related to wildfire-related contingencies.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management’s judgment regarding its estimated losses for wildfire-related contingencies and its related disclosure included the following, among others:

- We tested the effectiveness of management’s internal controls over (1) the Company’s determination of whether a loss was probable and/or reasonably possible; (2) the determination of the significant assumptions, including the information gained through negotiations, settlements, and advice of legal counsel that may impact the valuation of the liability; and (3) the financial statement disclosures related to the wildfires.
- We evaluated management’s judgments related to whether a loss was probable and/or reasonably possible for the wildfires by inquiring of management and the Company’s legal counsel regarding the amounts of probable and reasonably possible losses, including the potential impact of information gained through negotiations, settlements, and advice of legal counsel, and reading settlement agreements and external information for any evidence that might contradict management’s assertions.
- We evaluated the estimation methodology for determining the amount of probable loss through inquiries with management; we tested the significant assumptions used in the valuation of the liability, including but not limited to newly identified information gained through negotiations, settlements, and advice of legal counsel; and we compared the recorded liabilities to settlement agreements with claimholders.
- We read the legal letters from the Company’s external and internal legal counsel regarding information from negotiations and settlements, and evaluated whether the information therein was consistent with the information obtained in our procedures.
- We evaluated whether the Company’s disclosures were appropriate and consistent with the information obtained in our procedures.

Impact of Rate Regulation on the Financial Statements — Refer to Notes 3, 4 and 14 to the financial statements

Critical Audit Matter Description

The Company's subsidiary, Pacific Gas & Electric Company, follows accounting principles for rate-regulated entities and collects rates from customers to recover "revenue requirements" that have been authorized by the California Public Utility Commission (the "CPUC") or the Federal Energy Regulatory Commission (the "FERC") based on its cost of providing service. Pacific Gas & Electric Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. Pacific Gas & Electric Company 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.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of cost recovery and future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery of incurred costs in current or future rates due in part to the uncertainty related to approval from the rate regulators, (2) a disallowance of costs of recently completed plant or plant under construction, and (3) a refund to customers.

Auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due its inherent complexities and a high degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions that the costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset under GAAP and are recorded at the appropriate amount.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of specialized rules to account for the effects of cost-based rate regulation and the uncertainty of future decisions by the rate regulators, and that the costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset and are appropriately being recorded as a regulatory asset included the following, among others:

- We tested the effectiveness of controls over (1) the evaluation of the application of specialized rules to account for the effects of cost-based rate regulation, (2) the evaluation of the likelihood of (a) the recovery in future rates of costs incurred as property, plant, and equipment or deferred as regulatory assets; (b) regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; and (c) a refund or a future reduction in rates that should be reported as regulatory liabilities; (3) management's determination that costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset and are appropriately being recorded as a regulatory asset and (4) the review of financial statement disclosures related to these matters.
- With the assistance of professionals in our firm having expertise in regulatory accounting, we evaluated the Company's conclusion that it should apply the specialized rules to account for the effects of cost-based rate regulation.
- We read relevant regulatory orders issued by the CPUC for the Company and other public utilities in California, procedural filings, filings made by intervenors, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of the CPUC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- For regulatory matters in process (e.g., applications for cost recovery, regulatory investigations and the CPUC's review of incurred capital), we inspected the Company's filings with the CPUC and the filings with the CPUC by intervenors that may impact the Company's future rates, for any evidence that might contradict management's assertions.
- For regulatory assets approved by a CPUC decision for tracking purposes, we selected samples of costs and evaluated whether they met the definition of a regulatory asset by comparing the cost to the description of the costs approved by a CPUC decision and were appropriately recorded to the regulatory asset.

- We inquired of management about property, plant, and equipment that has not been approved by the CPUC for recovery or may be disallowed. We inspected minutes of the Board of Directors, regulatory orders, and other filings with the regulators to identify any evidence that may contradict management’s assertion regarding probability of a disallowance.
- We evaluated whether the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments, were appropriate and consistent with the information obtained in our procedures.

Wildfire Fund under AB 1054 — Refer to Note 14 to the financial statements

Critical Audit Matter Description

On July 12, 2019, the California Governor signed into law Assembly Bill (“AB”) 1054, a bill which provides for the establishment of a statewide fund (“Wildfire Fund”) that will be available for eligible California 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. The Company’s subsidiary, Pacific Gas & Electric Company, obtained the U.S. Bankruptcy Court for the Northern District of California (“Bankruptcy Court”) approval to participate in the Wildfire Fund and to make any initial and annual Wildfire Fund contributions, which are expected to be approximately \$4.8 billion and \$193 million, respectively, upon emergence from Chapter 11 of the U.S. Bankruptcy Code (“Chapter 11 Case”). To participate in the Wildfire Fund, Pacific Gas & Electric Company must emerge from its Chapter 11 Case by June 30, 2020, along with other eligibility requirements.

We identified the Company’s disclosure of the uncertainties related to the timing of funding (e.g., emergence from the Chapter 11 Case and meeting other eligibility requirements), the accounting for any contributions made to the Wildfire Fund, and other material information included in AB 1054, as a critical audit matter because of the significant judgments made by management to determine the extent of the disclosure, including its accounting conclusion related to the initial and annual contributions, as there is no relevant explicit guidance for accounting for contributions to a statewide fund and thus accounting guidance must be applied analogously. This required the application of a high degree of auditor judgment and extensive effort when performing audit procedures to evaluate the reasonableness of management’s judgments.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the disclosures of the uncertainties associated with the timing of funding, material information included in AB 1054, and the accounting for contributions included the following, among others:

- We tested the effectiveness of controls over the review of financial statement disclosures of the uncertainties associated with the timing of the funding, material information included in AB 1054, and the accounting for contributions.
- With the assistance of professionals in our firm having expertise in insurance accounting, we evaluated management’s judgments related to its determination of the accounting for any contributions made to the Wildfire Fund.
- We read the terms of the AB 1054 legislation and the Company’s accounting analysis and evaluated any clauses that contradicted the Company’s conclusions about the accounting for contributions or the financial statement disclosures.
- We evaluated whether the financial statement disclosures were complete and consistent with the information obtained in our procedures.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 18, 2020

We have served as the Company’s auditor since 1999.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Pacific Gas and Electric Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Pacific Gas and Electric Company (“Debtor-in-Possession”) and subsidiaries (the “Utility”) as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, shareholders’ equity, and cash flows, for each of the three years in the period ended December 31, 2019, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Utility as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Utility's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2020 expressed an unqualified opinion on the Utility's internal control over financial reporting.

Going Concern

The accompanying financial statements have been prepared assuming that the Utility will continue as a going concern. As discussed in Notes 1 and 14 to the financial statements, the Utility suffered material losses as a result of the 2017 Northern California wildfires and the 2018 Camp fire, which contributed to the Utility’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.

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 pre-petition liabilities, the settlement amounts for allowed claims, or the status and priority thereof; (3) as to shareholder accounts, the effect of any changes that may be made in the capitalization of the Company; or (4) as to operations, the effect of any changes that may be made in its business.

Basis for Opinion

These financial statements are the responsibility of the Utility's management. Our responsibility is to express an opinion on the Utility's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 18, 2020

We have served as the Utility's auditor since 1999.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of PG&E Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the “Company”) as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Company and our report dated February 18, 2020, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph regarding certain conditions that give rise to substantial doubt about the Company’s ability to continue as a going concern and an emphasis of matter paragraph concerning the bankruptcy proceedings.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 18, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Pacific Gas and Electric Company

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Pacific Gas and Electric Company and subsidiaries (the “Utility”) as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Utility and our report dated February 18, 2020, expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph regarding certain conditions that give rise to substantial doubt about the Utility’s ability to continue as a going concern and an emphasis of a matter paragraph concerning the bankruptcy proceedings.

Basis for Opinion

The Utility’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Utility’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 18, 2020

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCE DISCLOSURE

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2019, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this 2019 Form 10-K under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

Registered Public Accounting Firm's Report on Internal Control over Financial Reporting

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Amendment to Debt Commitment Letters

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 ("Amendments No. 4 to the Debt Commitment Letters"). The Amendments No. 4 to the Debt Commitment Letters are attached hereto as Exhibits 10.17 and 10.18.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding executive officers of PG&E Corporation and the Utility is set forth under “Executive Officers of the Registrants” at the end of Part I of this 2019 Form 10-K. Other information regarding directors will be included under the heading “Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act will be included under the heading “Section 16(a) Beneficial Ownership Reporting Compliance” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Website Availability of Code of Ethics, Corporate Governance and Other Documents

The following documents are available both on the Corporate Governance section of PG&E Corporation’s website (www.pgecorp.com/corp/about-us/corporate-governance.page) and on the Utility’s website (www.pge.com/en_US/about-pge/company-information/company-information.page, under the Corporate Governance tab): (1) the PG&E Corporation and the Utility’s code of conduct (which meets the definition of “code of ethics” of Item 406(b) of the SEC Regulation S-K) adopted by PG&E Corporation and the Utility and applicable to their directors and employees, including their respective Chief Executive Officer and Presidents, as the case may be, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation’s and the Utility’s respective corporate governance guidelines, and (3) key Board committee charters, including charters for the companies’ Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the code of conduct adopted by PG&E Corporation and the Utility and that apply to their respective Chief Executive Officer and Presidents, as the case may be, Chief Financial Officers, or Controllers, PG&E Corporation and the Utility will post the amended code of ethics on their websites and will disclose any waivers to the code of conduct in a Current Report on Form 8-K.

Procedures for Shareholder Recommendations of Nominees to the Boards of Directors

There were no material changes to the procedures described in PG&E Corporation’s and the Utility’s Joint Proxy Statement relating to the 2019 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation’s or Pacific Gas and Electric Company’s Boards of Directors.

Audit Committees and Audit Committee Financial Expert

Information regarding the Audit Committees of PG&E Corporation and the Utility and the “audit committee financial experts” as defined by the SEC will be included under the headings “Corporate Governance – Board Committee Duties – Audit Committees” and “Corporate Governance – Committee Membership, Independence, and Qualifications” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

Information responding to Item 11, for each of PG&E Corporation and the Utility, will be included under the headings “Compensation Discussion and Analysis,” “Compensation Committee Report,” “Summary Compensation Table - 2019,” “Grants of Plan-Based Awards in 2019,” “Outstanding Equity Awards at Fiscal Year End - 2019,” “Option Exercises and Stock Vested During 2019,” “Pension Benefits – 2019,” “Non-Qualified Deferred Compensation – 2019,” “Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability” and “Compensation of Non-Employee Directors – 2019 Director Compensation” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings “Share Ownership Information – Security Ownership of Management” and “Share Ownership Information – Principal

Shareholders” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information⁽¹⁾

The following table provides information as of December 31, 2019 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|--|--|--|--|
| Equity compensation plans approved by shareholders | 8,592,446 ⁽²⁾ | \$ 40.11 ⁽³⁾ | 12,273,358 ⁽⁴⁾ |
| Equity compensation plans not approved by shareholders | — | — | — |
| Total equity compensation plans | 8,592,446 ⁽²⁾ | \$ 40.11 ⁽³⁾ | 12,273,358 ⁽⁴⁾ |

⁽¹⁾ Subject to Compensation Committee certification

⁽²⁾ Includes 9,699 phantom stock units, 1,038,396 restricted stock units and 1,829,615 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares granted in 2017, reflects the actual payout percentage of 0% for performance shares using a total shareholder return metric and 100% for performance shares using safety and financial metrics. The actual number of shares issued can range from 0% to 200% of target depending on achievement of performance objectives. For performance-based stock options, amounts reflected in this table assume payout at 150% of target. The actual number of options issued can range from 0% to 150% of target depending on achievement of performance objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

⁽³⁾ This is the weighted average exercise price for the 5,714,737 options outstanding as of December 31, 2019.

⁽⁴⁾ Represents the total number of shares available for issuance under all PG&E Corporation's equity compensation plans as of December 31, 2019. Stock-based awards granted under these plans include restricted stock units, performance shares, stock options and phantom stock units. The 2014 LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the 2014 LTIP. In addition, 5.5 million shares related to awards outstanding under the 2006 LTIP at December 31, 2013 or awards granted under the 2006 LTIP from January 1, 2014 through May 11, 2014 were cancelled, forfeited or expired and became available for issuance under the 2014 LTIP.

For more information, see Note 6 of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information responding to Item 13, for each of PG&E Corporation and the Utility, will be included under the headings “Related Party Transactions” and “Corporate Governance – Board and Director General Independence and Qualifications” and “Corporate Governance – Committee Membership, Independence, and Qualifications” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to Item 14, for each of PG&E Corporation and the Utility, will be included under the heading “Information Regarding the Independent Auditor for PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2020 Annual Meetings of Shareholders, which information is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a. The following documents are filed as a part of this report:

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as part of this report in Item 8:

Consolidated Statements of Income for the Years Ended December 31, 2019, 2018, and 2017 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2019, 2018, and 2017 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2019 and 2018 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2019, 2018, and 2017 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2019, 2018, and 2017 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2019, 2018, and 2017 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Management's Report on Internal Controls.

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Condensed Financial Information of Parent as of December 31, 2019 and 2018 and for the Years Ended December 31, 2019, 2018, and 2017.

Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2019, 2018, and 2017.

3. Exhibits required by Item 601 of Regulation S-K

| Exhibit Number | Exhibit Description |
|-----------------------|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002, as amended by the Amendment dated June 21, 2019 [Conformed Copy] (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corporation amended as of April 10, 2019 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2019 (File No. 1-12609), Exhibit 3.1) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company, amended as of October 11, 2019 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2019 (File No. 1-2348), Exhibit 3.1) |
| 4.1 | Indenture, dated as of August 6, 2018, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture, dated as of August 6, 2018, relating to the issuance by Pacific Gas and Electric Company of \$500,000,000 aggregate principal amount of 4.25% Senior Notes due August 1, 2023 and \$300,000,000 aggregate principal amount of 4.65% Senior Notes due August 1, 2028 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.2) |
| 4.3 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | First Supplemental Indenture, dated as of March 13, 2007, relating to the issuance of \$700,000,000 principal amount of Pacific Gas and Electric Company's 5.80% Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Third Supplemental Indenture, dated as of March 3, 2008, relating to the issuance of \$400,000,000 of Pacific Gas and Electric Company's 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Sixth Supplemental Indenture, dated as of March 6, 2009, relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.8 | Ninth Supplemental Indenture, dated as of April 1, 2010, relating to the issuance of \$250,000,000 aggregate principal amount of its 5.80% Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Tenth Supplemental Indenture, dated as of September 15, 2010, relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Twelfth Supplemental Indenture, dated as of November 18, 2010, relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and \$250,000,000 aggregate principal amount of its 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |

- 4.11 Thirteenth Supplemental Indenture, dated as of May 13, 2011, relating to the issuance of \$300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1)
- 4.12 Fourteenth Supplemental Indenture, dated as of September 12, 2011, relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1)
- 4.13 Sixteenth Supplemental Indenture, dated as of December 1, 2011, relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)
- 4.14 Seventeenth Supplemental Indenture, dated as of April 16, 2012, relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)
- 4.15 Eighteenth Supplemental Indenture, dated as of August 16, 2012, relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and \$350,000,000 aggregate principal amount of its 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)
- 4.16 Nineteenth Supplemental Indenture, dated as of June 14, 2013, relating to the issuance of \$375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and \$375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)
- 4.17 Twentieth Supplemental Indenture, dated as of November 12, 2013, relating to the issuance of \$300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and \$500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1)
- 4.18 Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of \$450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and \$450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No. 1-2348), Exhibit 4.1)
- 4.19 Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of \$350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and \$225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1-2348), Exhibit 4.1)
- 4.20 Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of \$500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1-2348), Exhibit 4.1)
- 4.21 Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and \$100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1)
- 4.22 Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of \$200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and \$450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1)
- 4.23 Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of \$600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1)

- 4.24 Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016, relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 30, 2017 and \$400,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1)
- 4.25 Twenty-Ninth Supplemental Indenture, dated as of March 10, 2017, relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.30% Senior Notes due March 15, 2027 and \$200,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 10, 2017 (File No. 1-2348), Exhibit 4.1)
- 4.26 Indenture, dated as of November 29, 2017, relating to the issuance of \$500,000,000 aggregate principal amount of by Pacific Gas and Electric Company's Floating Rate Senior Notes due November 28, 2018, \$1,150,000,000 aggregate principal amount of its 3.30% Senior Notes due December 1, 2027 and \$850,000,000 aggregate principal amount of its 3.95% Senior Notes due December 1, 2047 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 4.1)
- 4.27 Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 dated February 11, 2014 (File No. 333-193880), Exhibit 4.1)
- 4.28 First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of \$350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1)
- 4.29 Registration Rights Agreement, dated as of August 6, 2018, among Pacific Gas and Electric Company, Goldman Sachs & Co. LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC and SMBC Nikko Securities America, Inc., as representatives of the initial purchasers (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.5)
- 4.30(a) Description of PG&E Corporation's Securities – Common Stock
- 4.30(b) Description of Pacific Gas and Electric Company's Securities – Preferred Stock
- 10.1 Senior Secured Superpriority Debtor-in-Possession Credit, Guaranty and Security Agreement, dated as of February 1, 2019, among Pacific Gas and Electric Company, PG&E Corporation, the financial institutions from time to time party thereto, as lenders and issuing lenders, JPMorgan Chase Bank, N.A., as administrative agent, and Citibank, N.A., as collateral agent (incorporated by reference to PG&E Corporation's Form 8-K dated February 1, 2019 (File No. 1-12609), Exhibit 10.1)
- 10.2 Second Amended and Restated Credit Agreement, dated as of April 27, 2015, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank, National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1)
- 10.3 Second Amended and Restated Credit Agreement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2)

- 10.4 Term Loan Agreement, dated as of April 16, 2018, by and among PG&E Corporation, the several banks and other financial institutions or entities from time to time parties thereto, Mizuho Bank, Ltd., Royal Bank of Canada and Sumitomo Mitsui Banking Corporation, as joint lead arrangers and joint bookrunners and Mizuho Bank, Ltd., as administrative agent (incorporated by reference to PG&E Corporation's Form 8-K dated April 16, 2018 (File No. 001-12609), Exhibit 10.1)
- 10.5 Term Loan Agreement, dated as of February 23, 2018, by and among Pacific Gas and Electric Company, the several banks and other financial institutions or entities from time to time parties thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd. and U.S. Bank National Association, as joint lead arrangers and joint bookrunners and The Bank of Tokyo-Mitsubishi UFJ, Ltd, as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 23, 2018 (File No. 001-02348), Exhibit 10.1)
- 10.6 Purchase Agreement, dated as of August 2, 2018, among Pacific Gas and Electric Company, Goldman Sachs & Co. LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC and SMBC Nikko Securities America, Inc. as representatives of the initial purchasers listed on Schedules I-A and I-B thereto (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 10.1)
- 10.7 Purchase Agreement, dated as of November 27, 2017, among Pacific Gas and Electric Company and Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers listed on Schedules I-A, I-B and I-C thereto (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 10.1)
- 10.8 Settlement Agreement among the California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K dated December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
- 10.9 Pacific Gas and Electric Company Commitment Letter dated October 4, 2019 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 11, 2019 (File No. 1-2348), Exhibit 10.1)
- 10.10 PG&E Corporation Commitment Letter dated October 4, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated October 11, 2019 (File No. 1-12609), Exhibit 10.2)
- 10.11 Amendment No. 1 to Pacific Gas and Electric Company Commitment Letter dated November 18, 2019
- 10.12 Amendment No. 1 to PG&E Corporation Commitment Letter dated November 18, 2019
- 10.13 Amendment No. 2 to Pacific Gas and Electric Company Commitment Letter dated December 20, 2019 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 20, 2019 (File No. 1-2348), Exhibit 10.3)
- 10.14 Amendment No. 2 to PG&E Corporation Commitment Letter dated December 20, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated December 20, 2019 (File No. 1-12609), Exhibit 10.2)
- 10.15 Amendment No. 3 to Pacific Gas and Electric Company Commitment Letter dated January 31, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated January 31, 2020 (File No. 1-2348), Exhibit 10.3)
- 10.16 Amendment No. 3 to PG&E Corporation Commitment Letter dated January 31, 2020 (incorporated by reference to PG&E Corporation's Form 8-K dated January 31, 2020 (File No. 1-12609), Exhibit 10.2)
- 10.17 Amendment No. 4 to Pacific Gas and Electric Company Commitment Letter dated February 14, 2020
- 10.18 Amendment No. 4 to PG&E Corporation Commitment Letter dated February 14, 2020
- 10.19 *** Form of Chapter 11 Plan Backstop Commitment Letter (incorporated by reference to PG&E Corporation's Form 8-K dated December 20, 2019 (File No. 1-12609), Exhibit 10.1)

- 10.20 **** Restructuring Support Agreement dated as of September 22, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company, certain affiliates of American International Group, Inc., Allstate Insurance Company and certain affiliates, BG Group A Creditors, BG Group B Creditors, certain affiliates of Farmers Insurance Exchange, California Insurance Guarantee Association, Hartford Accident & Indemnity Company and certain affiliates, certain affiliates of Liberty Mutual Insurance Company, Nationwide Mutual Insurance Company and certain affiliates, State Farm Mutual Automobile Insurance Company, State Farm County Mutual Insurance Company of Texas, State Farm Fire and Casualty Company, State Farm General Insurance Company, TLFI Investments, LLC (in its capacity as holder of an economic interest in certain Subrogation Claims), The Travelers Indemnity Company and certain of its property and casualty insurance affiliates, and certain affiliates of United Services Automobile Association (incorporated by reference to PG&E Corporation's Form 8-K dated September 22, 2019 (File No. 1-12609, Exhibit 10.1))
- 10.21 **** First Amendment to Restructuring Support Agreement dated as of October 24, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.22 **** Amended and Restated Restructuring Support Agreement dated as of November 1, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company, certain affiliates of American International Group, Inc., BG Group A Creditors, BG Group B Creditors, certain affiliates of Farmers Insurance Exchange, California Insurance Guarantee Association, Hartford Accident & Indemnity Company and certain affiliates, certain affiliates of Liberty Mutual Insurance Company, Nationwide Mutual Insurance Company and certain affiliates, State Farm Mutual Automobile Insurance Company, State Farm County Mutual Insurance Company of Texas, State Farm General Insurance Company, TLFI Investments, LLC (in its capacity as holder of an economic interest in certain Subrogation Claims), The Travelers Indemnity Company and certain of its property and casualty insurance affiliates, and certain affiliates of United Services Automobile Association
- 10.23 **** First Amendment to Amended and Restated Restructuring Support Agreement, dated as of November 13, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.24 **** Second Amendment to Amended and Restated Restructuring Support Agreement, dated as of November 18, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.25 **** Third Amendment to Amended and Restated Restructuring Support Agreement, dated as of December 6, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.26 **** Fourth Amendment to Amended and Restated Restructuring Support Agreement, dated as of December 10, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.27 **** Fifth Amendment to Amended and Restated Restructuring Support Agreement, dated as of December 16, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.28 **** Sixth Amendment to Amended and Restated Restructuring Support Agreement, dated as of December 18, 2019, among PG&E Corporation and Pacific Gas and Electric Company and the Requisite Consenting Creditors
- 10.29 Restructuring Support Agreement dated as of December 6, 2019, by and among PG&E Corporation and Pacific Gas and Electric Company, the Official Committee of Tort Claimants, the attorneys and other advisors and agents for holders of Fire Victim Claims that are signatories to the RSA, and certain funds and accounts managed or advised by Abrams Capital Management, LP and certain funds and accounts managed or advised by Knighthead Capital Management, LLC (incorporated by reference to PG&E Corporation's Form 8-K dated December 6, 2019 (File No. 1-12609), Exhibit 10.1)
- 10.30 First Amendment to the Restructuring Support Agreement, dated as of December 16, 2019, by and among PG&E Corporation and Pacific Gas and Electric Company, the Shareholder Proponents and the Requisite Consenting Fire Claimant Professionals (incorporated by reference to PG&E Corporation's Form 8-K dated December 16, 2019 (File No. 1-12609), Exhibit 10.1)
- 10.31 Restructuring Support Agreement dated as of January 22, 2020, by and among PG&E Corporation and Pacific Gas and Electric Company, the holders of senior unsecured debt of Pacific Gas and Electric Company that are signatories to the RSA, and certain funds and accounts managed or advised by Abrams Capital Management, LP and certain funds and accounts managed or advised by Knighthead Capital Management, LLC (incorporated by reference to PG&E Corporation's Form 8-K dated January 23, 2020 (File No. 1-12609), Exhibit 10.1)

- 10.32 Agency Appointment and Assumption Agreement dated as of September 13, 2019, by and among Wilmington Trust, National Association, in its capacity as Successor Agent, PG&E Corporation, as borrower, and the Lenders signatory thereto, constituting the Required Lenders (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2019 (File No. 1-12609), Exhibit 10.6)
- 10.33 Plan Support Agreement as to Plan Treatment of Public Entities' Wildfire Claims dated as of June 18, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company, 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 (incorporated by reference to PG&E Corporation's Form 8-K dated June 18, 2019 (File No. 1-12609), Exhibit 10.1)
- 10.34 Plan Support Agreement as to Plan Treatment of Public Entity's Wildfire Claims dated as of June 18, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company and the Town of Paradise (incorporated by reference to PG&E Corporation's Form 8-K dated June 18, 2019 (File No. 1-12609), Exhibit 10.2)
- 10.35 Plan Support Agreement as to Plan Treatment of Public Entity's Wildfire Claims dated as of June 18, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company and the County of Butte (incorporated by reference to PG&E Corporation's Form 8-K dated June 18, 2019 (File No. 1-12609), Exhibit 10.3)
- 10.36 Plan Support Agreement as to Plan Treatment of Public Entity's Wildfire Claims dated as of June 18, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company and the Paradise Recreation & Park District (incorporated by reference to PG&E Corporation's Form 8-K dated June 18, 2019 (File No. 1-12609), Exhibit 10.4)
- 10.37 Plan Support Agreement as to Plan Treatment of Public Entity's Wildfire Claims dated as of June 18, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company and the County of Yuba (incorporated by reference to PG&E Corporation's Form 8-K dated June 18, 2019 (File No. 1-12609), Exhibit 10.5)
- 10.38 Plan Support Agreement as to Plan Treatment of Public Entity's Wildfire Claims dated as of June 18, 2019, by and among PG&E Corporation, Pacific Gas and Electric Company and the Calaveras County Water District (incorporated by reference to PG&E Corporation's Form 8-K dated June 18, 2019 (File No. 1-12609), Exhibit 10.6)
- 10.39 Settlement Agreement, dated April 22, 2019, by and between PG&E Corporation and BlueMountain Capital Management, LLC (incorporated by reference to PG&E Corporation's Form 8-K dated April 22, 2019 (File No. 1-12609), Exhibit 10.1)
- 10.40 Amendment No. 1 to Settlement Agreement, dated September 3, 2019, by and between PG&E Corporation and BlueMountain Capital Management, LLC (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2019, Exhibit 10.1)
- 10.41 Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)
- 10.42 * Performance Based Stock Option Agreement between William D. Johnson and PG&E Corporation for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
- 10.43 * Performance Share Agreement subject to financial goals between William D. Johnson and PG&E Corporation dated August 14, 2019 for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
- 10.44 * Performance Share Agreement subject to customer affordability goals between William D. Johnson and PG&E Corporation dated August 14, 2019 for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
- 10.45 * Performance Share Agreement subject to safety goals between William D. Johnson and PG&E Corporation dated August 14, 2019 for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan
- 10.46 * Restricted Stock Unit Agreement between William D. Johnson and PG&E Corporation for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan

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| 10.47 | * | Restricted Stock Unit Agreement between Andrew M. Vesey and PG&E Corporation for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.48 | * | Offer Letter between Pacific Gas and Electric Company and Andrew M. Vesey dated July 30, 2019 (incorporated by reference to Pacific Gas and Electric's Form 10-Q for the quarter ended September 30, 2019 (File No. 1-2348), Exhibit 10.7) |
| 10.49 | * | Performance Share Agreement subject to financial goals between Andrew M. Vesey and PG&E Corporation dated November 12, 2019 for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.50 | * | Performance Share Agreement subject to customer affordability goals between Andrew M. Vesey and PG&E Corporation dated November 12, 2019 for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.51 | * | Performance Share Agreement subject to safety goals between Andrew M. Vesey and PG&E Corporation dated November 12, 2019 for 2019 grant under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 10.52 | * | Form of Director and Officer Indemnification Agreement (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 10.8) |
| 10.53 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of June 3, 2019 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 10.9) |
| 10.54 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective as of June 3, 2019 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 10.10) |
| 10.55 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and David S. Thomason dated May 24, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-2348), Exhibit 10.2) |
| 10.56 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and David S. Thomason dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.1) |
| 10.57 | * | Performance Share Award Agreement subject to financial goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.2) |
| 10.58 | * | Performance Share Award Agreement subject to safety and customer affordability goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.3) |
| 10.59 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Janet Loduca dated December 3, 2018 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2018 (File No. 1-12609), Exhibit 10.27) |
| 10.60 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10) |
| 10.61 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.62 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2018 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.03) |
| 10.63 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.64 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |

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| 10.65 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.31) |
| 10.66 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.67 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2015 (File No. 1-2348), Exhibit 10.38) |
| 10.68 | * | Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective February 16, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-2348), Exhibit 10.4) |
| 10.69 | * | Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective February 6, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2014 (File No. 1-2348), Exhibit 10.37) |
| 10.70 | * | Postretirement Life Insurance Plan of Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.71 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.27) |
| 10.72 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2018 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2017 (File No. 1-12609), Exhibit 10.54) |
| 10.73 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.74 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended effective as of May 16, 2001 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.75 | * | Form of Restricted Stock Unit Agreement for 2018 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2018 (File No. 1-12609), Exhibit 10.04) |
| 10.76 | * | Form of Restricted Stock Unit Agreement for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.07) |
| 10.77 | * | Form of Restricted Stock Unit Agreement for 2017 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.07) |
| 10.78 | * | Form of Restricted Stock Unit Agreement for 2016 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609), Exhibit 10.1) |
| 10.79 | * | Form of Restricted Stock Unit Agreement for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.01) |
| 10.80 | * | Form of Restricted Stock Unit Agreement for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.55) |
| 10.81 | * | Form of Stock Option Agreement for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.08) |
| 10.82 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 8-K dated January 6, 2005 (File No. 1-12609), Exhibit 99.1) |

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| 10.83 | * | Form of Stock Award Agreement for 2019 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan, as amended February 6, 2020 |
| 10.84 | * | Form of Performance Share Agreement subject to financial goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.04) |
| 10.85 | * | Form of Performance Share Agreement subject to safety goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.05) |
| 10.86 | * | Form of Performance Share Agreement subject to total shareholder return goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.06) |
| 10.87 | * | Form of Performance Share Agreement subject to total shareholder return goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.02) |
| 10.88 | * | Form of Performance Share Agreement subject to financial goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.61) |
| 10.89 | * | Form of Performance Share Agreement subject to safety and financial goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.03) |
| 10.90 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.63) |
| 10.91 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted on September 14, 2010 and effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.92 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.93 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.94 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.95 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.96 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.01) |
| 10.97 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.2) |
| 10.98 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective February 21, 2018 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2018 (File No. 1-12609), Exhibit 10.04) |
| 10.99 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.100 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |

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| 21 | | Subsidiaries of the Registrant |
| 23.1 | | PG&E Corporation Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 31.1 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | ** | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | | XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. |
| 101.SCH | | XBRL Taxonomy Extension Schema Document |
| 101.CAL | | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | | XBRL Taxonomy Extension Definition Linkbase Document |
| 104 | | Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101) |
| <hr/> | | |
| * | | Management contract or compensatory agreement. |
| ** | | Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report. |
| *** | | This Form of Chapter 11 Plan Backstop Commitment Letter is substantially similar in all material respects to each Chapter 11 Plan Backstop Commitment Letter that is otherwise required to be filed as an exhibit, except as to the Backstop Party and the amount of such Backstop Party's Backstop Commitment Amount (as defined in the Chapter 11 Plan Backstop Commitment Letter). In accordance with instruction no. 2 to Item 601 of Regulation S-K, the registrant has filed the form of such Chapter 11 Plan Backstop Commitment Letter, with a schedule identifying the Chapter 11 Plan Backstop Commitment Letters omitted and setting forth the material details in which each Chapter 11 Plan Backstop Commitment Letter differs from the form that was filed. The registrant acknowledges that the Securities and Exchange Commission may at any time in its discretion require filing of copies of any Chapter 11 Plan Backstop Commitment Letter so omitted. |
| **** | | In accordance with Item 601(a)(5) of Regulation S-K, certain schedules or similar attachments to this exhibit have been omitted from this filing. Such omitted schedules or similar attachments include information about the Subrogation Claims held by each Consenting Subrogation Creditor. The registrant agrees to furnish a supplemental copy of any omitted schedule or similar attachment to the Securities and Exchange Commission upon request. |

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2019 to be signed on their behalf by the undersigned, thereunto duly authorized.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

PG&E CORPORATION
(Registrant)

PACIFIC GAS AND ELECTRIC COMPANY
(Registrant)

/s/ WILLIAM D. JOHNSON
William D. Johnson

/s/ ANDREW M. VESEY
Andrew M. Vesey

By: Chief Executive Officer and President

By: Chief Executive Officer and President

Date: February 18, 2020

Date: February 18, 2020

Signature
A. Principal Executive Officers

Title

Date

/s/ WILLIAM D. JOHNSON
William D. Johnson

Chief Executive Officer and President
(PG&E Corporation)

February 18, 2020

/s/ ANDREW M. VESEY
Andrew M. Vesey

Chief Executive Officer and President
(Pacific Gas and Electric Company)

February 18, 2020

/s/ JASON P. WELLS
Jason P. Wells

Executive Vice President and Chief Financial
Officer
(PG&E Corporation)

February 18, 2020

/s/ DAVID S. THOMASON
David S. Thomason

Vice President, Chief Financial Officer, and
Controller (Pacific Gas and Electric Company)

February 18, 2020

C. Principal Accounting Officer

/s/ DAVID S. THOMASON
David S. Thomason

Vice President, Chief Financial Officer, and
Controller (Pacific Gas and Electric Company)

February 18, 2020

D. Directors (PG&E Corporation and Pacific Gas and Electric Company, unless otherwise noted)

| | | | |
|---|--|---|-------------------|
| * | /s/ RICHARD R. BARRERA Richard R. Barrera | Director | February 18, 2020 |
| * | /s/ JEFFREY L. BLEICH Jeffrey L. Bleich | Director Chair of the Board (Pacific Gas and Electric Company) | February 18, 2020 |
| * | /s/ NORA MEAD BROWNELL Nora Mead Brownell | Director Chair of the Board (PG&E Corporation) | February 18, 2020 |
| * | /s/ CHERYL F. CAMPBELL Cheryl F. Campbell | Director | February 18, 2020 |
| * | /s/ FRED J. FOWLER Fred J. Fowler | Director | February 18, 2020 |
| * | /s/ WILLIAM D. JOHNSON William D. Johnson | Director | February 18, 2020 |
| * | /s/ MICHAEL J. LEFFELL Michael J. Leffell | Director | February 18, 2020 |
| * | /s/ DOMINIQUE MIELLE Dominique Mielle | Director | February 18, 2020 |
| * | /s/ MERIDEE A. MOORE Meridee A. Moore | Director | February 18, 2020 |
| * | /s/ ERIC D. MULLINS Eric D. Mullins | Director | February 18, 2020 |

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| <p>* <u> /s/ KRISTINE M. SCHMIDT </u> Kristine M. Schmidt</p> | <p>Director</p> | <p>February 18, 2020</p> |
| <p>* <u> /s/ WILLIAM L. SMITH </u> William L. Smith</p> | <p>Director</p> | <p>February 18, 2020</p> |
| <p>* <u> /s/ ANDREW M. VESEY </u> Andrew M. Vesey</p> | <p>Director (Pacific Gas and Electric Company)</p> | <p>February 18, 2020</p> |
| <p>* <u> /s/ ALEJANDRO D. WOLFF </u> Alejandro D. Wolff</p> | <p>Director</p> | <p>February 18, 2020</p> |
| <p>* <u> /s/ JOHN M. WOOLARD </u> John M. Woolard</p> | <p>Director</p> | <p>February 18, 2020</p> |
| <p>*By: <u> /s/ JANET C. LODUCA </u> Janet C. Loduca, Attorney-in-Fact</p> | | <p>February 18, 2020</p> |

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

| (in millions, except per share amounts) | Years Ended December 31, | | |
|---|--------------------------|-------------------|-----------------|
| | 2019 | 2018 | 2017 |
| Administrative service revenue | \$ 138 | \$ 90 | \$ 63 |
| Operating expenses | (114) | (91) | (5) |
| Interest income | 1 | 2 | 1 |
| Interest expense | (21) | (15) | (11) |
| Other income (expense) | 10 | (2) | 4 |
| Reorganization items, net | (26) | — | — |
| Equity in earnings of subsidiaries | (7,622) | (6,832) | 1,667 |
| Income before income taxes | (7,634) | (6,848) | 1,719 |
| Income tax provision (benefit) | 8 | 3 | 73 |
| Net income (loss) | \$ (7,642) | \$ (6,851) | \$ 1,646 |
| Other Comprehensive Income (Loss) | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of \$0, \$0, and \$0, at respective dates) | \$ (1) | \$ 4 | \$ 1 |
| Total other comprehensive income (loss) | (1) | 4 | 1 |
| Comprehensive Income (Loss) | \$ (7,643) | \$ (6,847) | \$ 1,647 |
| Weighted Average Common Shares Outstanding, Basic | 528 | 517 | 512 |
| Weighted Average Common Shares Outstanding, Diluted | 528 | 513 | 513 |
| Net earnings (loss) per common share, basic | \$ (14.50) | \$ (13.25) | \$ 3.21 |
| Net earnings (loss) per common share, diluted | \$ (14.50) | \$ (13.25) | \$ 3.21 |

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED BALANCE SHEETS

| (in millions) | Balance at December 31, | |
|---|-------------------------|------------------|
| | 2019 | 2018 |
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | \$ 448 | \$ 373 |
| Advances to affiliates | 120 | 44 |
| Income taxes receivable | 12 | 18 |
| Other current assets | 11 | — |
| Total current assets | 591 | 435 |
| Noncurrent Assets | | |
| Equipment | 2 | 2 |
| Accumulated depreciation | (2) | (2) |
| Net equipment | — | — |
| Investments in subsidiaries | 5,102 | 12,722 |
| Other investments | 173 | 162 |
| Intercompany receivable | — | — |
| Operating lease right of use asset | 6 | — |
| Deferred income taxes | 187 | 187 |
| Total noncurrent assets | 5,468 | 13,071 |
| Total Assets | \$ 6,059 | \$ 13,506 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | — | 300 |
| Long-term debt, classified as current | — | 350 |
| Accounts payable – other | 47 | 16 |
| Operating lease liabilities | 3 | — |
| Other current liabilities | 3 | 17 |
| Total current liabilities | 53 | 683 |
| Noncurrent Liabilities | | |
| Debtor-in-possession financing | — | — |
| Operating lease liabilities | 3 | — |
| Other noncurrent liabilities | 58 | 172 |
| Total noncurrent liabilities | 61 | 172 |
| Liabilities Subject to Compromise | 810 | — |
| Common Shareholders' Equity | | |
| Common stock | 13,038 | 12,910 |
| Reinvested earnings | (7,893) | (250) |
| Accumulated other comprehensive income (loss) | (10) | (9) |
| Total common shareholders' equity | 5,135 | 12,651 |
| Total Liabilities and Shareholders' Equity | \$ 6,059 | \$ 13,506 |

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

| | Year ended December 31, | | |
|--|-------------------------|---------------|--------------|
| | 2019 | 2018 | 2017 |
| Cash Flows from Operating Activities: | | | |
| Net income (loss) | \$ (7,642) | \$ (6,851) | \$ 1,646 |
| Adjustments to reconcile net income to net cash provided by operating | | | |
| Stock-based compensation amortization | 43 | 78 | 20 |
| Equity in earnings of subsidiaries | 7,622 | 6,833 | (1,667) |
| Deferred income taxes and tax credits-net | — | (62) | 139 |
| Reorganization items, net (Note 2) | 11 | — | — |
| Current income taxes receivable/payable | 6 | 9 | (2) |
| Liabilities subject to compromise | 28 | — | — |
| Other | (62) | 41 | (75) |
| Net cash provided by operating activities | 6 | 48 | 61 |
| Cash Flows From Investing Activities: | | | |
| Investment in subsidiaries | — | (45) | (455) |
| Dividends received from subsidiaries ⁽¹⁾ | — | — | 784 |
| Net cash provided by (used in) investing activities | — | (45) | 329 |
| Cash Flows From Financing Activities: | | | |
| Debtor-in-possession credit facility debt issuance costs | (16) | — | — |
| Borrowings under revolving credit facility | — | 425 | — |
| Repayments under revolving credit facility | — | (125) | — |
| Net issuances (repayments) of commercial paper, net of discount of \$1 in 2017 | — | (132) | 132 |
| Short-term debt financing | — | 350 | — |
| Long-term debt matured or repurchased | — | (350) | — |
| Common stock issued | 85 | 200 | 395 |
| Common stock dividends paid ⁽²⁾ | — | — | (1,021) |
| Net cash provided by (used in) financing activities | 69 | 368 | (494) |
| Net change in cash and cash equivalents | 75 | 371 | (104) |
| Cash and cash equivalents at January 1 | 373 | 2 | 106 |
| Cash and cash equivalents at December 31 | \$ 448 | \$ 373 | \$ 2 |
| Supplemental disclosures of cash flow information | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | \$ (3) | \$ (13) | \$ (9) |
| Income taxes, net | — | 10 | — |
| Supplemental disclosures of noncash investing and financing activities | | | |
| Common stock dividends declared but not yet paid | \$ — | \$ — | \$ — |
| Noncash common stock issuances | — | — | 21 |
| Operating lease liabilities arising from obtaining ROU assets | 9 | — | — |

⁽¹⁾ Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries as an investing cash flow. On December 20, 2017, the Board of Directors of the Utility suspended quarterly cash dividends on the Utility's common stock, beginning the fourth quarter of 2017.

⁽²⁾ On December 20, 2017, the Board of Directors of PG&E Corporation suspended quarterly cash dividends on PG&E Corporation's common stock, beginning the fourth quarter of 2017. In July and October of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of \$0.53 per share. In January and April of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of \$0.49 per share.

PG&E CORPORATION
(DEBTOR-IN-POSSESSION)
SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2019, 2018, and 2017
(in millions)

| (in millions) | | Additions | | | | | |
|---|--------------------------------|-------------------------------|---------------------------|---------------------------|--------------------------|--|--|
| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions ⁽²⁾ | Balance at End of Period | | |
| Valuation and qualifying accounts deducted from assets: | | | | | | | |
| 2019: | | | | | | | |
| Allowance for uncollectible accounts ⁽¹⁾ | \$ 56 | \$ — | \$ — | \$ 13 | \$ 43 | | |
| 2018: | | | | | | | |
| Allowance for uncollectible accounts ⁽¹⁾ | \$ 64 | \$ 34 | \$ — | \$ 42 | \$ 56 | | |
| 2017: | | | | | | | |
| Allowance for uncollectible accounts ⁽¹⁾ | \$ 58 | \$ 55 | \$ — | \$ 49 | \$ 64 | | |

⁽¹⁾ Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."

⁽²⁾ Deductions consist principally of write-offs, net of collections of receivables previously written off.

PACIFIC GAS AND ELECTRIC COMPANY
(DEBTOR-IN-POSSESSION)
SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2019, 2018, and 2017

(in millions)

| (in millions) | | Additions | | | | | |
|---|--------------------------------------|-------------------------------------|------|---------------------------------|-------|---------------------------|-----------------------------|
| Description | Balance at Beginning of Period | Charged to Costs and Expenses | | Charged to Other Accounts | | Deductions ⁽²⁾ | Balance at End of Period |
| | | | | | | | |
| Valuation and qualifying accounts deducted from assets: | | | | | | | |
| 2019: | | | | | | | |
| Allowance for uncollectible accounts ⁽¹⁾ | \$ 56 | \$ — | \$ — | \$ — | \$ 13 | \$ 43 | |
| 2018: | | | | | | | |
| Allowance for uncollectible accounts ⁽¹⁾ | \$ 64 | \$ 34 | \$ — | \$ 42 | \$ 56 | | |
| 2017: | | | | | | | |
| Allowance for uncollectible accounts ⁽¹⁾ | \$ 58 | \$ 55 | \$ — | \$ 49 | \$ 64 | | |

⁽¹⁾ Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."

⁽²⁾ Deductions consist principally of write-offs, net of collections of receivables previously written off.

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Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company⁽¹⁾

RICHARD R. BARRERA

Founder, CEO and Portfolio Manager, Roystone Capital Management LP

JEFFREY L. BLEICH⁽²⁾

Attorney, former Special Counsel to the President, U.S. Ambassador, and California State Bar President

NORA MEAD BROWNELL⁽³⁾

Co-Founder of Espy Energy Solutions, LLC

CHERYL F. CAMPBELL

Consultant, Executive Director, Gold Shovel Standard Association

FRED J. FOWLER

Retired Chairman of the Board, Spectra Energy Partners, LP

WILLIAM D. JOHNSON

Chief Executive Officer and President, PG&E Corporation

MICHAEL J. LEFFELL

Founder, Portage Partners LLC and Chairman, Canoe Software

DOMINIQUE MIELLE

Former Partner and Senior Portfolio Manager, Canyon Partners, LLC

MERIDEE A. MOORE

Founder, CEO and Chief Investment Officer, Watershed Asset Management, L.L.C.

ERIC D. MULLINS

Co-CEO, Lime Rock Resources, L.P.

KRISTINE M. SCHMIDT

Former Chief Executive Officer, Peak Utility Services Group

WILLIAM L. SMITH

Retired President of AT&T Technology Operations, AT&T Services, Inc.

ANDREW M. VESEY⁽⁴⁾

Chief Executive Officer and President, Pacific Gas and Electric Company

ALEJANDRO D. WOLFF

Former Managing Director, Gryphon Partners

JOHN M. WOOLARD

Chief Executive Officer, Meridian Energy and Senior Operating Partner, Activate Capital

(1) As of March 30, 2020.

(2) Jeffrey L. Bleich is the non-executive Chair of the Board of Pacific Gas and Electric Company.

(3) Nora Mead Brownell is the non-executive Chair of the Board of PG&E Corporation.

(4) Andrew M. Vesey is a director of Pacific Gas and Electric Company only.

PG&E Corporation Officers⁽¹⁾

NORA MEAD BROWNELL

Non-Executive Chair of the Board

WILLIAM D. JOHNSON

Chief Executive Officer and President

JOHN R. SIMON

Executive Vice President, Law, Strategy and Policy

JASON P. WELLS

Executive Vice President and Chief Financial Officer

JULIE M. KANE

Senior Vice President, Chief Ethics and Compliance Officer, and Deputy General Counsel

JANET C. LODUCA

Senior Vice President and General Counsel

DINYAR B. MISTRY

Senior Vice President, Human Resources

FRANCISCO BENAVIDES

Vice President and Chief Safety Officer

STEPHEN J. CAIRNS

Vice President, Internal Audit and Chief Risk Officer

LINDA Y.H. CHENG

Vice President

CHRISTOPHER A. FOSTER

Vice President, Investor Relations

JESSICA C. HOGLE

Vice President, Federal Affairs and Chief Sustainability Officer

DAVID S. THOMASON

Vice President and Controller

BRIAN M. WONG

Vice President, Deputy General Counsel, and Corporate Secretary

(1) As of March 30, 2020.

Pacific Gas and Electric Company Officers⁽¹⁾

JEFFREY L. BLEICH

Non-Executive Chair of the Board

ANDREW M. VESEY

Chief Executive Officer and President

LORAIN M. GIAMMONA

Senior Vice President and Chief Customer Officer

JULIE M. KANE

Senior Vice President, Chief Ethics and Compliance Officer, and Deputy General Counsel

KATHLEEN B. KAY

Senior Vice President and Chief Information Officer

MICHAEL A. LEWIS

Senior Vice President, Electric Operations

JANET C. LODUCA

Senior Vice President and General Counsel

DINYAR B. MISTRY

Senior Vice President, Human Resources

FONG WAN

Senior Vice President, Energy Policy and Procurement

JAMES M. WELSCH

Senior Vice President, Generation and Chief Nuclear Officer

AHMAD ABABNEH

Vice President, Electric Operations Major Projects and Programs

DEBORAH T. AFFONSA

Vice President, Customer Service

FRANCISCO BENAVIDES

Vice President and Chief Safety Officer

STEPHEN J. CAIRNS

Vice President, Internal Audit and Chief Risk Officer

LINDA Y.H. CHENG

Vice President

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

DAVID E. HATTON

Vice President, Human Resources Solutions

AARON J. JOHNSON

Vice President, Wildfire Safety and Public Engagement

ROBERT S. KENNEY

Vice President, State and Regulatory Affairs

PETER E. KENNY

Vice President, Gas Transmission and Distribution Construction

MARY K. KING

Vice President, Talent and Chief Diversity Officer

ROY M. KUGA

Vice President, Energy Policy and Procurement Bankruptcy Strategy

JAMIE L. MARTIN

Vice President and Chief Procurement Officer

JAN A. NIMICK

Vice President, Power Generation

DEBORAH W. POWELL

Vice President, Asset, Risk Management, and Community Wildfire Safety Program

KEITH F. STEPHENS

Vice President, Corporate Relations and Chief Communications Officer

DAVID S. THOMASON

Vice President, Chief Financial Officer, and Controller

KENNETH J. WELLS

Vice President, Electric Distribution Operations

ANDREW K. WILLIAMS

Vice President, Shared Services

STEPHANIE WILLIAMS

Vice President, Business Finance and Planning

BRIAN M. WONG

Vice President, Deputy General Counsel, and Corporate Secretary

(1) As of March 30, 2020.

Shareholder Information

For financial and other information about PG&E Corporation and Pacific Gas and Electric Company, please visit our websites, www.pgecorp.com and www.pge.com, respectively. PG&E Corporation is the holder of all issued and outstanding shares of Pacific Gas and Electric Company common stock.

If you have questions about your PG&E Corporation common stock account or Pacific Gas and Electric Company preferred stock account, please contact our transfer agent, EQ Shareowner Services (“EQ”).

EQ Shareowner Services

P. O. Box 64874
St. Paul, MN 55164-0874

Toll-free telephone services: 1-888-489-4689 (Representatives are available Monday through Friday from 7:00 a.m. CT to 7:00 p.m. CT)

Website: www.shareowneronline.com

Lost or Stolen Stock Certificates

If you hold stock in your own name and your stock certificate has been lost, stolen, or in some way destroyed, you should immediately notify EQ.

Stock Held in Brokerage Accounts (“Street Name”)

When you purchase your stock and it is held for you by your broker, the shares are listed with EQ in the broker’s name, or street name. EQ does not know the identity of the individual shareholders who hold their shares in this manner. If you hold your stock in a street name account, you receive all tax forms, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

Stock Exchange Listings

PG&E Corporation’s common stock is listed on the New York Stock Exchange under the symbol “PCG.”

Pacific Gas and Electric Company has eight issues of first preferred cumulative stock, par value \$25 per share, all of which are listed on NYSE American.

Non-Redeemable:

| Issue | Symbol |
|-------|--------|
| 6.00% | PCG-PA |
| 5.50% | PCG-PB |
| 5.00% | PCG-PC |

Redeemable:

| Issue | Symbol |
|----------------|--------|
| 5.00% | PCG-PD |
| 5.00% Series A | PCG-PE |
| 4.80% | PCG-PG |
| 4.50% | PCG-PH |
| 4.36% | PCG-PI |

If you have general questions about PG&E Corporation or Pacific Gas and Electric Company, please contact the Corporate Secretary's Office.

Vice President, Deputy General Counsel, and Corporate Secretary

Brian M. Wong

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Pacific Gas and Electric Company
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Fax: 415-973-8719
Email: CorporateSecretary@pge.com

Securities analysts, portfolio managers, or other representatives of the investment community should contact the Investor Relations Office.

Vice President, Investor Relations

Christopher A. Foster

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